2023 Integrated Resource Plan

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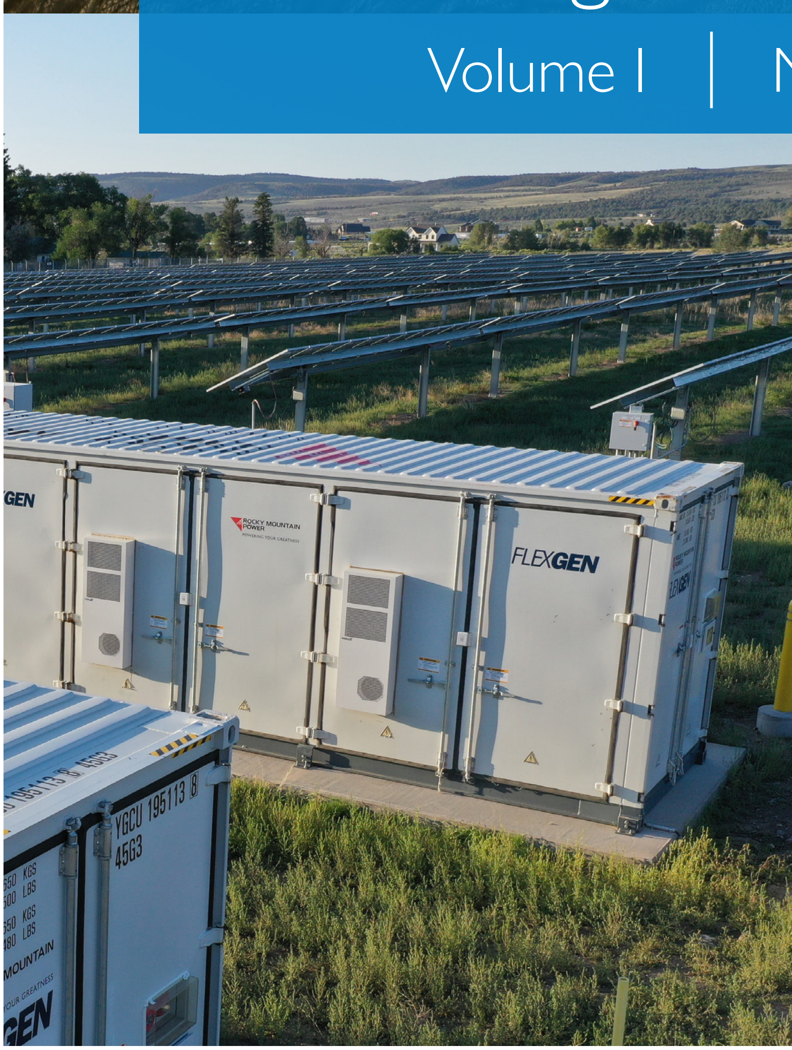

PACIFICORP

This 2023 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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CHAPTER 1 – EXECUTIVE SUMMARY

Delivering on our promise

Our 2023 Integrated Resource Plan is a roadmap for transforming the western grid at scale. It builds toward a truly connected West, where the transition to a net-zero energy system delivers safe, reliable, affordable power now and for years to come.

This is more than a vision for the future; it is our promise to the communities we serve – one we're already delivering on, with steady progress toward ambitious targets for reducing greenhouse gas emissions and transitioning to cleaner energy sources.

As our 2023 IRP demonstrates, we've made significant headway in recent years by investing in transmission, renewable resources and market strategies – and by driving forward innovative technologies, such as batteries and advanced nuclear resources, to keep energy supplies reliable and affordable for customers across the region.

Now we're accelerating our efforts and investments. This IRP provides an update on our progress toward decarbonization and lays out our roadmap for the work still ahead of us.

CALLOUT BOX

OUR COMMITMENTS

Prioritizing savings and value for our customers

We've captured over $591 million in savings for our customers by leading the way in establishing more innovative markets, enabling us to deliver reliable service at rates 27% below the national average. Soon, we'll evolve how we buy and sell electricity even further to secure greater economic and reliability benefits for customers.

Expanding clean power

Through smart investments that keep costs low, we're on track to deliver over 20,000 megawatts of wind and solar energy by 2032.

Building storage capacity

We're working toward an energy storage capacity of nearly 7,400 megawatts by 2029.

Investing in transmission

Making progress on our ambitious Energy Gateway plan to add 2,500 miles of new transmission lines, we're doubling the connectivity between the Pacific Northwest and the Rocky Mountains to meet rising customer demand, while connecting clean energy across our system for a more resilient grid.

Roadmap

Responsible progress: The promise of a connected West
We're advancing a once-in-a-century investment in our critical infrastructure to meet the challenges of a rapidly changing economy, while laying the groundwork for long-term affordability and reliability and helping build a more resilient grid.

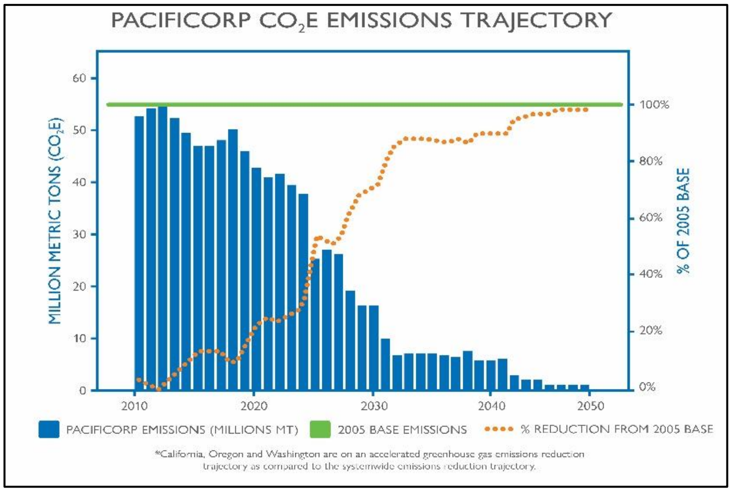
The 2023 IRP outlines PacifiCorp's bold vision for the West between now and 2042 and sets us on the path to:

- Continue our growth toward a grid powered by clean energy:
    - 9,111 megawatts of new wind resources.
    - 8,095 megawatts of storage resources, including batteries co-located with solar generation, standalone batteries and pumped hydro storage resources.
    - 7,855 megawatts of new solar resources (most paired with battery storage).
    - 4,953 megawatts of capacity saved through energy efficiency programs.
    - 929 megawatts of capacity saved through direct load control programs.
    - 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project) in 2030, with an additional 1,000 megawatts of advanced nuclear over the long term.
    - 1,240 megawatts of non-emitting peaking resources that meet high-demand energy needs.
- Connect and optimize these diverse, clean resources across the West with a strengthened and modernized transmission network that provides resilient service, reduces costs and creates greater opportunities for our communities to thrive:
    - 416 miles of new transmission from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South).
    - 290 miles of new transmission from the Longhorn substation in north central Oregon to the Hemingway substation in south central Idaho (Energy Gateway Segment H).
    - 200 miles of new transmission from the new Anticline substation near Point of Rocks, Wyoming, to the existing Populus substation near Downey, Idaho (Energy Gateway West Sub-Segment D3).
    - 150 miles of new transmission from the Anticline substation near Point of Rocks, Wyoming, to Shirley Basin substation in southeastern Wyoming (Energy Gateway West Sub-Segment D2.2).
    - 59 miles of new transmission from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming (Energy Gateway West Sub-Segment D1).
    - Additional local transmission upgrades to enable renewable resource requests to connect to the transmission system in southeast Idaho, central Utah, central Oregon, the Willamette Valley in Oregon, and in Yakima and Walla Walla, Washington.

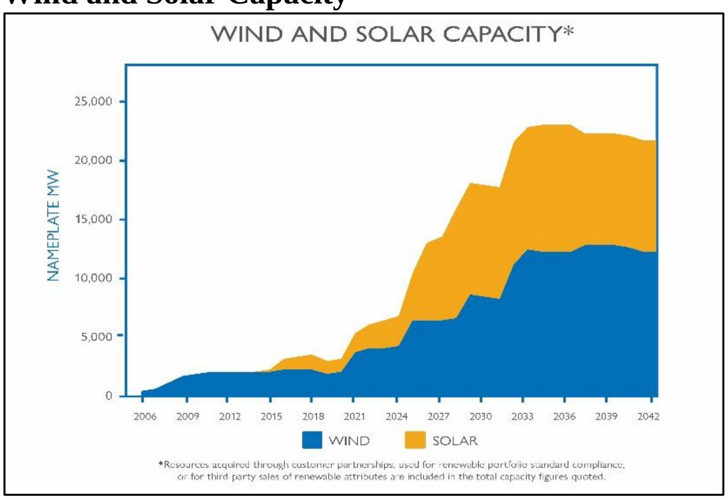
Accelerating Progress

Tracking our progress
PacifiCorp's 2023 IRP rapidly expands our portfolio of solar, wind and storage resources to lower costs. Innovative participation in new energy markets will leverage our six-state footprint and help further drive affordability.

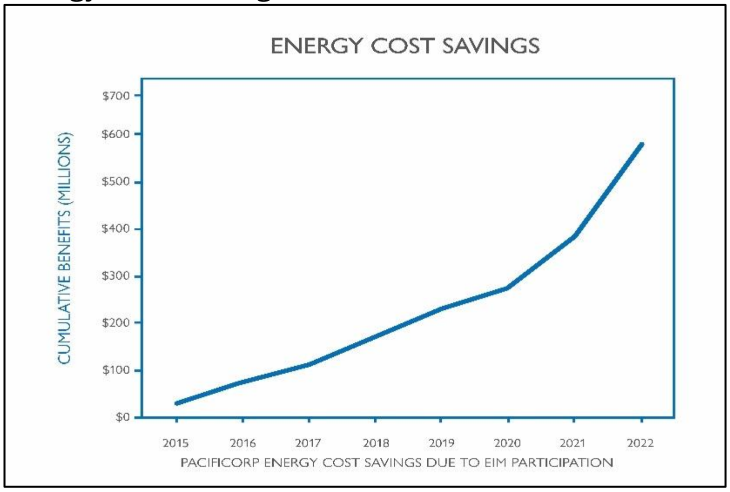
Emissions



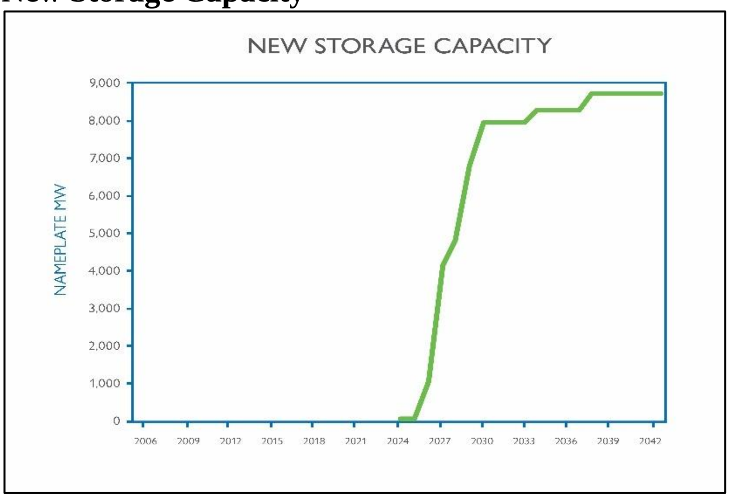
Wind and Solar Capacity



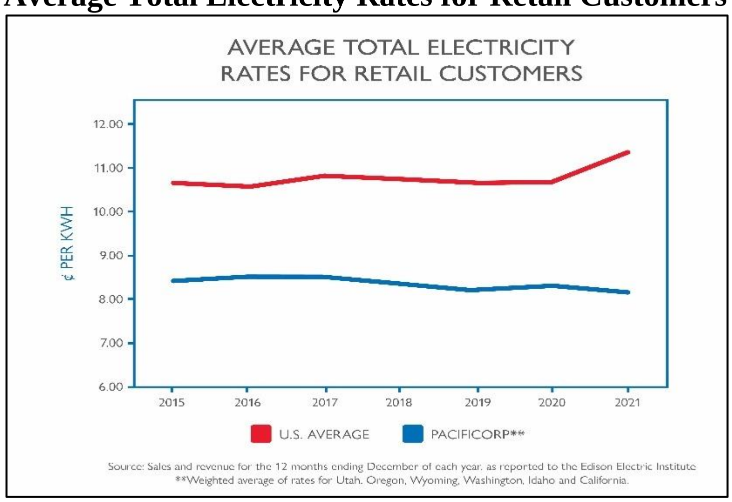
Energy Cost Savings



New Storage Capacity



Average Total Electricity Rates for Retail Customers



Changes to our portfolio

Evolving our portfolio
Working in close partnership with our communities, we are making significant progress in our evolution toward an increasingly clean and cost-effective portfolio.

Our resource strategy in the 2023 IRP continues that progress, and in the coming years we will:

- Exit the Colstrip project in Montana by 2030.
- Begin the process of a coal-to-gas conversion of Jim Bridger Units 3 and 4 in Rock Springs, Wyoming, for completion by 2030.
- Continue the process of coal-to-gas conversion of Naughton Units 1 and 2 in Kemmerer, Wyoming, for completion by 2026.
- Retire Dave Johnston Units 1, 2 and 3 in Glenrock, Wyoming, in 2027 and 2028.

Throughout this process, we are collaborating closely with affected communities and with state leadership to support a successful transition for our employees and their communities.

Partnerships and Innovation

Building partnerships for a thriving future

<u>Making electric vehicle ownership more accessible for customers and communities</u>
PacifiCorp is committed to boosting vehicle electrification as part of our pursuit of a net-zero emissions future. From electrifying advanced logistics and freight operations to powering electric tractors and school buses to supporting car sharing programs for low-income communities, PacifiCorp's innovative customer grants, rebates and partnerships are helping electrify the transportation sector in the West.

<u>Co-creating energy solutions for the grid of the future</u>
PacifiCorp's award-winning ***watt***smart® battery program relies on a growing fleet of residential and commercial batteries to enable greater use of renewable power and improve overall grid resilience. Together, customers' 2,400 batteries help PacifiCorp dispatch renewable energy from batteries to maintain grid stability and reduce peaks in demand. Program participants can access backup power for emergencies and earn monthly credits on their energy bills.

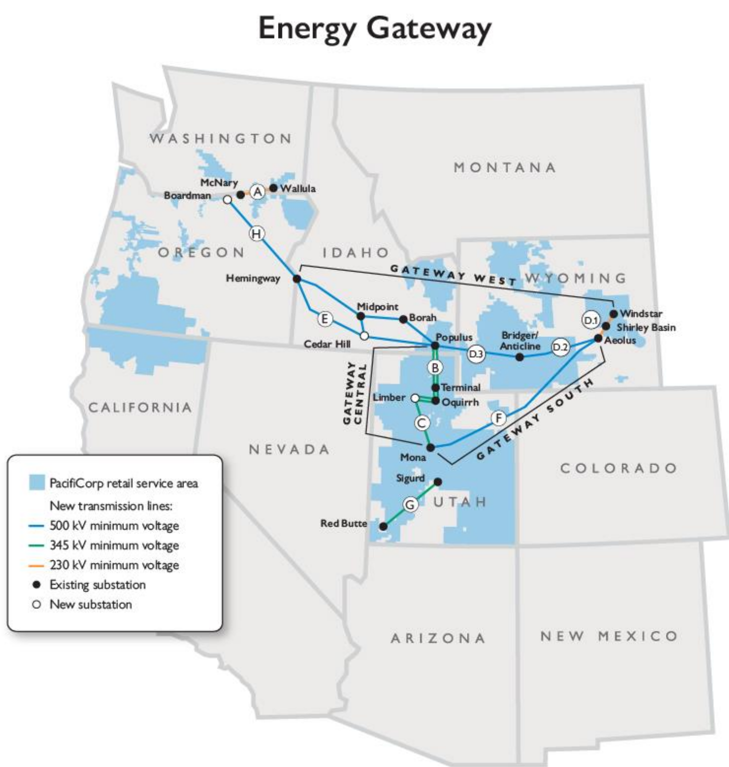
The company is also helping interconnect 64 megawatts of solar resources through the Oregon Community Solar Program. These projects provide an easy way for all customers to share in the benefits of local solar energy production.

<u>Planning for innovative storage resources</u>
PacifiCorp launched feasibility studies of 11 pumped hydroelectric storage projects located in Utah, Wyoming, Oregon, Idaho and Washington. Pumped hydroelectric storage has distinct advantages, including longer plant lives and significantly greater energy delivery capabilities when compared to other resource solutions. The company is pursuing permit applications with federal regulators to advance these projects.

<u>Partnering for advanced nuclear</u>
We're working with TerraPower, as part of a public-private partnership with the U.S. Department of Energy, to support the development of advanced nuclear reactors with integrated salt storage projects near retiring coal plants, laying the foundation for a future of non-carbon energy while supporting skilled jobs. In the 2023 IRP, the Natrium™ demonstration project is envisioned for placement at the Naughton facility in Kemmerer, Wyoming. With recent federal legislation and studies on the opportunities of a coal-to-nuclear energy transition, TerraPower and PacifiCorp remain committed to bringing the Natrium technology to market for the benefit of grid reliability and stability and for energy-producing communities in Wyoming and Utah.

Building a connected, resilient grid

Expanding transmission to connect clean energy and communities across the West
For the region and nation, this is a historic time that calls for prudent investments at a transformative scale. We are rising to meet this moment by expanding and modernizing the West's energy infrastructure – expeditiously, safely and in the most cost-effective way possible.



This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.

We're interconnecting the West by adding 2,500 miles of new transmission lines through the Energy Gateway transmission expansion plan. This initiative provides greater access to the West's abundant and diverse energy resources and is the foundation for our plan to meet our customers' expectations for an affordable and reliable net-zero energy future.

Regional leadership delivers opportunities
These are big-picture investments that only PacifiCorp can make, while keeping costs as low as possible and ensuring reliability. We are unique due to our scale, partnerships and integration throughout the West.

We own and operate one of the largest privately-held transmission systems in the nation, spanning 17,100 line miles of high-voltage transmission across 10 states with diverse resource capabilities. This makes us uniquely able to serve our customers with a broad portfolio of energy resources – at lower prices, with less risk of energy interruptions and with more resilience in the face of extreme weather.

The investments we're making now are essential in this moment, and they will help lower costs in the long term.

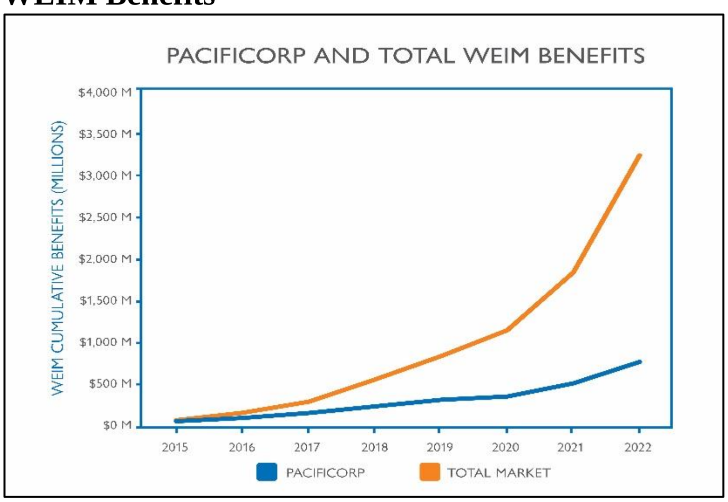
Capturing savings and delivering value

Pioneering advanced energy markets for reduced emissions, improved reliability and lower costs
We are moving the West forward by helping develop advanced energy markets that reduce emissions, improve reliability and keep costs low, through the power of diverse resources and collaboration with partners.

WESTERN ENERGY IMBALANCE MARKET

One of these advanced markets is already producing significant benefits for customers and the environment – the Western Energy Imbalance Market. This is a real-time wholesale energy market that brings together 20 utilities across the region to automatically dispatches the lowest-cost energy to meet the short-term needs of customers in 10 Western states and one Canadian province. The WEIM has saved PacifiCorp customers more than $591 million to date, while helping improve reliability and reduce emissions.

WEIM Benefits



EXTENDED DAY-AHEAD MARKET

We've recently taken another big step forward by helping lead the creation of the Extended Day-Ahead Market. The EDAM will do even more to enhance reliability, increase customer savings and reduce emissions throughout our region.

The EDAM will allow PacifiCorp to buy or sell wholesale electricity the day before it's needed – at a time when key fuel supply and operational commitments are made. Region-wide, EDAM member utilities will be able to work together across state lines and service areas to acquire clean, reliable power at the lowest cost. This will help reduce emissions and maintain a reliable, resilient power supply year-round, including during extreme weather events.

Energy Efficiency/Demand response

Expanded conservation measures
Energy efficiency and demand-response programs are important tools for meeting customers' future energy needs. Our innovative approach moves beyond management based on peak loads and focuses on turning demand-response resources into dynamic operating reserves. That's why we're expanding existing demand-response programs and introducing new solutions for customers, particularly as more interconnected technologies enter the market. These programs will reduce our need to buy reserve power on the market and create greater customer benefits.

In the coming years, our ongoing conservation and cost-effective demand-response initiatives will seek to deliver:

799 megawatts of energy efficiency between 2023 and 2026
372 megawatts of demand response between 2023 and 2026

Conclusion

Building a connected future for all our communities
Our 2023 IRP is a story of progress toward ambitious goals, one that offers clarity about the scope and scale of the work that lies ahead.

By continuing to work closely with the communities we serve, and by making prudent investments in innovation to accelerate necessary transformation, we will continue our progress toward a future of net-zero energy that delivers reliable, clean, safe, affordable power for generations to come.

PacifiCorp's Integrated Resource Plan Approach

In the 2023 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity maintaining substantial investment in energy efficiency and demand response programs.

At the same time, the preferred portfolio is responsive to the rapidly expanding arena of new state and federal regulatory requirements, most notably the federal Inflation Reduction Act and expansion of the Ozone Transport Rule. All of this can be achieved by maintaining reliable service with incremental investments in transmission infrastructure and other non-emitting flexible resources capable of shaping and responding to changes in energy from an increasing supply of wind and solar resources.

The primary objective of the IRP is to identify the best mix of resources to serve customers in the future. The best combination of resources is determined through analysis that measures cost and risk. The least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly the longer-range elements, can and do change over time. PacifiCorp's 2023 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public-input process began with the first public-input meeting in February 2022. Over the subsequent year, PacifiCorp met with stakeholders and hosted eighteen online public-input meetings. The transition to online public meetings occurred smoothly and efficiently in the face of COVID safety protocols. Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2023 IRP.

As depicted in Figure 1.1, PacifiCorp's 2023 IRP was developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio-development process. The portfolio-development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system. The resource portfolios produced for the 2023 IRP were created considering a wide range of potential coal and natural gas retirement dates, options to convert to gas or to retrofit for carbon capture utilization and sequestration for certain coal units, options to install selective catalytic reduction or selective non-catalytic reduction technologies and other planning uncertainties.

PacifiCorp then developed variants of the top performing resource portfolio to further analyze impacts of specific resource actions within the top performing portfolio. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure the comparative cost, risk, reliability, and emission levels. This resource portfolio analysis ultimately informed selection of the least-cost and least-risk portfolio, the 2023 IRP preferred portfolio and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were also done to produce specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp's 2023 IRP Approach

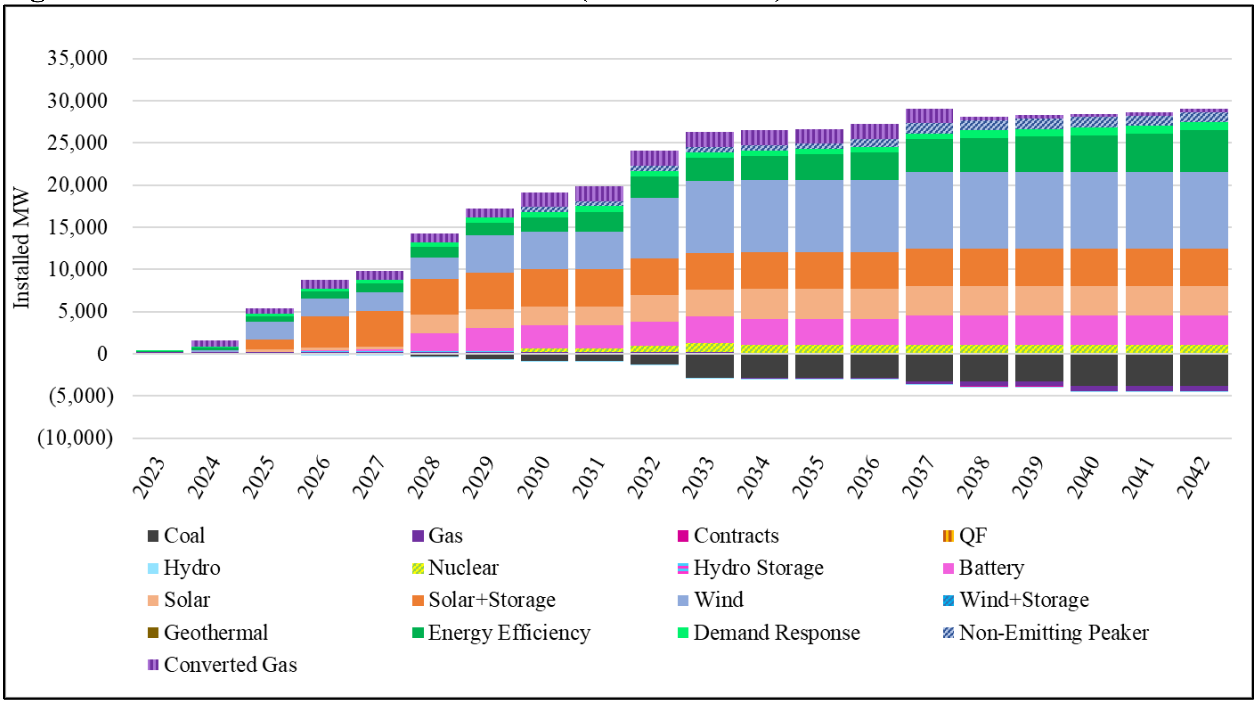
Preferred Portfolio Highlights

PacifiCorp's selection of the 2023 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 1.2 shows that PacifiCorp's 2023 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, advanced nuclear, and non-emitting peaking resources.

The 2023 IRP preferred portfolio includes new resources from the 2020 All-Source Request for Proposals (RFP). These projects include 1,792 MW of wind, 495 MW of solar additions with 200 MW of battery storage capacity. These resources will come online in the 2024-to-2025 timeframe. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River I (50 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2023 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022AS RFP is currently soliciting and evaluating resources to fulfill.

The 2023 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. By the end of 2032, the preferred portfolio includes 1,000 MW of additional advanced nuclear resources, and through 2037, the preferred portfolio includes1,240 MW of non-emitting peaking resources. Advancement of these two technologies will be critical to the planned transition of our coal resources in a way that will minimize impacts to our employees and our communities. Over the 20-year planning horizon, the 2023 IRP preferred portfolio includes 9,114 MW of new wind and 7,855 MW of new solar.

Figure 1.2 – 2023 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the 2023 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2023 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59-mile, high-voltage (230-kilovolt) transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.

The 2023 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway ("B2H"), which connects the Longhorn substation near the town of Boardman in Oregon to the Hemingway substation in Idaho, which will come online in 2026. By exchanging certain transmission assets with Idaho Power Company, PacifiCorp will receive additional transmission rights between Hemingway and the Populus substation in Idaho, which is closely tied to existing and future PacifiCorp transmission connecting to Utah and Wyoming. At the Oregon end of the B2H line, additional transmission upgrades are planned to connect B2H to growing loads.

New since the 2021 IRP, the 2023 IRP preferred portfolio includes a 200-mile high-voltage 500-kilovolt transmission line from Anticline substation in central Wyoming to Populus substation in southeastern Idaho known as Energy Gateway West Sub-Segment D.3, planned to come online in 2028.

Further, the 2021 IRP preferred portfolio included near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to serve our customers. New for the 2023 IRP, many of these transmission upgrades and the accompanying resources reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. By evaluating all newly proposed resource additions in an area at the same time, the cluster study process identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. As a result, many of the transmission upgrades and resource additions in the first five years of the IRP preferred portfolio reflect cluster study requests submitted in the past two years. Additional transmission expansion projects can include development of new segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest) and could include interconnections or partnerships with other utilities. Table 1.1 and Table1.2 summarizes the incremental transmission projects in the 2023 IRP preferred portfolio.

Table 1.1 – Transmission Projects Included in the 2023 IRP Preferred Portfolio 2023-2026[1,2]

Year		From	To	Export (MW)[1]	Import (MW)[1]	Inter-connect (MW)	Description
2024		Multistate Path C Improvement		0	0	100	Path C enables Utah, Idaho, Wyoming interconnection, additional transmission options
		Within Yakima WA Transmission Area		0	0	80	Union Gap-Midway 230 kV Line and substation - Yakima, enables additional transmission options
2025		Within Willamette Valley WA Transmission Area		0	0	9	Cluster 2 Area 22 - Willamette Valley, enables 9 MW of solar
		Walla Walla WA	Yakima WA	400	400	200	Walla Walla - Wine Country 230 kV line and integration, enables 200 MW of wind in 2032
	GWS	Wyoming East	Clover UT	1,200	1,700	2,030	Energy Gateway South, enables 1,716 MW wind, 315 MW solar and storage, and future transmission
2026		Within Borah-Populus ID Transmission Area		0	0	1,100	Cluster 2 Area 5 - Borah, enabling 1,100 MW solar and 1,100 MW storage
		Within BPA NITS (OR) Transmission Area		0	0	160	Cluster 2 Area 21 - BPA NITS, enables 160 MW storage
		Within Central Oregon Transmission Area		0	0	240	Transition Cluster Area 8 - Central Oregon, enables 200 MW solar and 200 MW storage
		Within Clover UT Transmission Area		0	0	331	TCA4: Q820 contingent facilities - Utah South, enables 300 MW solar and 300 MW storage
		Within Willamette Valley OR Transmission Area		0	0	719	Cluster 2 Area 23 - Willamette Valley, enables 474 MW solar and 474 MW storage
		Within Yakima WA Transmission Area		0	0	450	Cluster 1 Area 10 - Yakima, enables 450 MW solar and 707 MW storage
	B2H	Borah-Populus ID	Hemingway ID	600	300	600	B2H - Idaho Power Asset Transfer, enabling 300 MW wind, 400 MW solar, 600 MW storage
		Hemingway ID	Longhorn OR	818	0	0	B2H component
		Longhorn OR	McNary OR	300	0	0	B2H - Longhorn Load component
		Walla Walla WA	Borah ID	300	0	0	B2H - IPC PTP Eastbound component

Table1.2 – Transmission Projects Included in the 2023 IRP Preferred Portfolio 2027-2042[1,2]

Year	From	To	Export (MW)[1]	Import (MW)[1]	Inter-connect (MW)	Description
2027	Within Walla Walla WA Transmission Area		0	0	733	Cluster 2 Area 15 - Walla Walla, enabling 100 MW wind, 483 MW solar, 628 MW storage
2028	Within Yakima WA Transmission Area		0	0	180	230 kV Union Gap-Pomona Heights, prerequisite of Union Gap-Wine Country part b
2028	Jim Bridger WY	Borah-Populus ID	1,621	1,621	357	Segment D3, Transition Cluster Area 1, enables 357 MW wind
2029	Within Goshen ID Transmission Area		0	0	662	Transition Cluster 5/Cluster 1 Area 3 - Goshen, enables 200 MW wind and 549 MW storage
2029	Wyoming East	Jim Bridger WY	950	950	1,209	D2.2/D1.2, Cluster 1 Area 1, enables 1815 MW of wind
2029	D3 – Utah North	Borah-Populus ID	1,000	600	0	D3 supporting projects (west), enabled by D3
2029	D3 – Wyoming East	Jim Bridger WY	728	728	298	D3 supporting projects (east), enables 298 MW wind
2030	Within Utah North Transmission Area		0	0	558	Path C improvements: mostly 138 kV, enables 300 MW wind and 606 MW non-emitting peaker
2032	Within Portland North Coast Transmission Area		0	0	130	Birdsdale 230-115 kV and Portland 115 kV reinforcement, enables 130 MW wind
2032	Within Yakima WA Transmission Area		0	0	100	230 kV Union Gap-Wine Country part b, enables 500 MW wind
2033	Southern Oregon	Central Oregon	389	389	935	Del Norte-Central Oregon 500kV[2], enables 1,382 MW wind and 303 MW non-emitting peaker
2037	Walla Walla WA	Willamette Valley WA	30	30	12	500 kV Walla Walla-S.Lebanon and Reinforcement[2], facilitates regional transmission

[1] TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

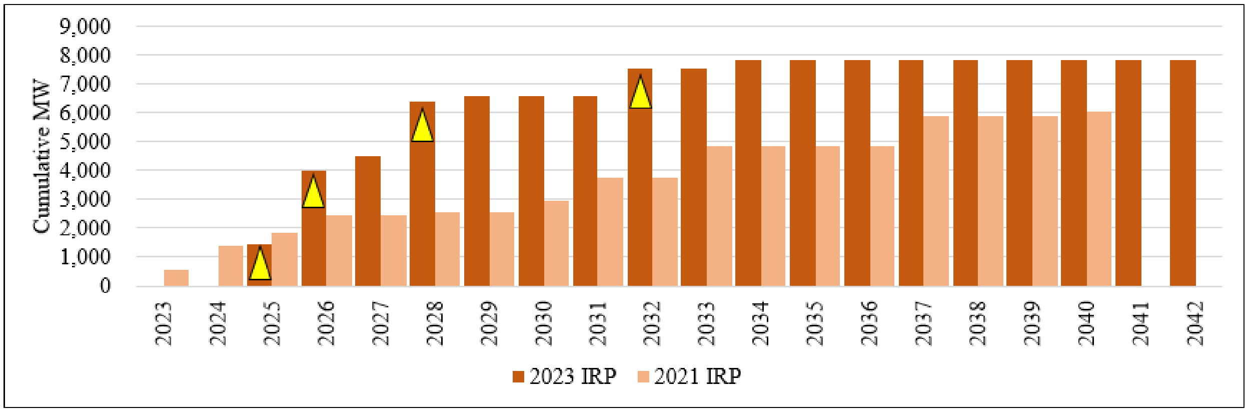
[2] Transmission upgrades are generally modeled as all or nothing options. These items reflect partial transmission builds, which were allowed in the second half of the 2023 IRP planning horizon, starting in 2033, so as to provide an indication of possible future outcomes.

As noted earlier, sensitivity analysis performed in the 2023 IRP that evaluates the impacts of significant new loads coming online in the 2033 timeframe support continuing with permitting support Energy Gateway segments and initiating preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional transmission expansion segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest).

New Solar Resources

The 2023 IRP preferred portfolio includes 3,993 MW by the end of 2025, more than 6,200 MW by the end of 2027, and more than 7,800 MW of new solar is online by the end of 2031, as shown in Figure 1.3.

Figure 1.3 – 2023 IRP Preferred Portfolio New Solar Capacity*

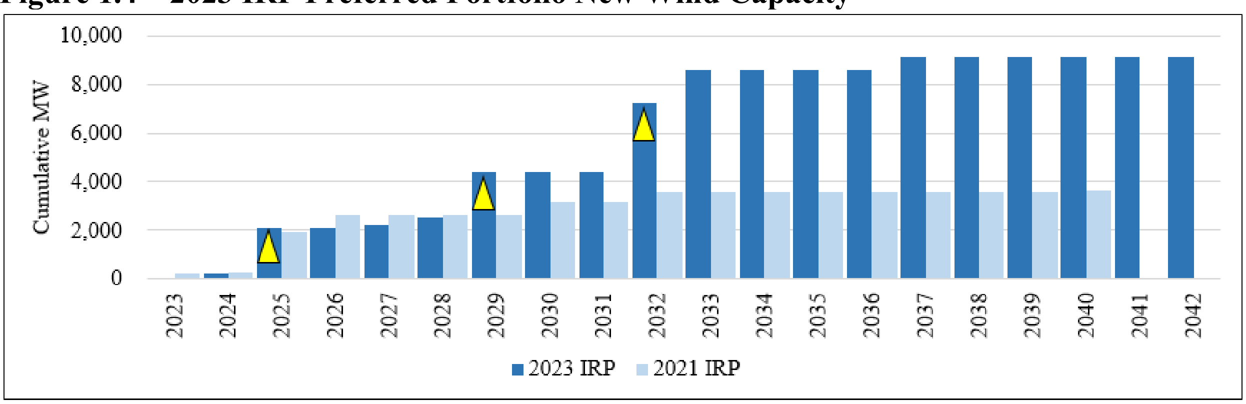


* 2023 IRP solar capacity shown in the figure includes solar resources coming via the 2020 All-Source Request for Proposals by the end of 2024. Resources are shown in the first full year of operation (the year after the year-online dates).

New Wind Resources

As shown in Figure 1.4, by year-end 2024, PacifiCorp's 2023 IRP preferred portfolio includes 2,131 MW of new wind generation resulting from the 2020 AS RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). By year-end 2028, the 2023 IRP preferred portfolio includes an additional 2,300 MW of new wind, and more than 7,200 MW of cumulative new wind by the end of 2031.

Figure 1.4 – 2023 IRP Preferred Portfolio New Wind Capacity*

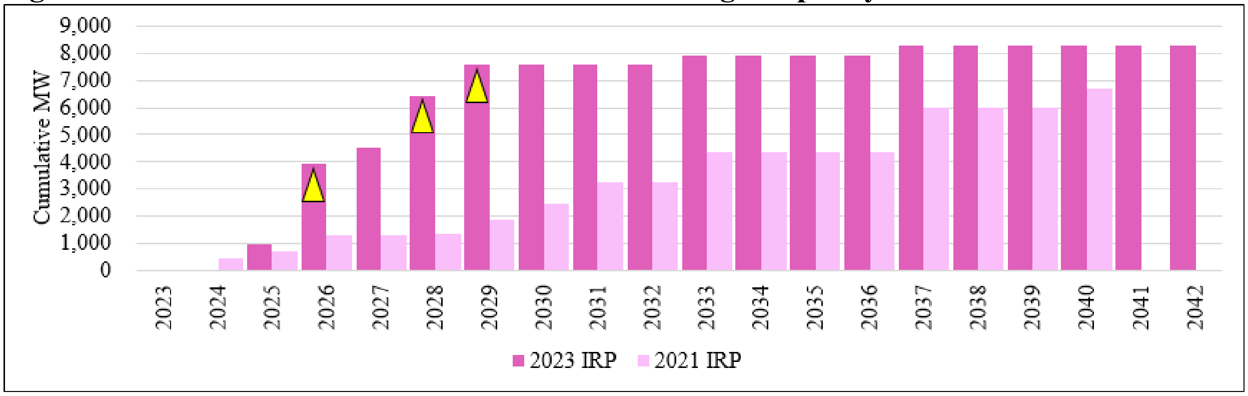


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates).

New Storage Resources

New storage resources in the 2023 IRP preferred portfolio are summarized in Figure 1.5. The 2023 IRP preferred portfolio presents a quickly escalating curve for storage selections in years 2023 through 2029, and includes over 3,900 MW by the end of 2025 – the majority of which is expected to be collocated with renewable resources by proxy selection or is paired with solar resources resulting from the 2020 All-Source RFP. By year-end 2028, the 2023 IRP includes nearly 7,600 MW of storage, comprised of 7,560 MW of proxy lithium ion battery storage and 35 MW of pumped hydro. 150 MW of long-duration storage appears by year-end 2032 and another 200 MW by the end of 2036.

Figure 1.5 – 2023 IRP Preferred Portfolio New Storage Capacity*

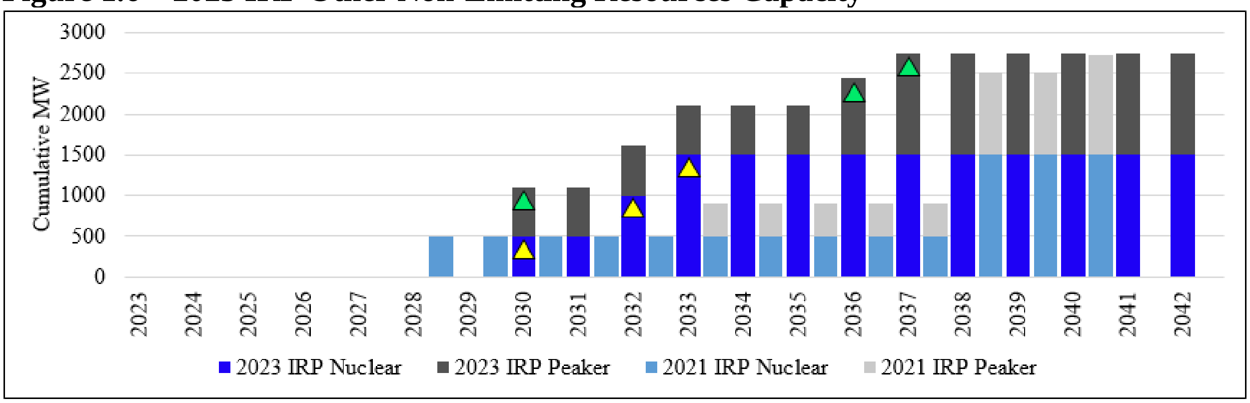


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Other Non-Emitting Resources

The 2023 IRP includes new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. As shown in Figure 1.6, the 500 MW advanced nuclear Natrium™ demonstration project is scheduled to come online by summer 2030. By year-end 2032, the 2023 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources. The 2023 IRP also includes 606 MW of non-emitting peaking resources by year-end 2029, increasing to 1,240 MW by the end of 2036. The advancement of these new technologies are critical to the planned transition of PacifiCorp's coal fleet.

Figure 1.6 – 2023 IRP Other Non-Emitting Resources Capacity*

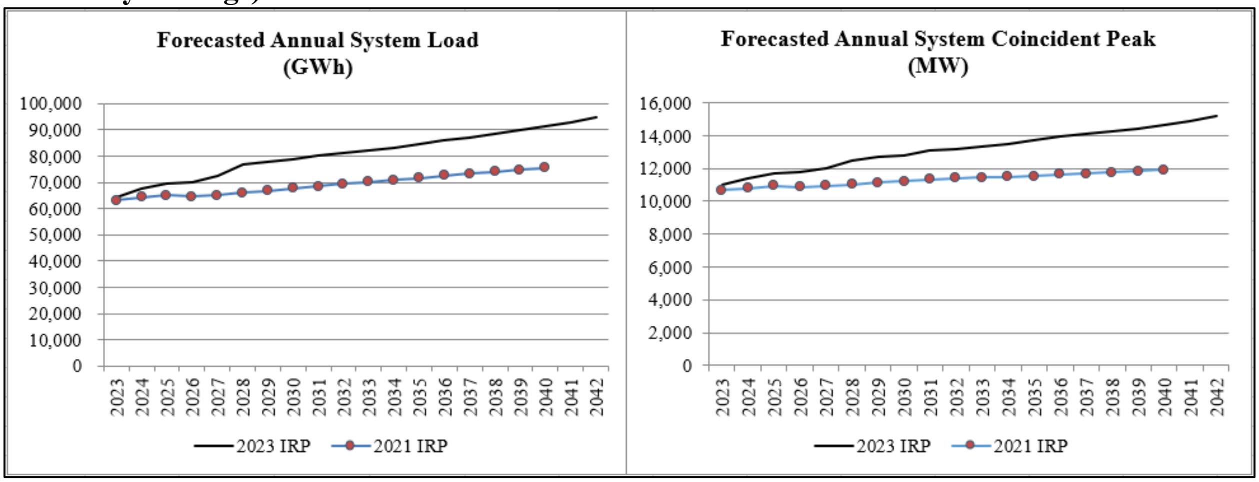


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 1.7 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2021 IRP. On average, forecasted system load is up 14.9 percent and forecasted coincident system peak is up 14.9 percent when compared to the 2021 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.07 percent for load and 1.70 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from new large customers driving up the commercial forecast and an increased residential forecast.

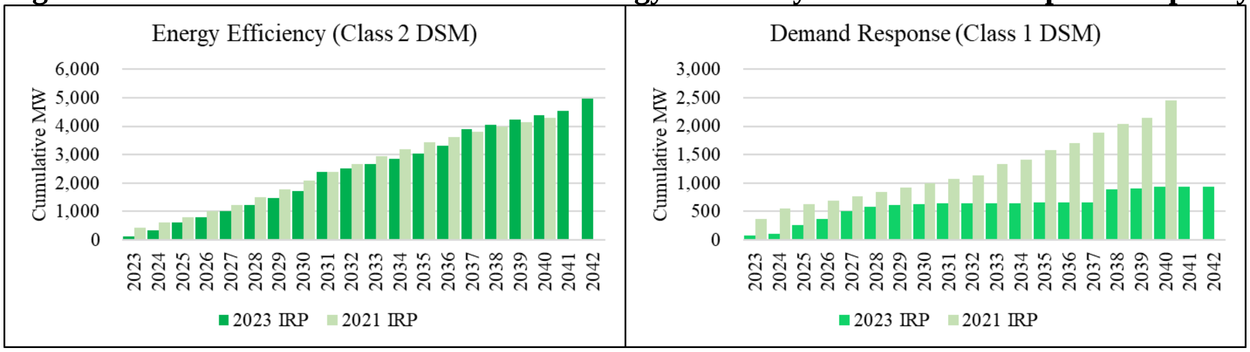
Figure 1.7 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 1.8 compares total energy efficiency capacity savings in the 2023 IRP preferred portfolio relative to the 2021 IRP preferred portfolio and includes 4,953 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 1.8 compares cumulative demand response program capacity in the 2023 IRP preferred portfolio relative to the 2021 IRP preferred portfolio and does not include capacity from existing programs. The 2023 IRP has a cumulative capacity of demand response programs reaching 929 MW by 2042 which represents a 264% decrease relative to the 2021 IRP. This decrease is the result of improved accounting for demand response resources and their potential overlap with one another. In the 2021 IRP, resources from the 2021 DR RFP were modeled concurrently with CPA resources to evaluate all possible resources. The result was an upper theorical maximum of resources that did not account for overlap in end-uses and programs.

Figure 1.8 – 2023 IRP Preferred Portfolio Energy Efficiency and Demand Response Capacity



Wholesale Power Market Prices and Purchases

Figure 1.9 shows that the 2023 IRP's base case forecast for natural gas prices has increased along with an increase in wholesale power prices for most years relative to those in the 2021 IRP. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The higher power prices observed in the 2023 IRP are primarily driven by the assumption of higher natural gas prices than what was assumed in the 2021 IRP. Wholesale power prices are higher in 2023 to 2030 due to weather conditions, higher inflation impacting new resource costs, and market volatility until the market settles. Moreover, the 2023 IRP assumed higher natural gas prices than the 2021 IRP due to impacts by world events notably including the war in Ukraine. Henry Hub in particular, is impacted by higher natural gas demand increasing liquefied natural gas exports. While not shown in the figure below, the 2023 IRP also evaluated low and high price scenarios when assessing the cost and risk of different resource portfolios.

Figure 1.9 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

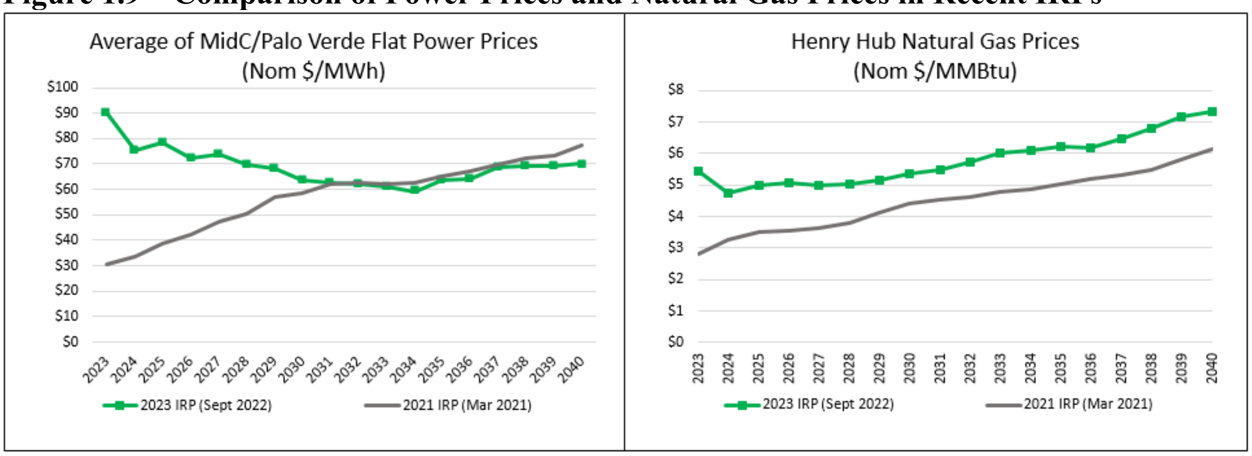
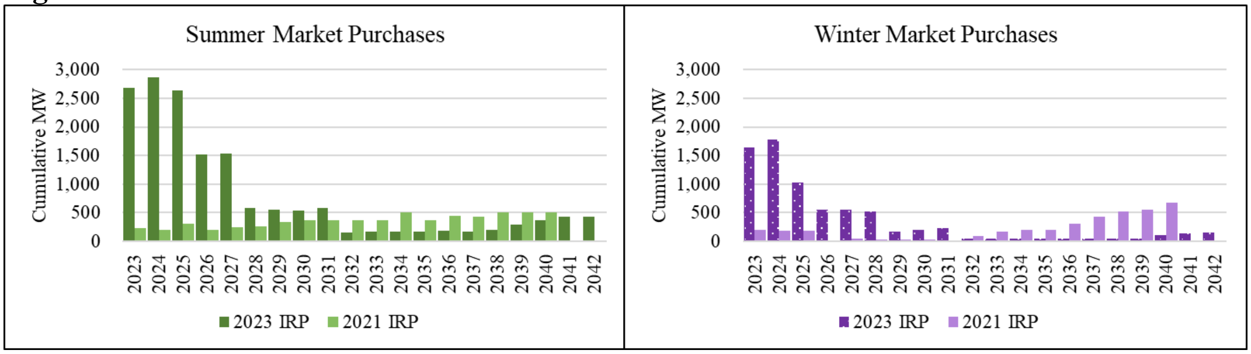


Figure 1.10, below, shows an overall increase in reliance on wholesale power market firm purchases in the 2023 IRP preferred portfolio relative to the wholesale power market purchases included in the 2021 IRP preferred portfolio. In years 2023 through 2027, the magnitude of this increase is exaggerated due to the accounting of purchases to meet near-term load obligations in the 2021 IRP, where additional purchases could have been assumed to meet deficiencies. While wholesale power market purchases are higher in 2028 through 2031 compared to the 2021 IRP, purchases are relatively less through the remaining ten years of the planning period, driven largely by the influx of cost-effective renewable energy and investments in new technology that support

the planned transition for PacifiCorp's coal fleet. PacifiCorp is actively participating in regional efforts to develop day-ahead markets and a resource adequacy program that will help unlock regional diversity and facilitate market transactions over the long term.

Figure 1.10 – 2023 IRP Preferred Portfolio Market Purchases



*Note: In the 2021 IRP, higher near-term market purchases were represented by system shortfalls that were assumed to be avoided through market purchases disallowed in the model. In the 2023 IRP this methodology was enhanced to represent the coverage of these shortfalls as market purchases, declining steadily over the next several years as new resource additions, and particularly battery storage, come online.

Coal and Gas Exits, Retirements, and Gas Conversions

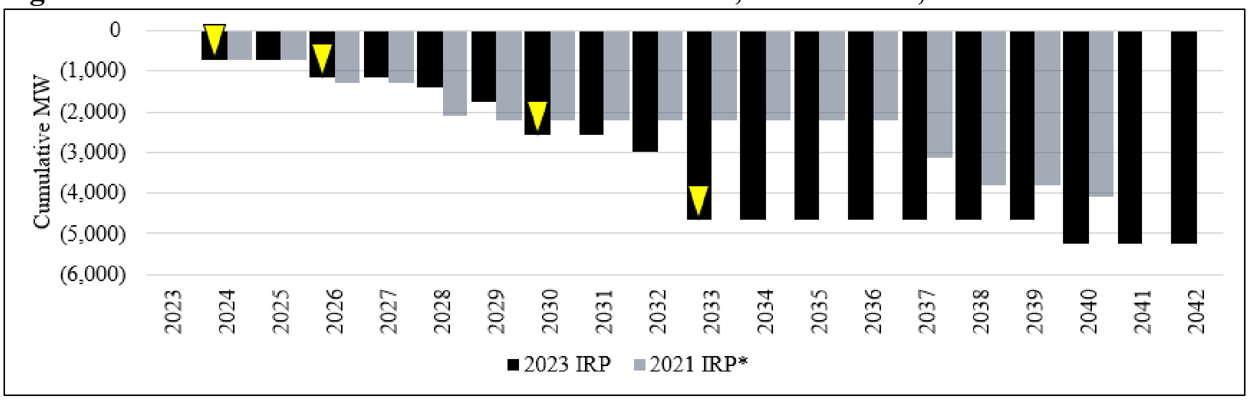
Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement or gas conversion of 13 units by 2030 and 20 units by year-end 2032. The final two coal units retire by 2039, or three years ahead of the end of the planning period, with the path to decarbonization supported by new non-emitting technologies. As shown in Figure 1.11, coal unit retirements/gas peaker conversions in the 2023 IRP preferred portfolio will reduce coal-fueled generation capacity by 1,153 MW by the end of 2025, and over 2,999 MW by 2032.

Coal unit exits, retirements, and gas conversions scheduled under the preferred portfolio include:

- 2023 = Jim Bridger Units 1-2, converted to natural gas in 2024 (same as in the 2021 IRP)
- 2025 = Craig Unit 1 retirement (same as in the 2021 IRP)
- 2025 = Colstrip Unit 3 exit (same as in the 2021 IRP)
- 2026 = Naughton Units 1-2, converted to natural gas in 2026, operates through 2036 (retired 2025 in the 2021 IRP)
- 2027 = Dave Johnston Units 3 retirement (same as in the 2021 IRP)
- 2027 = Hayden Unit 2 retirement (same as in the 2021 IRP)
- 2028 = Dave Johnston Units 1-2 retirement (retired 2027 in the 2021 IRP)
- 2028 = Craig Unit 2 retirement (same as in the 2021 IRP)
- 2028 = Hayden Unit 1 retirement (same as in the 2021 IRP)

- 2029 = Colstrip Unit 4 exit, Colstrip Unit 3 share is consolidated into Colstrip Unit 4 in 2025 (retired 2025 in the 2021 IRP)
- 2030 = Jim Bridger Units 3-4, converted to natural gas in 2030, operates through 2037 (retired 2037 without conversion in 2021 IRP)
- 2031 = Hunter Unit 1 retirement, SNCR installed 2026 (outside of 2021 IRP planning horizon, retiring 2042)
- 2032 = Hunter Units 2-3 retirement, SNCR installed 2026 (outside of 2021 IRP planning horizon, retiring 2042)
- 2032 = Huntington Units 1-2 retirement, SNCR installed 2026 (retired 2036 in 2021 IRP)
- 2039 = Dave Johnston Unit 4 retirement (retired 2027 in 2021 IRP)
- 2039 = Wyodak retirement, SNCR installed 2026 (retired 2039 without SNCR in 2021 IRP)

Figure 1.11 – 2023 IRP Preferred Portfolio Coal Exits, Retirements, and Gas Conversions*



* Note: Coal exits and retirements are assumed to occur by the end of the year before the year shown in the graph. The graph shows the year in which the capacity will not be available for meeting summer peak load. All figures represent PacifiCorp's ownership share of jointly owned facilities.

In addition to the coal unit exits, retirements, and gas conversions outlined above, the preferred portfolio reflects 2,660 MW natural gas retirements through 2042. This includes Gadsby at the end of 2032, Naughton Units 1, 2, and 3 at the end of 2036, Hermiston at the end of 2036, and Jim Bridger Units 1, 2, 3, and 4 at the end of 2037.

Carbon Dioxide Emissions

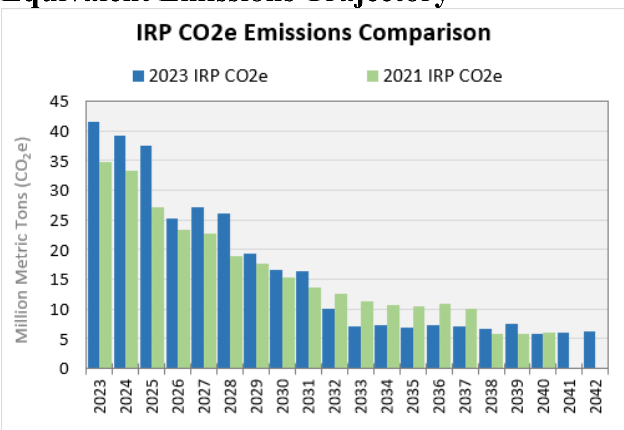
The 2023 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) and other carbon dioxide equivalent (CO_2e) emissions resulting in a measure of total emissions. PacifiCorp's emissions have been declining and continue to decline related to several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new non-emitting resources, storage, transmission, Regional Haze compliance that capitalizes on flexibility, and the Ozone Transport Rule.

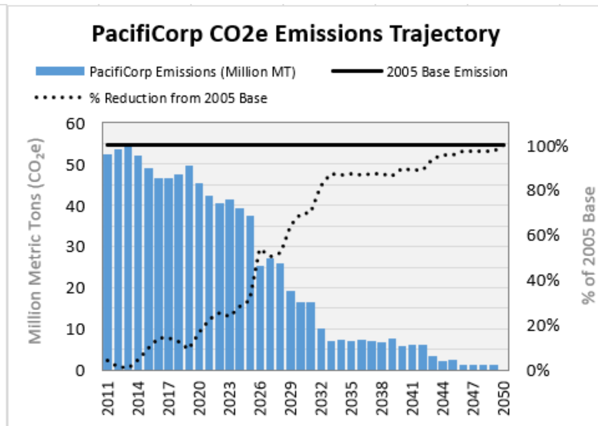
The chart on the left in Figure 1.12 compares projected annual CO_2e emissions between the 2023 IRP and 2021 IRP preferred portfolios. In this graph, emissions are assigned to market purchases.

In the current 2023 IRP emissions are higher than projected in the 2021 IRP until 2032, this is a result of higher load forecast in the 2023 IRP. By 2032, average annual CO_2e emissions are down 21 percent relative to the 2021 IRP preferred portfolio. By 2040 emissions are comparable to the 2021 IRP while generation has increased by 31% showing that the overall emissions rate is lower under 2023 IRP portfolio. By the end of the planning horizon, system CO_2e emissions are projected to fall from 41.5 million metric tons in 2023 to 6.2 million tons in 2042—a reduction of 85 percent.

The chart on the right in Figure 1.12 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, of 54.6 million metric tons, system CO_2 equivalent emissions are down 31 percent in 2025, 70 percent in 2030, 87 percent in 2035, 89 percent in 2040, 96 percent in 2045, and 100 percent in 2050.

Figure 1.12 – 2023 IRP Preferred Portfolio CO_2 Equivalent Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory*





*Note: PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2022 from owned facilities, specified sources and unspecified sources. From 2023 through the end of the twenty-year planning period in 2042, emissions reflect those from the 2023 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2042, emissions reflect the rolling average emissions of each resource from the 2023 IRP preferred portfolio through the life of the resource or the end of the contract. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be discussed in more detail in Oregon's Clean Energy Plan.

Renewable Portfolio Standards

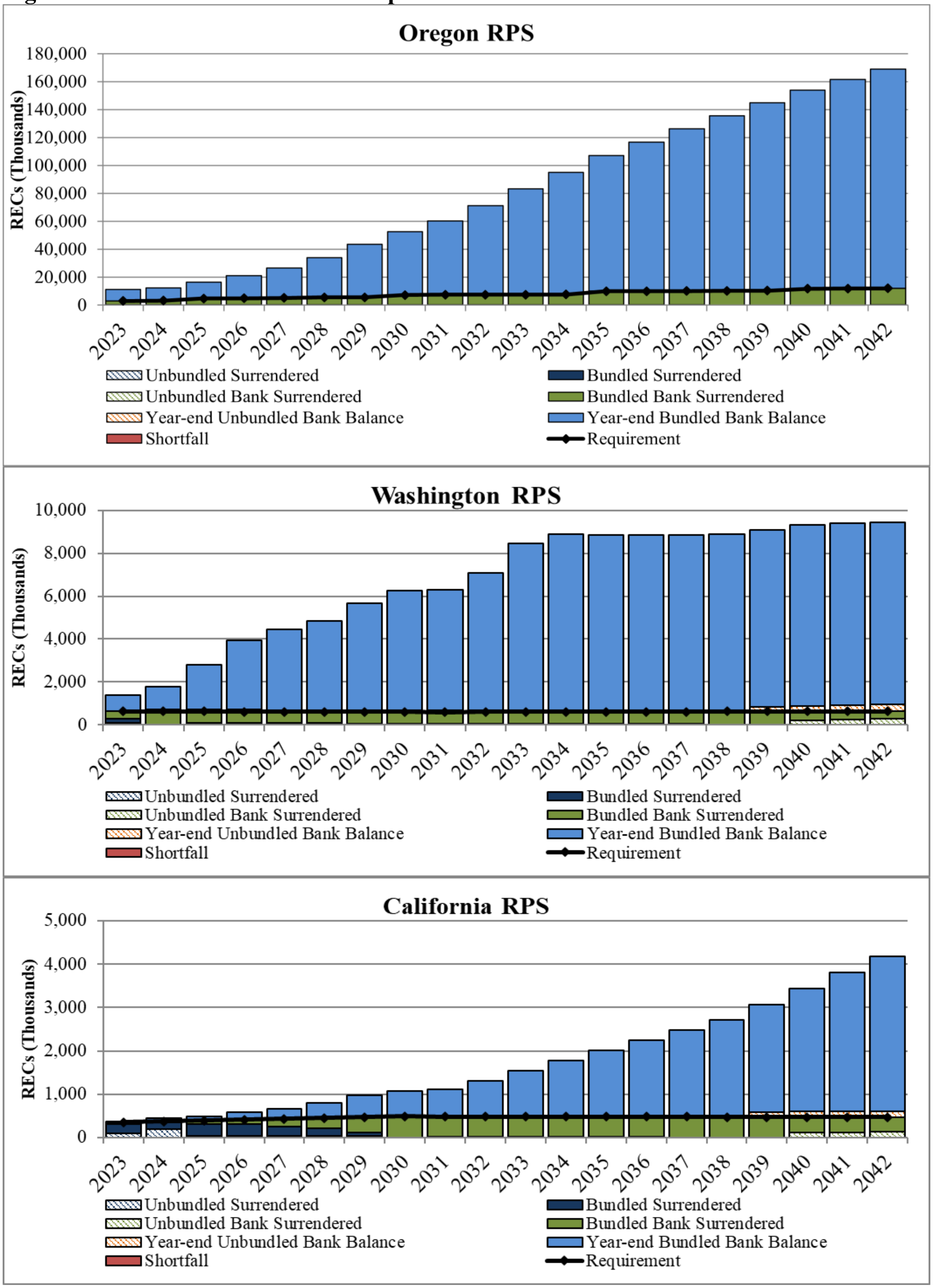
Figure 1.13 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2042 with the addition of new renewable resources in the 2023 IRP preferred portfolio. Washington RPS compliance is also achieved through 2042 with the addition of new renewable resources. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington receives a system share of renewable resources across PacifiCorp's system.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as REC purchases throughout the 2023 IRP study period. The ramping RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in the near term. New renewable resources in the 2023 IRP preferred portfolio mitigate that shortfall, but the company is seeking to purchase approximately 200,000 RECs in the near term.

While not shown in Figure 1.13, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources and transmission in the 2023 IRP preferred portfolio.

Figure 1.13 – Annual State RPS Compliance Forecast



2023 IRP Advancements and Supplemental Studies

IRP Advancements

During each IRP planning cycle, PacifiCorp identifies and implements advancements to continuously improve the IRP for its customers, other stakeholders, and regulatory commissions. Some of the key advancements implemented in the 2023 IRP include:

- Advancement of the Plexos Modeling System
  As part of its 2023 IRP, PacifiCorp continued to leverage its use of advanced third-party software to conduct its long-term capacity expansion modeling, hourly dispatch simulations of resource portfolios and stochastic modeling. PacifiCorp implemented the Plexos modeling system by Energy Exemplar in the 2021 IRP. The three platforms of the Plexos tool (referred to as Long-term (LT), Medium-term (MT) and Short-term (ST)) work on an integrated basis to inform the optimal combination of resources by type, timing, size, and location over PacifiCorp's 20-year planning horizon. The Plexos tool also allows for improved endogenous modeling of resource options simultaneously, greatly reducing the volume of individual portfolios needed to evaluate impacts of varying resource decisions. See further information below and also see Volume I, Chapter 8 (Modeling and Portfolio Evaluation) for more information.

- Endogenous Modeling of Resources
  In the prior IRP, the Plexos model was able to endogenously consider coal retirement timing options along with other specified options such as gas conversion or carbon capture utilization and sequestration retrofit for a coal unit. In the 2023 IRP this endogenous treatment of coal has been improved by allowing for each unit to be retired in any appropriate year rather than only in a discrete set of individual years. In addition, for the first time, PacifiCorp's 2023 IRP endogenously considered natural gas resource retirements in its capacity expansion modeling. Also, the endogenous modeling of transmission was enhanced to leverage cluster study data to inform the amounts, types and locations of proxy resources so as to align better with probable near-term projects and their transmission dependencies. Endogenous transmission modeling capabilities include the consideration of 1) new incremental transmission options tied to resource selections, 2) existing transmission rights tied to the use of post-retirement brownfield sites, and 3) incorporation of costs associated with these transmission options, and 4) transmission options that interact with multiple or complex elements of the IRP transmission topology. Endogenous modeling of standalone and collocated battery resources was also improved with the Plexos model over the 2021 IRP. In the 2021 IRP, Plexos allowed for the endogenous treatment of the entirety of battery optimization. An additional enhancement made in the 2023 IRP was to allow standalone battery to be built in any location and not subject to an installed capacity limit. This aligns with the current interconnection realities provided by PacifiCorp Transmission. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) for more information.

- Targeted Portfolio Reliability Analysis
  In the 2023 IRP, PacifiCorp further advanced its approach for assessing the reliability of resource portfolios and the ability of each unique resource portfolio to meet reliability requirements. This IRP continues to incorporate operating reserves in the LT model for capacity expansion and optimizes available resources to meet requirements in all periods, not just the system peak. With significant levels of economic renewable resource being selected in

every resource portfolio, PacifiCorp found that subsequent modeling of these resource portfolios using the Short-Term (ST) hourly dispatch model, which considers more granularity and an explicit accounting of operating reserve requirements, consistently identified capacity shortfalls needed to maintain reliable operation of the system. PacifiCorp ran 20-year ST studies to evaluate shortfalls on a portfolio-specific basis across each year of the 20-year planning horizon. From the results of these hourly deterministic ST runs PacifiCorp developed a process to remedy the incremental need for reliability resources through cost-effective resource additions to a portfolio to ensure there is sufficient flexible capacity to meet reliability requirements. The reliability assessment process has been improved by expanding storage availability, but also through the addition of new storage options, including 8-hour and higher capacity lithium ion, 100-hour iron-air batteries and flow batteries. Also, this process was improved by leveraging the storage availability and updated tax law to allow for expanded options related to collocated resources. Whereas the 2021 IRP only allowed for collocation of battery storage with solar resources, the 2023 IRP allows for collocation of battery storage with any resource type, increasing effective capacity of renewables and allowing for more effective timing dispatch. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) for more information.

- Reporting Improvements
  In the 2023 IRP, in response to stakeholder feedback and IRP commitments stemming from the 2021 IRP, PacifiCorp enhanced its reporting to enable a broader range of publicly available workpapers, and to allow for more stakeholders to access confidential workpapers by creating a "highly-confidential" category to capture materials of particular commercial sensitivity. PacifiCorp also leveraged its new RFP price-scoring methodology as a part of its reporting, building upon work done to determine the net value of every resource in each portfolio. The 2023 IRP also makes available workpapers used to translate hourly model output into resource selections for reliability, flexibility and cost-effectiveness. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) for more information.

- Stakeholder Requests and Feedback
  In its 2023 IRP, in addition to PacifiCorp's stakeholder feedback form process of posting the forms received from stakeholders as well as PacifiCorp's response throughout the public-input process, PacifiCorp has also summarized the stakeholder feedback forms received and how feedback was considered as part of the 2023 IRP document. PacifiCorp received and responded to 38 stakeholder feedback forms in the 2023 IRP along with follow-up discussions upon request. PacifiCorp was able to accommodate numerous stakeholder requests to run additional variant studies over and above PacifiCorp's originally planned variants. In total 19 variant studies were contemplated in competition for the preferred portfolio, compared to 8 variants modeled in the 2021 IRP. Among the added studies are variants for Cluster study outcomes, offshore wind, selective catalytic reduction, natural gas alternatives and additional coal retirement strategies. A full summary of requests received and considered can be found in Volume II, Appendix C (Public Input Process).

- Public-Input Meetings
  PacifiCorp began its public-input process for the 2023 IRP development cycle in February of 2022. In response to stakeholder feedback, the first two meetings incorporated many topics two-to-three months earlier in the process relative to prior IRP cycles. This was accomplished by integrating the first several meetings with the development cycle for the Conservation Potential Assessment which has previously preceded the official IRP kick-off in May. As a

result, stakeholders were given the opportunity to participate much earlier in the development process for topics such as supply-side resources, the 2023 IRP cycle overview, two planning environment updates, the 2021 IRP fling status, and a Plexos/optimization modeling primer. In response to stakeholder feedback and direction from Utah Staff and Commission, materials provided for public input meetings were also provided a minimum of three days in advance of each meeting. This sometimes resulted in presenting less material at any given meeting but allowed for advanced review by stakeholders of materials that were presented. See Volume II, Appendix C (Public Input) for more information.

Supplemental Studies

PacifiCorp's 2023 IRP relies on numerous supplemental studies that support the derivation of specific modeling assumptions critical to development of its long-term resource plan. A description of these studies, discussed in more detail in appendices filed with the 2023 IRP, is provided below. Additional source files and information may also be located for some studies on PacifiCorp's IRP webpage at the following location:
www.pacificorp.com/energy/integrated-resource-plan.html

- Capacity Contribution
  The capacity contribution of a resource is dependent on the other components in a portfolio, and PacifiCorp's portfolio development process is based on achieving reliable system operation using the aggregate contributions of each resource in the portfolio, rather than focusing on an individual estimate. For reporting, the capacity factor approximation method (CF Method) is used to identify marginal capacity contribution values for individual resource options, based on a portfolio similar to the preferred portfolio. For additional information on capacity, see Chapter 6 (Load and Resource Balance).

- Conservation Potential Assessment
  An updated conservation potential assessment (CPA) prepared by Applied Energy Group (commissioned by PacifiCorp) and the Energy Trust of Oregon was prepared to develop DSM resource potential and cost assumptions specific to PacifiCorp's service territory. The CPA supports the cost and DSM savings data used during the portfolio-development process.

- Energy Storage Potential Evaluation
  Energy storage resources can provide a variety of grid services since they are highly flexible, with the ability to respond to dispatch signals and act as both a load and a resource. This evaluation, refreshed for the 2023 IRP, provides details on these grid services and on how energy storage resources can be configured and sited to maximize the benefits they provide.

- Flexible Reserve Study
  This study, updated for the 2023 IRP, evaluates the need for flexible resources resulting from the variability and uncertainty in load, wind, solar, and other generation resources. The study produces an estimate of flexible reserve needs for each hour that accounts for the specific load, wind, and solar resources being evaluated. Reserve costs associated with meeting these flexible reserve needs are also estimated.

- Plant Water Consumption Study
  This study provides updated data on the water consumption of PacifiCorp-owned generating facilities by fuel type and by state in which the facility is located.

- Private Generation Resource Assessment
  This supplemental study, prepared by DNV, was refreshed for the 2023 IRP to produce updated private generation penetration forecasts for solar photovoltaic, small-scale wind, small-scale hydro, combined heat and power reciprocating engines, and combined heat and power micro-turbines specific to PacifiCorp's service territory. The report includes updates relevant to the Inflation Reduction Act. The private generation penetration forecasts from this study are applied as a reduction to forecasted load throughout the IRP modeling process and used in developing assumptions for the low private generation sensitivity and high generation sensitivity cases.

- Smart Grid
  PacifiCorp has included an update on its Smart Grid efforts with a focus on transmission and distribution systems and customer information.

- Stochastic Parameter Update
  PacifiCorp's preferred portfolio-selection process relies, in part, on stochastic risk analysis using Monte Carlo random sampling of stochastic variables. Stochastic variables include natural gas and wholesale electricity prices, load, hydro generation, and unplanned thermal outages. For the 2023 IRP, PacifiCorp updated its stochastic parameter input assumptions with more current historical data.

- Renewable Resources Assessment
  A study on renewable resources and energy storage was commissioned to support PacifiCorp's 2023 Integrated Resource Plan (IRP). The "2023 Renewable IRP", prepared by WSP, is screening-level in nature and includes a comparison of technical capabilities, capital costs, and operations and maintenance costs that are representative of renewable energy and storage technologies. WSP evaluated energy storage options of On-shore and Off-shore wind, Compressed Air Energy Storage, Lithium-Ion Battery, Flow Battery, Gravity Storage, as well as wind and solar and combinations of these resource types.

Action Plan

The 2023 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2023 IRP public-input process. Table 1.3 details specific 2023 IRP action items by resource category.

Table 1.3 – 2023 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**<u>Colstrip Units 3 and 4:</u>** • PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030.
1b	**<u>Craig Unit 1:</u>** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP preferred portfolio target exit date of December 31, 2025.
1c	**<u>Naughton Units 1 and 2:</u>** • PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**<u>Jim Bridger Units 1 and 2 Gas Conversion:</u>** • PacifiCorp has initiated the process of ending coal-fueled operations. The Wyoming Air Quality Division issued an air permit on December 28, 2022, for the natural gas conversion. All required regulatory notices and filings will be completed by end of 2023. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.

<table>
<tr><td>1e</td><td><u>Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:</u>
PacifiCorp will complete evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023.
PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024.</td></tr>
<tr><td>1f</td><td><u>Regional Haze Compliance:</u>
Following the resolution of first planning period regional haze compliance disputes, and the EPA’s determination of the states’ second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units.
PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.</td></tr>
<tr><td>1g</td><td><u>Natrium™ Demonstration Project:</u>
PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable.
By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project.
By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders.
By 2027, PacifiCorp will begin training operators.
PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.</td></tr>
<tr><td>1h</td><td><u>Ozone Transport Rule Compliance:</u>
PacifiCorp will assess the impact of EPA’s finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP.
PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective.
Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023.</td></tr>
</table>

Action Item	2. New Resource Actions
2a	**<u>Customer Preference Request for Proposals:</u>** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2023, which may necessitate issuance of a request for proposals to procure resources within the action plan window.
2b	**<u>2024 All-Source Request for Proposals:</u>** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the 2023 IRP preferred portfolio that can achieve commercial operations by the end of December 2028. • In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier.

2c	**<u>2022 All-Source Request for Proposals:</u>** • In April 2022 PacifiCorp issued an all-source Request for Proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2027. • In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for any applicable significant energy resources on final shortlist. PacifiCorp will file certificate of public convenience and necessity (CPCN) applications, as applicable, and • By Q4 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the 2022 all-source RFP are expected to achieve commercial operation by December 31, 2027, or earlier.

Action Item	3. Transmission Action Items
3a	**<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>** • In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service.
3b	**<u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u>** • In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service.
3c	**<u>Boardman-to-Hemingway (500 kV transmission line):</u>** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in "pre-construction" activities in support of the 2026 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids
3e	Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>4a</td><td>

<u>Energy Efficiency Targets:</u>

- PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP.
- PacifiCorp will pursue cost-effective energy efficiency resources as summarized in the table below:

Year	Annual 1st Year Energy (GWh)	Annual Incremental Capacity (MW)
2023	543	123
2024	551	220
2025	596	259
2026	563	197

- PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity[1] selections from the preferred portfolio[2] as summarized in the table below:

Year	Annual Incremental Capacity (MW)
2023	72
2024	39
2025	152
2026	109

[1] Capacity impacts for demand response include both summer and winter impacts within a year.
[2] A portion of cost-effective demand response resources identified in the 2023 preferred portfolio in 2023 for Oregon and Washington represent planned volumes expected are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources offered through approved programs. subsequently procured under the previously issued RFP in compliance with state level procurement requirements.

</td></tr>
</table>

Action Item	5. Market Purchases
5a	**<u>Market Purchases:</u>** • Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

Action Item	6. Renewable Energy Credit (REC) Actions
6a	**<u>Renewable Portfolio Standards (RPS):</u>** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2024 and future compliance periods, as needed.
6b	**<u>Renewable Energy Credit Sales:</u>** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

CHAPTER 2 – INTRODUCTION

PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. This IRP fulfills the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. It was developed through a collaborative public input process with involvement from regulatory staff, advocacy groups, and other interested parties. As the owner of the IRP and its action plan, all policy judgments and decisions concerning the IRP are ultimately made by PacifiCorp considering its obligations to its customers, regulators, and shareholders.

PacifiCorp's selection of the 2023 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 1. shows that PacifiCorp's 2023 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, advanced nuclear, and non-emitting peaking resources.

The 2023 IRP preferred portfolio includes new resources from the 2020 All-Source Request for Proposals (RFP). These projects include 1,792 MW of wind, 495 MW of solar additions with 200 MW of battery storage capacity. These resources will come online in the 2024-to-2025 timeframe. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River I (50 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022AS RFP is currently soliciting and evaluating resources to fulfill.

The 2023 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Through 2033, the 2023 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources, and through 2037, the preferred portfolio includes1,240 MW of non-emitting peaking resources. Advancement of these two technologies will be critical to the planned transition of our coal resources in a way that will minimize impacts to our employees and our communities. Over the 20-year planning horizon, the 2023 IRP preferred portfolio includes 9,114 MW of new wind and 7,855 MW of new solar.

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes the construction of a 416-mile 500-kilovolt (kV) transmission line known as Gateway South connecting southeastern Wyoming and northern Utah, the 59-mile 230 kV transmission line in eastern Wyoming known as Gateway West Segment D.1, and the 500 kV, 290-mile transmission line across eastern Oregon and southwestern Idaho known as Boardman to Hemingway (B2H). Additional projects and details are described in Volume I, Chapter 1 (Executive Summary), Chapter 4 (Transmission), and Chapter 9 (Modeling and Portfolio Selection Results).

Other significant studies conducted to support analysis in the 2023 IRP include:

- An updated demand-side management resource conservation potential assessment;
- A private generation study for PacifiCorp's service territory;

- A renewable resources assessment;
- A flexible reserve study;
- An updated plant water consumption study;
- An energy storage potential evaluation;
- An assessment of smart grid technologies;
- Updated stochastic parameters; and
- An updated load and resource balance.

This chapter outlines the components of the 2023 IRP, summarizes the role of the IRP, and provides an overview of the public-input process.

2021 Integrated Resource Plan Components

The basic components of PacifiCorp's 2023 IRP include:

- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities; Volume I, Chapter 3 (Planning Environment)
- Description of PacifiCorp's transmission planning efforts and activities; Volume I, Chapter 4 (Transmission).
- Discussion of PacifiCorp's commitment to serve customers reliably, and summary of the company's actions to ensure all-weather resource adequacy, wildfire mitigation planning, and transmission planning to support power flow reliability; Volume I, Chapter 5 (Reliability and Resiliency)
- Load and resource balance on a capacity and energy basis and determination of the load and energy positions for the front ten years of the twenty-year planning horizon; Volume I, Chapter 6 (Load and Resource Balance).
- Profile of resource options considered for addressing future capacity and energy needs; Volume I, Chapter 7 (Resource Options).
- Description of IRP modeling, including a description of the portfolio development process, cost and risk analysis, and preferred portfolio selection process; Chapter 8 (Modeling and Portfolio Evaluation)
- Presentation of IRP modeling results and selection of PacifiCorp's preferred portfolio; Volume I, Chapter 9 (Modeling and Portfolio Selection Results) .
- Presentation of PacifiCorp's 2023IRP action plan linking the company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource procurement risks; Volume I, Chapter 10 (Action Plan).

The IRP appendices, included as a Volume II, contain the items listed below:

- Load Forecast (Volume II, Appendix A),
- Regulatory Compliance (Volume II, Appendix B),
- Public Input (Volume II, Appendix C),
- Demand-Side Management (Volume II, Appendix D),
- Smart Grid (Volume II, Appendix E),
- Flexible Reserve Study (Volume II, Appendix F),

- Plant Water Consumption Study (Volume II, Appendix G),
- Stochastic Parameters (Volume II, Appendix H),
- Capacity Expansion Results (Volume II, Appendix I)
- Stochastic Simulation Results (Volume II, Appendix J),
- Capacity Contribution (Volume II, Appendix K),
- Private Generation Study (Volume II, Appendix L),
- Renewable Resources Assessment (Volume II, Appendix M),
- Energy Storage Potential Evaluation (Volume II, Appendix N),
- Washington Clean Energy Transformation Act (Volume II, Appendix O)
- Acronyms (Volume II, Appendix P)

PacifiCorp is also providing data discs for the 2023 IRP. These discs support and provide additional details for the analysis described within the document. Data discs are generated for public, confidential and highly confidential data to be provided as appropriate to each recipient. Confidential and highly confidential data access are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings. "Highly confidential" is a new category to be used in the 2023 IRP adopted to allow the company to provide the maximum amount of access to parties who are not participants in commercial developments as well as those who have direct conflicts of interest regarding commercially sensitive information.

The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP establishes a plan that will deliver adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[1] In this way, the IRP serves as a roadmap for determining and implementing PacifiCorp's long-term resource strategy. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting request for proposal bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

Public-Input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public-input process allowing stakeholder involvement in all phases of plan development. PacifiCorp organized six state meetings and held 10 public-input meetings, some of which spanned two days to facilitate information sharing, collaboration, and expectations for the 2023 IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed.

Volume II, Appendix C (Public-Input Process) provides detail concerning the public-input process.

[1] The Public Utility Commission of Oregon and Public Service Commission of Utah cite "long-run public interest" as part of their definition of integrated resource planning. Public interest pertains to adequately quantifying and capturing for resource evaluation any resource costs external to the utility and its ratepayers. For example, the Public Service Commission of Utah cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decision-making process.

In addition to the public-input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and stakeholder input throughout the IRP process. The IRP webpage can be found at the following location: www.pacificorp.com/energy/integrated-resource-plan.html, an e-mail "mailbox" (irp@pacificorp.com). Additionally, a stakeholder feedback form was used to provide opportunities for stakeholders to submit additional input and ask questions throughout the 2023 IRP public-input process. The submitted forms, as well as PacifiCorp's responses to these feedback forms are located on the PacifiCorp's IRP website: www.pacificorp.com/energy/integrated-resource-plan/comments.html. A summary of stakeholder feedback forms received, and company response was provided during the public-input meetings.

CHAPTER 3 – PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- Federal and state tax credits continue to encourage the procurement of wind and solar resources, which will likely dominate U.S. capacity additions for the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, new storage technologies, and market design changes.
- The Federal Inflation Reduction Act (IRA) was enacted on August 16, 2022,, creating technology specific tax credits for projects placed in service after December 31, 2021, and technology neutral tax credits for projects placed in service after December 31, 2024. Eligible resources include and any technology that generates electricity and does not emit greenhouse gases. The IRA is modeled in all 2023 IRP studies.
- The Environmental Protection Agency (EPA) formally proposed the Ozone Transport Rule on April 6, 2022, and finalized the rule on March 15, 2023, pending publication in the Federal Register. This new rule is focused on the reduction of nitrogen oxides, precursors to ozone formation, and has been proposed to cover 22 states including, for the first time, Utah, Nevada and California. EPA has deferred a decision on Wyoming until December 2023.
- In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA), which requires that 100% of electricity sales in Washington be 100% renewable and non-emitting by 2045. PacifiCorp filed its first Clean Energy Action Plan for CETA in its 2021 IRP and laid the groundwork for CETA compliance in analysis based on the preferred portfolio. The Company filed its first Clean Energy Implementation Plan (CEIP) on December 30, 2021 and has refiled this document responsive to Washington Staff and stakeholder feedback in March 2023.
- In 2021, Washington passed the Climate Commitment Act, which establishes a cap-and-invest program that was implemented through the regulatory rulemaking process in 2022 and came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities are that are subject to CETA are allocated allowances commensurate with emissions associated with Washington retail load at no cost. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.
- In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. The 2023 IRP includes modeling to support House Bill 2021 which is expanded upon in PacifiCorp's first Oregon Clean Energy Plan submission, filed concurrently with the IRP.
- PacifiCorp and the California Independent System Operator Corporation (CAISO) launched the voluntary western energy imbalance market (WEIM) November 1, 2014, the first western energy market outside of California. Since inception, The WEIM's footprint has grown significantly, generating $3.4 billion in monetary benefits to customers of participating entities. ($1.42 billion total footprint-wide benefits as of August 2, 2021). A significant contributor to EIM benefits is transfers across balancing authority areas,

providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area. Building on the success of WEIM, in 2022 PacifiCorp, along with CAISO and other stakeholders, collaborated to develop a market design for an extended day ahead market (EDAM) that CAISO plans to launch in 2025.

- Near-term procurement activities focused on three areas—the purchase and sale of renewable energy credits, and the purchase or procurement of new renewable and energy storage resources, and the procurement of new demand response resources. PacifiCorp filed a 2022 all source request for proposals (2022AS RFP) and received approval in three states by Q2 2022 in order to issue the solicitation to the market on April 29, 2022. PacifiCorp bid twelve eligible self-build (benchmark) resources on December 2, 2022, and on March 14, 2023, PacifiCorp received 302 bids from 74 developers and 93 different projects sites across six states. A final shortlist is expected by late Q2 2023 or early Q3 2023 with resources contracted by the end of Q4 2023. PacifiCorp anticipates a similar all source RFP will be required as an action item out of this 2023 IRP.

Introduction

This chapter profiles the major external influences that affect PacifiCorp's long-term resource planning and recent procurement activities. External influences include events and trends affecting the economy, wholesale power and natural gas prices, and public policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Major issues in the power industry include resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). Future natural gas prices, the role of gas-fired generation, the roll of emerging technologies, and the declining net costs of renewables and battery technologies also play a role in the selection of the portfolio that best achieves least-cost, least-risk planning objectives.

On the government policy and regulatory front, a further significant issue in the power industry and facing PacifiCorp continues to be planning for eventual, but highly uncertain, climate change policies. This chapter provides discussion on climate change policies as well as a review of significant policy developments for currently regulated pollutants. This chapter also provides updates on the status of renewable portfolio standards and resource procurement activities.

Wholesale Electricity Markets

PacifiCorp's system operates in conjunction with a multifaceted market. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by ensuring that resources with the lowest operating cost are serving demand throughout the region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp actively participates in the wholesale market by making purchases and sales to minimize costs and to keep its supply portfolio in balance with customers' expectations. This interaction with the market takes place on time scales ranging from sub-hourly to years in advance.

Without the wholesale market, PacifiCorp – or any other load serving entity – would need to construct or own an unnecessarily large margin of supplies that would go unused in all but the most unusual circumstances and would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand.

The benefits of access to an integrated wholesale market have grown with the increased penetration of intermittent generation such as solar and wind. Intermittent generation can come online and go offline abruptly in congruence with changing weather conditions. Federal and state (where applicable) tax credits and improved technology performance have continued to place wind and solar resources "in the money" in areas of high potential. As such, wind and solar will continue to play a dominant role in power supply options over the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, evolving storage technologies, and market design changes.

Regarding transmission, there are long-haul, renewable-driven transmission projects in advanced development in the U.S. WECC. These transmission lines ultimately connect areas of high renewable potential and low population density to areas of high population density with less renewable potential. This includes PacifiCorp's proposed 416-mile high-voltage 500-kilovolt (kV) Gateway South project and the 59-mile high-voltage 230-kV Gateway West Segment D.1 project—both with an online date by the end of 2024. These transmission projects will provide greater system-wide flexibility transferring energy from Wyoming to load centers located in Utah.

Similarly, several transmission projects provide additional east-to-west transfer capability allowing greater integration of intermittent resources. Gateway West – a series of transmission projects currently in the permitting process that is partially in service as of 2022 – would add east-to-west transfer capability on PacifiCorp's system.[1] Boardman-to-Hemingway (B2H), a joint effort with Idaho Power Company, a 290-mile high-voltage 500-kilovolt transmission between the Hemingway substation in southwestern Idaho and the Pacific Northwest with an online date by the end of 2026. Additionally TransWest Express, while not a PacifiCorp development, is a 730-mile line high-voltage 500-kilovolt transmission line from southwest Wyoming through Colorado and Utah to Nevada's Hoover Dam is anticipated to begin construction in once the Bureau of Land Management issues a notice to proceed, with a projected online date in the mid-2020s.

The intermittency of renewable generation has also given rise to a greater need for fast-responding and long-duration storage, which is essential for grid stability and resiliency. Pumped storage has been the traditional storage option and there are multiple projects being developed throughout the West. Of remaining mechanical, thermal, and chemical storage options, lithium-ion (Li-ion) batteries have shown the most promise in terms of cost and performance. In 2013, the California Public Utility Commission (CPUC) required investor-owned utilities to procure 1,325 MW of storage by 2020; that requirement has been satisfied. As of 2022, nine states had implemented energy storage targets or mandates, with action being considered in at least one other.[2] In California, Pacific Gas & Electric (PG&E)'s Elkhorn Battery project became fully operational in April of 2022. This Moss Landing project in Monterey County includes 182.5 MW of Tesla

[1] Additional information on Gateway West projects can be found in Volume I, Chapter 4 (Transmission).
[2] California, New Jersey, New York, Massachusetts, Oregon, Nevada, Virginia, Connecticut, and Maine have either mandated or set energy storage targets, while Arizona is considering the implementation of targets.

Megapack energy storage.[3] Hybrid co-located solar photovoltaic (SPV) and battery systems are now in Utah, Hawaii, Arizona, Nevada, California, and Texas. In March 2019, Florida Power & Light Company announced a plan to build the world's largest solar-powered battery system with 409 MW of capacity, which was unveiled in December of 2021. The company has plans to install 30 million solar panels across the state of Florida by 2030, supported by energy storage.

In 2018, the Federal Energy Regulatory Commission (FERC) directed regional transmission organizations (RTO) and independent system operators (ISO) to develop market rules for the participation of energy storage in wholesale energy, capacity, and ancillary services markets[4]. The FERC gave operators nine months to file tariffs and another year to implement – essentially opening wholesale markets to energy storage. Operators' proposed tariffs have varied substantially among regions with PJM requiring a 10-hour continuous discharge capability while New England requires a continuous 2-hour capability. Later, in May 2019, the FERC issued an order generally affirming the earlier order to establish reforms to remove barrier to the participation of electric storage resources in certain organized wholesale markets. As part of its 2023 IRP, PacifiCorp is evaluating the cost effectiveness of several energy storage systems, including pumped storage, stand-alone Li-ion batteries, flow batteries, iron-air storage, and other long-duration storage, as well as energy storage co-located with generating resources.

Increased renewable generation has also contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the Energy Imbalance Market (EIM). The EIM became operational November 1, 2014, and as of August 2021 has seen NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, Powerex, Idaho Power, Balancing Authority of Northern California, Salt River Project, Seattle City Light, Los Angeles Department of Water and Power, Northwestern Energy, and Public Service Company of New Mexico join the EIM. Avista Utilities, Tucson Electric Power, Tacoma Power, and Bonneville Power Administration joined in 2022 with Avangrid Renewables, El Paso Electric, and Western Area Power Administration are planned to join in Spring 2023 . The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and five-minute dispatch. CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. As part of other EIM participating entities, PacifiCorp is also participating in the CAISO stakeholder process to establish and Extended Day-Ahead Market (EDAM), tentatively targeted to go-live in 2024

As with all markets, electricity markets face a wide range of uncertainties. In February 2021, winter storm Uri caused an unprecedented 24.1% decline in marketed natural gas production in Texas, a drop of 186.7 billion cubic feet (Bcf) compared to the previous month. This decline contributed to the largest monthly decline in natural gas production on record in the Lower 48 states. This weather

[3] In addition to Elkhorn, PG&E has contracts for more than 3,330 MW of battery storage being deployed statewide through 2024, more than 900 MW of which has been connected to California's electric grid. The Mercury News, March 8, 2023; [PG&E ushers in landmark Tesla battery energy storage system at Moss Landing (mercurynews.com)]
[4] 162 FERC ¶ 61,127 United States of American Federal Energy Regulatory Commission, 18 CFR Part 35 [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841] *Electric Storage Participation in Markets Operated by Regional Transmission;* Organizations and Independent System Operator (Issued February 15, 2018)

event caused widespread disruptions in energy supply and demand, including extended electric power blackouts in Texas.

The Western United States experienced an excessive heat event during the first week of September 2022. As a result, record temperatures were recorded on September 4th through September 7th, reaching as high as 114º F in Sacramento, California, 110º F in Burbank, California, and 107º F in Salt Lake City, Utah. With these record setting temperatures, the West saw a widespread surge in electricity demand and correspondingly tight supply conditions. Maintaining reliability across the region during this period was a testament to the benefits of energy markets, geographic diversity across the West, and conservation efforts during extreme heat events.

Market participants routinely study demand uncertainties driven by weather and overall economic conditions. The North American Electric Reliability Corporation (NERC) publishes an annual assessment of regional power reliability and any number of data services are available that track the status of new resource additions[5]. In December 2020, the NERC assessment indicated that WECC region has adequate resources through 2030. However, the NERC's probabilistic studies indicate that in each of the WECC's sub-regions' (except Alberta), resource adequacy was at risk during off peak hours, starting as early as 2021.[6]

The Western Resource Adequacy Program (WRAP)[7] will also provide market participants insight into potential supply constraints and give participants some assurance that sufficient resources have been procured for the program to maintain a 1-in-10-year loss of load expectancy standard. In addition to binding load and resource showings for the upcoming season, the WRAP will conduct advisory two- and five-year resource adequacy assessments for the footprint that will allow participants to better plan for the future needs of their systems. The Forward Showing program will ensure participants procure sufficient resources to meet a footprint wide reliability standard, and the Ops Program will facilitate transfers between entities in a resource deficit and those with excess resources.

In addition to reliability planning, there are externalities that can heavily influence the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Natural gas-fired generation and gas prices have been a critical determinant of western electricity prices, and this is expected to continue over the term of this plan's decision horizon. While the share of natural gas in the resource western resource mix is expected to fall by the end of the horizon as a result of increasing renewable resource buildout, natural gas will remain on the margin in many hours, particularly critical hours when renewable resource output is limited. Another critical uncertainty that weighs heavily on the 2023 IRP, as in past IRPs, is the uncertainty surrounding future greenhouse gas policies, both federal and/or state. PacifiCorp's official forward price curve (OFPC) does not assume a federal carbon dioxide (CO_2) policy, but other price scenarios developed for the IRP consider impacts of potential future federal and state policies

[5] 2020 Long-term Reliability Assessment, December 2020, North American Electric Reliability Assessment
[6] A discussion of regional resource adequacy efforts can be found in Volume I, Chapter 5 (Reliability and Resiliency)
[7] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

which drive additional costs and restrictions of emissions. However, PacifiCorp's OFPC does include enforceable state climate programs that have been signed into law[8].

Power Market Prices

Inflation, conflict in Eastern Europe, and global sanctions in 2022 caused supply shortages in the fossil gas market. As seen in Table 3.1 the shortage coupled with unseasonably high temperatures lead to an annually averaged 63% increase in on-peak spot prices across the Non-CAISO WECC trading hubs.

Table 3.1 - 2021 and 2022 Monthly Average On-Peak Prices

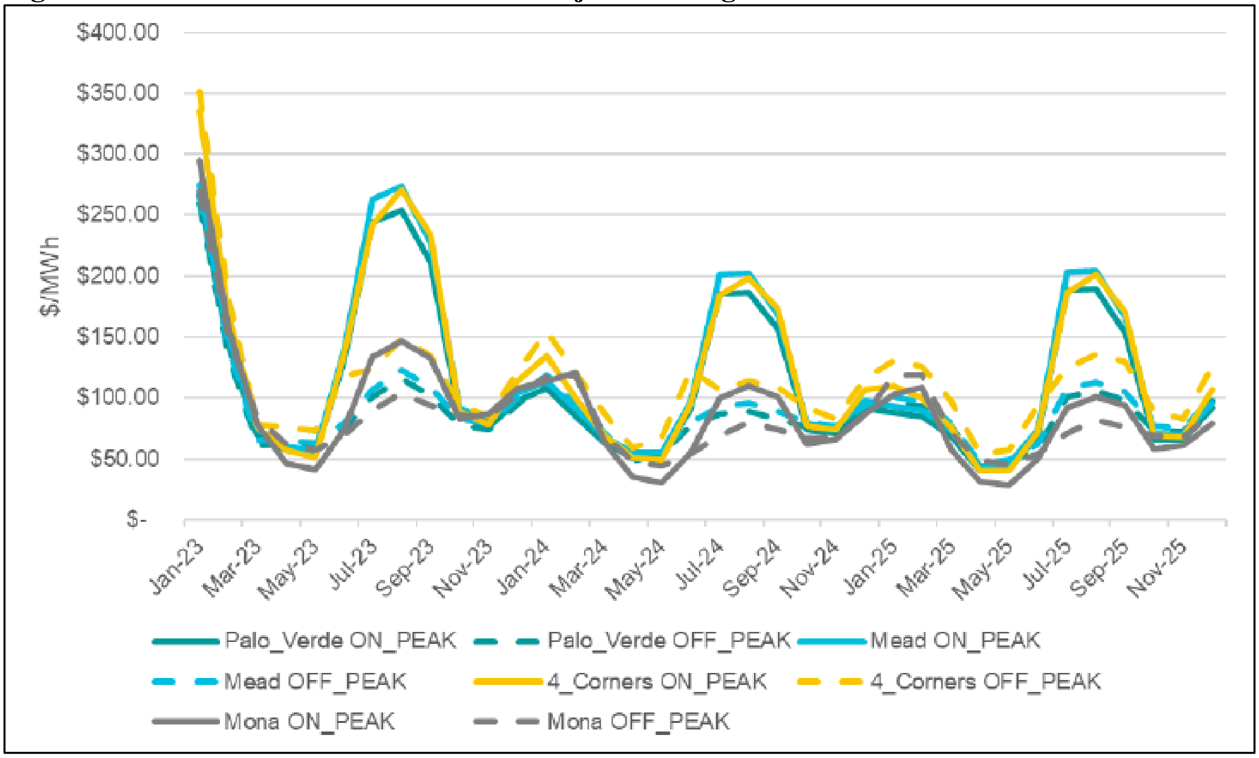
Month	2021	2022	Difference	Percent
Jan	$ 28.30	$ 45.24	$ 16.94	60%
Feb	$ 60.88	$ 42.59	$ (18.29)	-30%
Mar	$ 28.88	$ 37.32	$ 8.44	29%
Apr	$ 34.14	$ 66.16	$ 32.02	94%
May	$ 32.00	$ 61.20	$ 29.20	91%
Jun	$ 82.49	$ 57.27	$ (25.21)	-31%
Jul	$ 105.63	$ 81.46	$ (24.18)	-23%
Aug	$ 71.58	$ 117.22	$ 45.64	64%
Sep	$ 81.51	$ 210.23	$ 128.72	158%
Oct	$ 63.79	$ 71.06	$ 7.27	11%
Nov	$ 53.48	$ 88.49	$ 35.01	65%
Dec	$ 60.64	$ 267.91	$ 207.28	342%
Annual	$ 58.61	$ 95.51	$ 36.90	63%

Source: SNL

Barring major geo-political disruptions or other sustained economic drivers, forecasted wholesale power prices are expected to decline relative to 2022 peaks and will follow seasonal weather trends with higher prices over the summer months. Broker price spreads indicate August 2023 On-Peak power prices at Palo Verde, Mead, and Four Corners are trading around $250 per MWh while Mona is trading at $140.

[8] California and Washington carbon allowance price forecasts are applied when appropriate. Washington allowance prices assumed the forecast published by Vivid Economics, commissioned by Washington Department of Ecology as part of its CCA Regulatory Impact Analysis for WAC 173-446, which was the best available information at the time of modeling. Available at https://apps.ecology.wa.gov/publications/documents/2202047.pdf.

Figure 3.1 - Forward Prices at WECC Major Trading Hubs



Source: OTC, Siemens PTI

Table 3.2 reports the quarterly on-peak and off-peak price spread across the major WECC hubs, driving the peaks and valleys observed in Figure 3.1 above.

Table 3.2 - 2023-2025 Forward Price Spread

Date	Palo Verde		Mead		4 Corners		Mona	
	ON_PEAK	OFF_PEAK	ON_PEAK	OFF_PEAK	ON_PEAK	OFF_PEAK	ON_PEAK	OFF_PEAK
Jan-23	$ 266.32	$ 260.12	$ 275.26	$ 267.01	$ 335.12	$ 351.80	$ 294.68	$ 269.98
May-23	$ 53.58	$ 59.21	$ 57.05	$ 62.61	$ 50.66	$ 73.32	$ 41.04	$ 57.31
Aug-23	$ 254.31	$ 115.55	$ 273.46	$ 122.87	$ 270.55	$ 148.08	$ 146.25	$ 103.52
Nov-23	$ 75.82	$ 73.96	$ 80.74	$ 78.60	$ 78.37	$ 84.68	$ 87.06	$ 84.87
Jan-24	$ 107.54	$ 114.14	$ 113.39	$ 118.35	$ 134.67	$ 154.38	$ 113.84	$ 118.14
May-24	$ 51.50	$ 54.13	$ 55.19	$ 56.89	$ 48.74	$ 67.03	$ 30.44	$ 43.96
Aug-24	$ 186.45	$ 88.80	$ 202.10	$ 95.99	$ 198.36	$ 113.80	$ 109.51	$ 80.18
Nov-24	$ 71.13	$ 72.79	$ 76.06	$ 76.93	$ 73.53	$ 83.33	$ 66.30	$ 66.86
Jan-25	$ 88.00	$ 96.23	$ 93.11	$ 100.40	$ 110.14	$ 130.17	$ 102.82	$ 118.68
May-25	$ 42.54	$ 46.35	$ 45.71	$ 48.80	$ 40.23	$ 57.40	$ 28.02	$ 45.02
Aug-25	$ 189.13	$ 106.07	$ 204.32	$ 112.26	$ 201.18	$ 135.93	$ 100.89	$ 82.16
Nov-25	$ 65.99	$ 72.11	$ 70.12	$ 75.37	$ 68.21	$ 82.56	$ 61.04	$ 68.46

Source: OTC

Power Market Dynamics

Non-CAISO WECC Generation and Capacity Mix

The generation mix of the in the non-CAISO WECC region reflects the influence of individual state RPS and emissions policies. In 2022, hydro resources provided about 25% of generated energy followed by fossil gas at 25%, coal at 20%, and wind 13%. These numbers are projected to remain relatively stable through 2025. The annual share of energy fueled by coal generation is projected to decline despite fossil gas price shocks while new wind and solar capacity additions will increase their share of generation.

Figure 3.2 - National RPS Targets

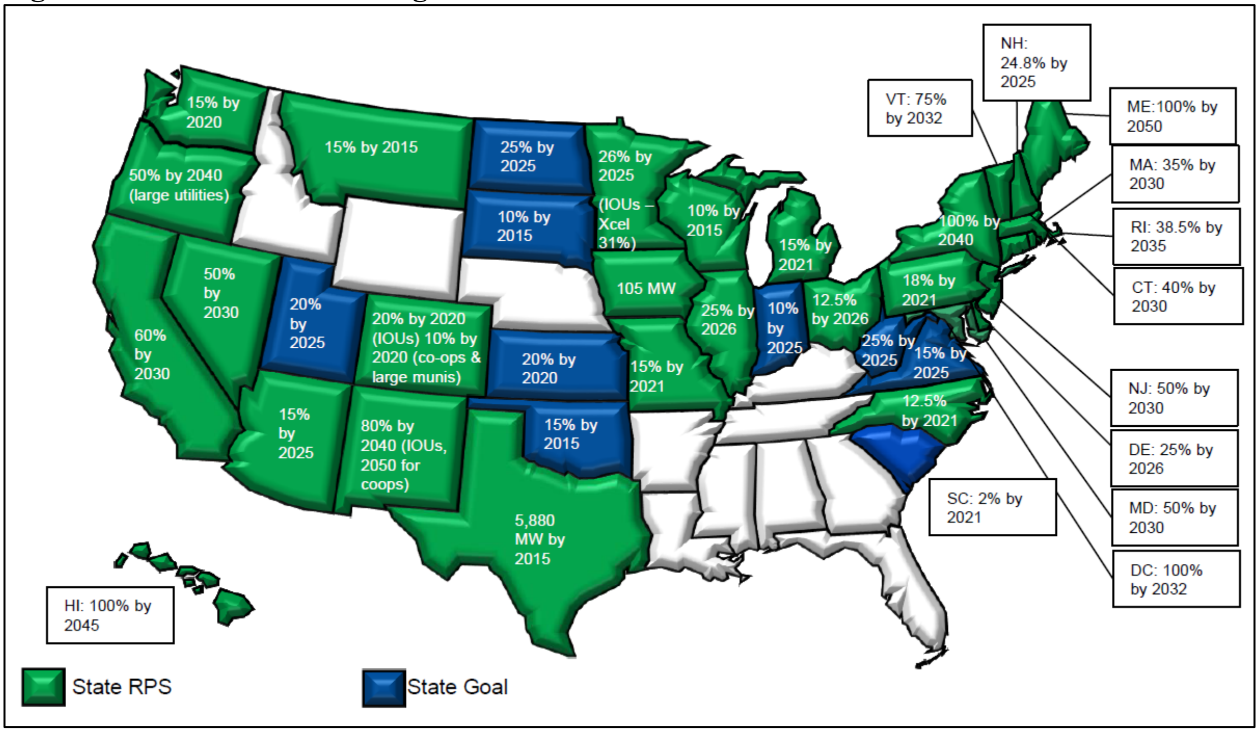
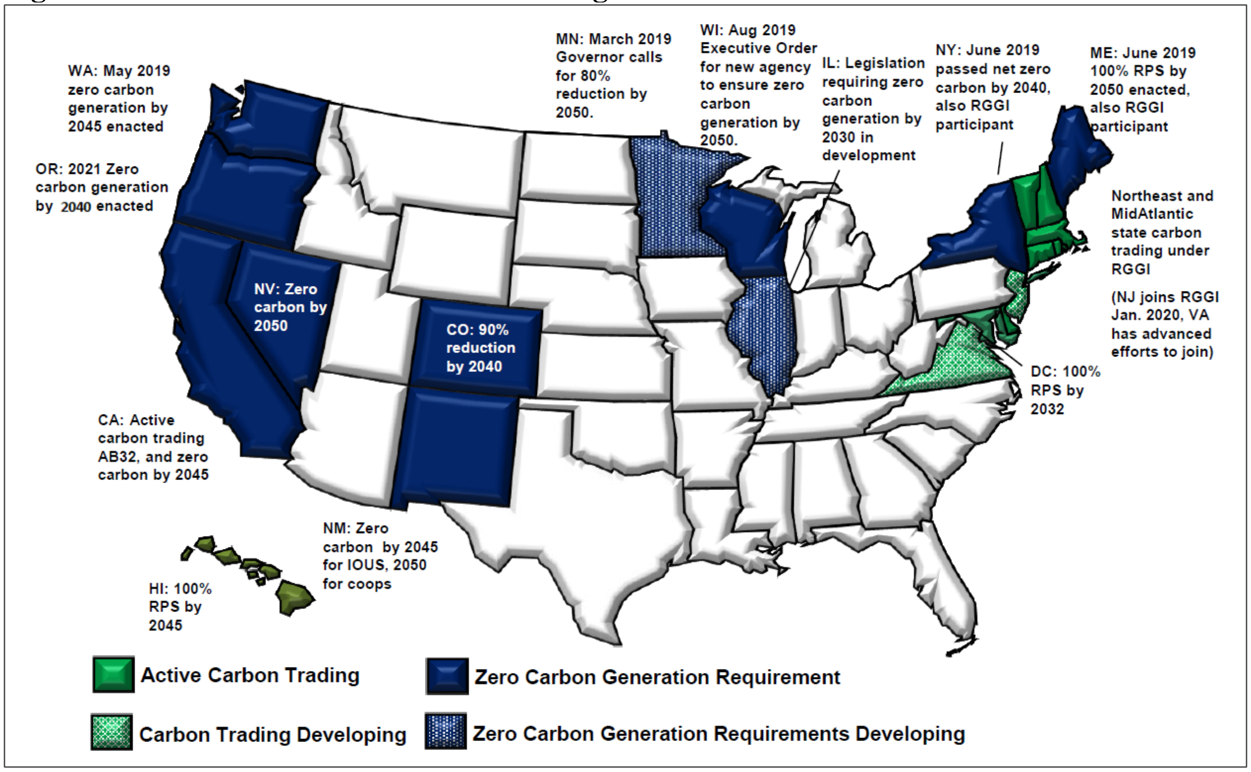
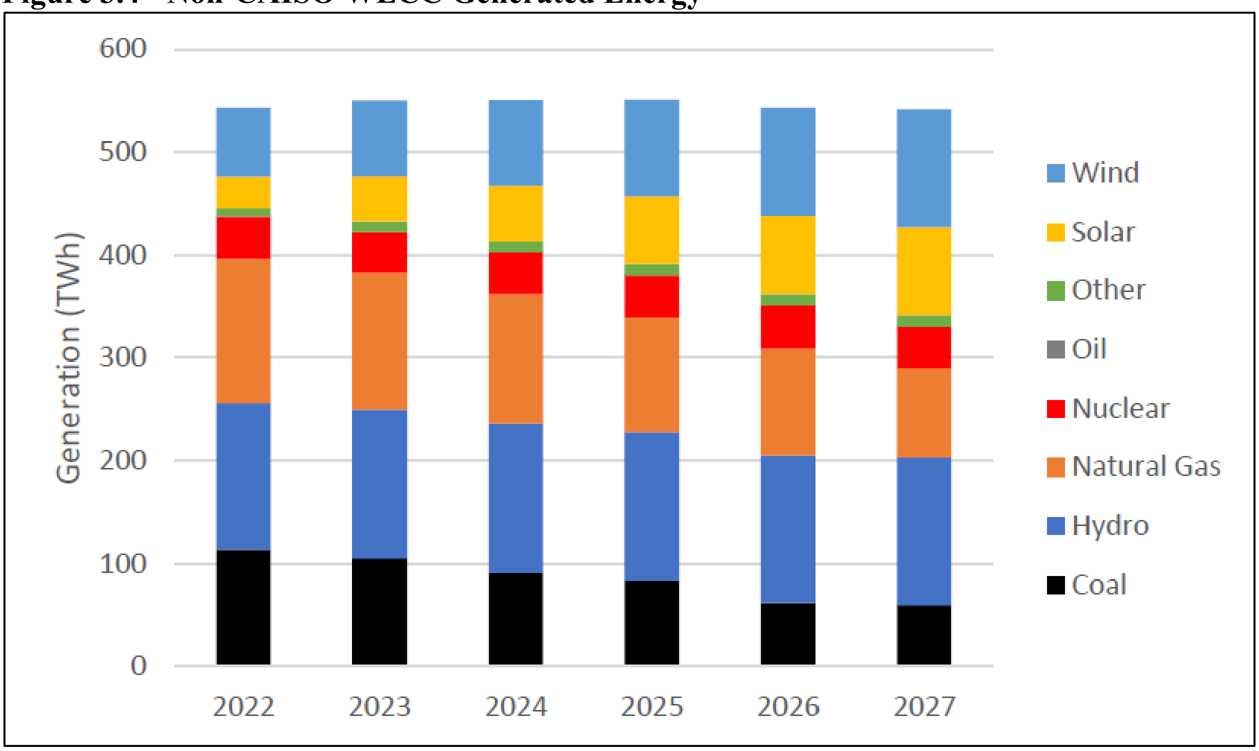


Figure 3.3 - States with CO_2 Reduction Targets



Source: Siemens PTI

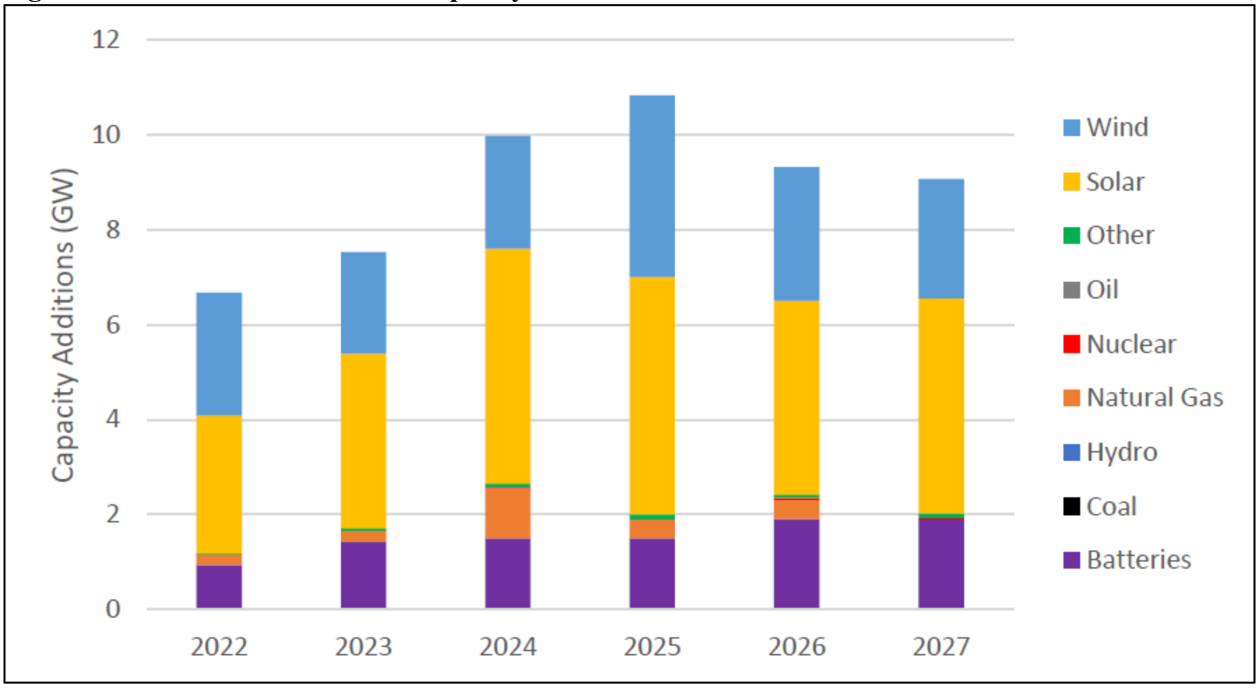
Figure 3.4 - Non-CAISO WECC Generated Energy



Source: IHS Markit, SNL, Siemens PTI

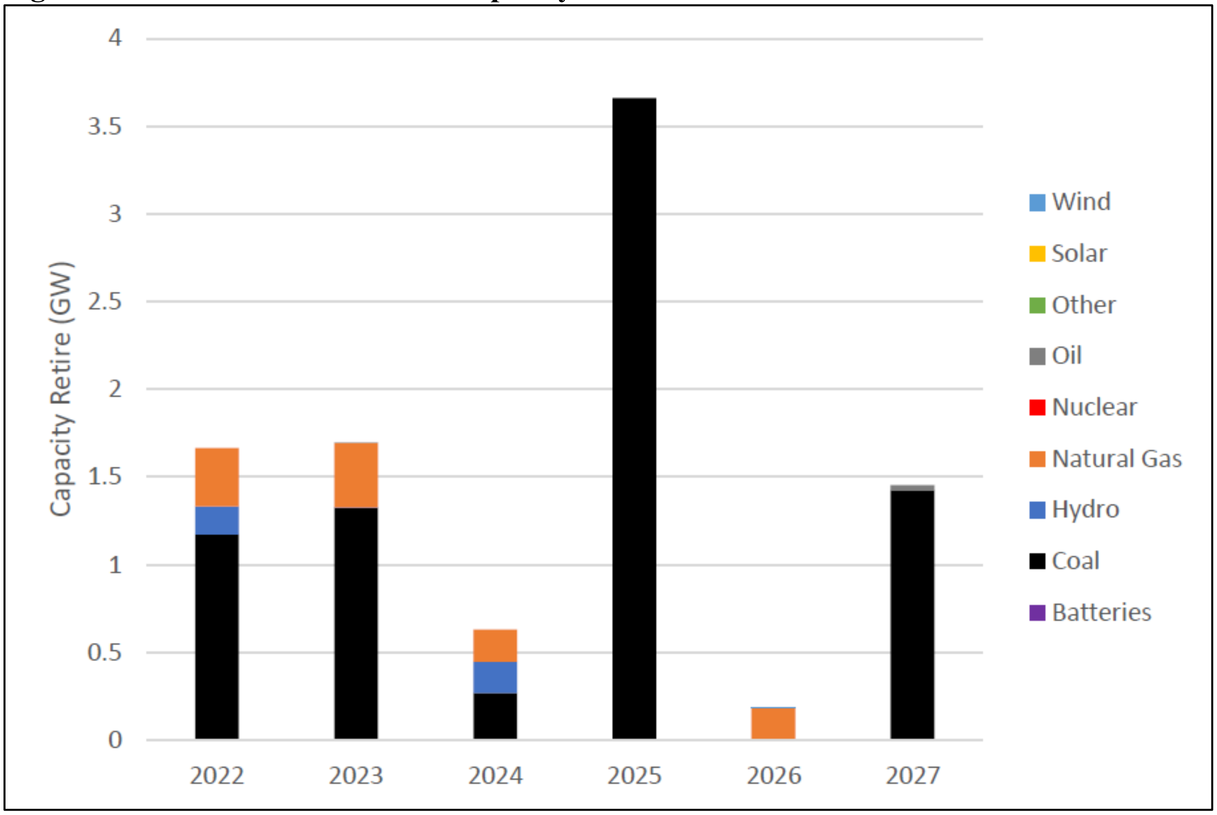
2022 saw the addition of almost 2.5 GW of wind resources and 2.9 GW of Solar. Into 2023 Siemens expects approximately 3.6 GW of wind 2.1 GW of solar to come online as according to interconnection queues. Just under 1 GW of storage capacity came online in 2022 and some 1.4 GWs of storage are expected to come online in 2023. Only about 200 MWs of fossil gas came online in 2022 with similar quantities expected to come online in 2023.

Figure 3.5 - Non-CAISO WECC Capacity Addition



Source: IHS Markit, SNL, Siemens PTI

Figure 3.6 - Non-CAISO WECC Capacity Retirement



Source: IHS Markit, SNL, Siemens PTI

Emissions and Environment

The spike in natural gas prices in 2022 caused utilities across the US to redispatch their generation resources to meet summer demand. The deployment of more coal resources than planned increased demand for NOx seasonal emissions abatements beyond utilities' initial budgets, causing NOx Seasonal emissions allotment prices to spike. In the short term, NOx Group 3 seasonal emissions policy expansion and high natural gas prices will sustain high NOx seasonal prices through 2023.

Non-CAISO WECC Demand Forecast

On average, non-CAISO WECC regional demand grew 1.1% in 2022 to 469,000 MWh in 2022 and demand is expected to continue growing around 474,000 MWh in 2023. Generally, non-CAISO WECC utilities have adjusted their five-year load expectations up for two reasons. First, broad sector emissions reductions targets are electrifying residential, transportation, and industrial processes. Second, the population growth in the Pacific Northwest and Arizona as people move for job opportunities and lower costs of living.

Forward Influence of the IRA

In August of 2022 the US Congress Passed the Inflation Reduction Act ("IRA"). The notable near-term impacts of the IRA are to allow all non-carbon emitting resources and energy storage resources to select either production tax credits and investment tax credits. Production tax credits are expected to provide greater benefits for wind, solar, and many other generation technologies and may contribute to suppressed market prices during periods of renewable resource oversupply as generators may be willing to accept negative attempt to avoid losing production tax credits.

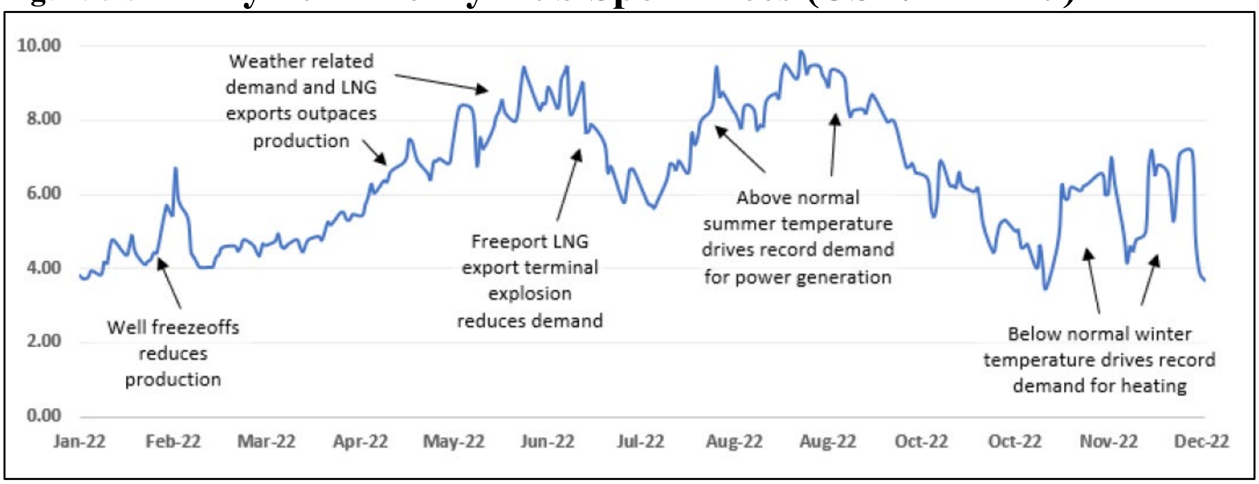
Natural Gas Prices

2022 Summary

In the first quarter of 2022, demand for natural gas surpassed production in the US due to well freeze-offs in January and February. High withdrawals of natural gas from storage during this time caused prices to increase. Continued demand for U.S. liquified natural gas (LNG) exports into Europe due to Russia's war on Ukraine, as well as increasing weather-driven demand, caused upward price pressure.

In the second quarter, starting in May, weather-related demand for natural gas for electric generation as well as uncertainty around storage injections led to an increase in natural gas prices. The Henry Hub spot prices, as you can see in Figure 3.7, rose to over $9/MMBtu. However, in late June, the second largest LNG export terminal in the US, accounting for 17% of total LNG export capacity, suffered a tragic explosion which took it offline. As such prices fell to below $6/MMBtu. For the first half of 2022, the U.S. was the largest exporter of LNG in the world, and over two-thirds of the cargoes headed to Europe.

Figure 3.7 - Daily 2022 Henry Hub Spot Prices (USD/MMBtu)



Source: S&P Global, Siemens PTI

The price of natural gas quickly rebounded in July and August, as a result of a heat wave in many parts of The U.S., which resulted in record high demand for power generation. The Western States of the U.S. were particularly affected by this not only due to higher demand for power but also from reduced supply of hydro resources due to continuing drought.

Despite these challenges, US Lower 48 supply surpassed pre-pandemic levels in the first half of 2022, led by gas production growth as higher prices spurred increased rig activity. Rig activity was more pronounced in low-cost basins such as Permian (Texas/New Mexico) and Haynesville (Louisiana) as they have better infrastructure to access demand areas.

Production growth slowed over the second half of 2022 as inflation, labor, and materials shortages, and service sector constraints continued to impact producers, keeping overall domestic production hovering around 100 Bcf/d.

Natural gas delivery in the US is complex due to the number of supply sources and pipelines that transport gas to various hubs around the country. As such prices at Henry Hub do impact prices in the West as the same source that supplies the gulf coast region can also supply the Western states.

However, there may be regional differences in price due to pipeline constraints. For instance, in December 2022 and January 2023, while most of the country had above-normal temperatures, California experienced wet and below-normal cold temperatures that significantly increased demand for natural gas. This higher demand, the constraint on pipelines, and reduce storage levels contributed to significantly higher prices that the west is currently experiencing.

2023 Forward View

The forecast of the natural gas spot price for Henry Hub is slightly higher than $4/MMBtu on average in 2023 based on forward markets. We expect the first quarter will average closer to $5/MMBtu due to winter demand, an increase in LNG exports driven by the restart of the Freeport LNG terminal, and ~100 Bcf/d of production in the U.S.

In the second quarter of 2023, we expect prices to be lower than 1Q due to decreasing demand for heating, and relatively flat demand for power generation as increasing renewable generation replaces generation from coal plants. However, we recognized that natural gas prices can be volatile at times particularly if there are weather-related events such as those experienced in 2022 or pipeline constraints that could result in higher gas prices.

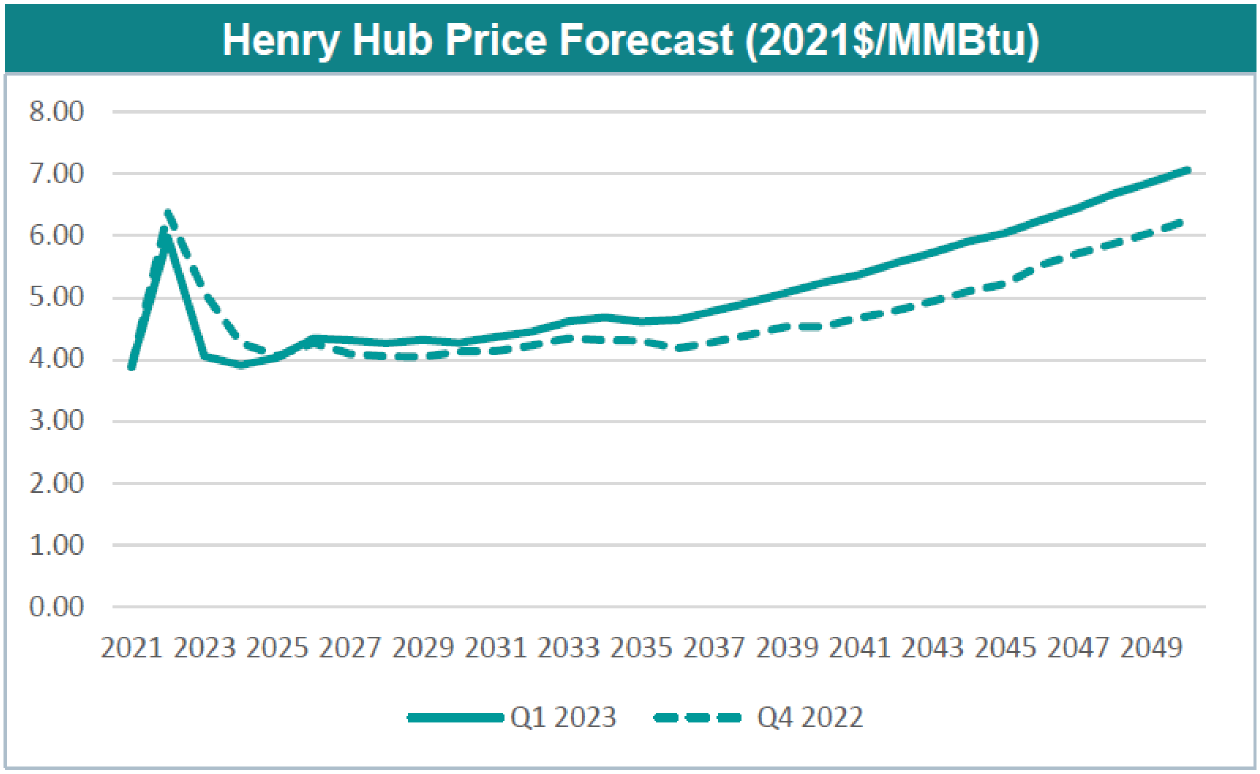
2024-2030 Forward View

Our fundamental forecast for natural gas spot prices for Henry Hub is mid $4/MMBtu in real terms. Demand for NG is expected to be 115 Bcf/d in 2030, which represents a ~12% increase from 2022 levels. While there are minor changes to residential, commercial, and industrial demand, most of the increase is expected to come from LNG and pipeline exports to Mexico.

Several LNG export terminals have reached a final investment decision, which will result doubling of capacity by 2027. Export to Mexico is also expected to increase fuel power generation and industrial demand.

To meet increasing demand, we expect supply to increase dramatically from low-cost producing basins such as Permian, Eagle Ford, and Haynesville. All of these supply basins have proximity to demand markets as well as pipeline expansion projects to ensure adequate access.

Figure 3.8 – Henry Hub Futures



Conclusion

The trajectory of gas price futures is anticipated to stabilize with global conditions, as seen in the Henry Hub forecast in Figure 3.8. The challenge in gaging the uncertainty in natural gas markets will be one of timing, wherein managing long-term boom and bust cycles is not as crucial as managing shorter-term market perturbations.

PacifiCorp's Multi-State Process

PacifiCorp is a multi-state utility that provides retail electric service to nearly 2 million customers across six states. The costs of providing this retail electric service to customers is recovered through retail rates established in regulatory proceedings in each state. To ensure states receive the appropriate allocation of costs and benefits from PacifiCorp's integrated system, the collaborative multi-state process (MSP) has been used to develop an allocation methodology. This collaborative process has led to the development and adoption of PacifiCorp's current inter-jurisdictional cost-allocation method.

The underlying principle of each of the historical inter-jurisdictional cost-allocation methods has been the use of PacifiCorp's system as a single whole. Except for distribution, all states are served from a common portfolio of generation and transmission assets, which enables the company to leverage economies of scale and take advantage of load diversity to plan and operate in a way that results in cost savings for all customers. Recently, state energy policies across the states served by the company have challenged this principle. For example, requirements to remove coal-fired generation from rates in certain states will necessarily result in some states being allocated the costs and benefits of coal-fired generation while other states are not. Similarly, diverging state polices related to implementation of the Public Utilities Regulatory Policy Act of 1978, retail choice, private generation, and incorporation of societal externalities in resource planning challenge the long-standing practice of planning for a single, integrated system.

In December 2019, PacifiCorp filed the most recent inter-jurisdictional cost-allocation methodology, known as the 2020 PacifiCorp Inter-jurisdictional Allocation Protocol (2020 Protocol). Under the 2020 Protocol, five of PacifiCorp's six retail states would continue sharing all system resources, while Washington, which had previously only recognized resources in PacifiCorp's west Balancing Authority Area, would share in all system transmission and non-emitting resources. Signatories to the 2020 Protocol have been discussing the development of a future allocation methodology that would address all states' energy policy, while maintaining the benefits of PacifiCorp's system. The guiding principles underlying the 2020 Protocol are as follows:

1. Provide a long-term, durable solution;
2. Follow cost-causation principles;
3. Minimize rate impacts at implementation;
4. Allow for state autonomy for new resource portfolio selection;
5. Maintain and optimize system-wide benefits and joint dispatch to the extent possible;
6. Enable compliance with state policies;
7. Ensure credit-supportive financial outcome; and
8. Provide the company with a reasonable opportunity to recover its costs.

List of Implemented Issues

1. **States' Decisions to Exit Coal-Fueled Interim Period Resources:** including methodology regarding allocation of costs at closure, treatment of exit orders, exit dates, and common closures, as well as the process to establish exit dates for Hayden Units 1 and 2.

2. **Reassignment of Coal-Fueled Interim Period Resources:** Includes the process, methodology, and effects of commission decisions on the potential reassignment of coal-fueled resources from a state which has issued an exit order to states that do not have exit orders.

3. **Decommissioning Costs:** specifies the timing of a contractor-assisted engineering study of decommissioning costs and appropriate decommissioning cost reserve requirements for Jim Bridger, Dave Johnston, Hunter, Huntington, Naughton, Wyodak, Hayden, and Colstrip. This item also specifies the allocation of decommissioning costs.

4. **Qualifying Facilities:** outlines a superseding framework, in which existing qualifying facilities will remain system assigned and allocated – subject to any future limited realignment – until the end of 2029, after which time they will be assigned and allocated to the state that has jurisdiction over qualifying facility pricing. During the interim period, qualifying facilities will continue to be allocated, while after the interim period,

qualifying facilities will be directly assigned to the state that has jurisdiction over qualifying facility pricing.

List of Resolved Issues

- **Generation Costs:** including the share of resources assigned to serve load in each state. Interim resources will continue to have a fixed allocation, and new resources that begin operation before the end of the interim period will use the same methodology. New resources that begin operation after the interim period will be subject to future determination as part of the framework issues.

- **Transmission Costs:** will continue to be allocated on the System Transmission factor, except as addressed as part of the "new resource assignment" framework issue.

- **Distribution Costs:** will be directly allocated to states where distribution facilities are located.

- **System Overhead Costs:** Will continue to be allocated based on the System Overhead factor but will also be subject to allocation based partially on the System Capacity, System Energy, and System Gross Plant Distribution factors.

- **Administrative and General:** will be directly allocated to states, if possible.

- **Other Allocation Issues:** modifies the allocation of certain existing miscellaneous issues.

- **Demand-Side Management Programs:** will be allocated to the state in which the investment is made, and benefits will flow back to each state through net power costs or through reduced or delayed future capacity need.

- **State-Specific Initiatives:** Will be allocated and assigned to the state adopting the initiative.

Update on 2020 Protocol and Status of Framework Issues

Following the filing of PacifiCorp's 2020 Protocol, Oregon, Idaho, Wyoming, Utah, and Washington have issued approval. California is still reviewing the 2020 Protocol as part of PacifiCorp's current general rate case.

Framework Issues Workgroup meetings continue to work through the framework issues. The workgroup has discussed both the framework issues as agreed upon in the 2020 Protocol and explored other alternatives to address concerns raised by stakeholders during discussions. Key considerations are as follows:

1. **Resource Planning and New Resource Assignment –** The continued operation, planning, and dispatch of the Company's system as an integrated six-state system will likely be beneficial to PacifiCorp customers. However, as state energy policy continues to evolve, requiring the exclusion of certain generating resources, it appears infeasible to continue serving customers with a common generation portfolio and dynamically

allocated system costs. As such, PacifiCorp will work to meet its legal requirements as a public utility in each state in a risk-adjusted, least-cost manner, while striving to mitigate cost impacts in other states. The Framework Issues Workgroup is working to develop an allocation method that allows for 1) the optimization of resource portfolios on a system basis, to the extent practicable, while meeting individual state requirements and maintaining reliability; and 2) assignment of benefits and allocation of costs of specific new resources added to meet an individual state's needs. As of March 2023, these discussions are ongoing as part of the MSP framework process.

2. **Net Power Costs and Nodal Pricing Model** – The Nodal Pricing Model is a method to track the costs and benefits of resource portfolios which may differ for each state, and to maintain the benefits of system dispatch as much as practicable. After the interim period when states may no longer participate in a common resource portfolio, the Nodal Pricing Model may be used to track cost causation and receipt of benefits by each state for ratemaking purposes. PacifiCorp worked with a third-party vendor to implement the Nodal Pricing Model, and it is currently being used for day-ahead scheduling. Use of the Nodal Pricing Model for net power costs and other applicable ratemaking proceedings may be proposed after the interim period.

3. **Special Contracts** – PacifiCorp will work directly with special contract customers to develop one or more proposals for consideration of parties. PacifiCorp continues to review options, with the intention of incorporating a proposal into the post-interim period method.

4. **Limited Realignment** – During the interim period, parties have agreed to investigate the potential for limited realignment of interim period resources, primarily related to the transition of certain state energy policy away from coal-fueled resources. These discussions are ongoing as part of the MSP process.

5. **Post-Interim Period Capital Additions for Coal-Fueled Interim Period Resources** – For coal-fueled resources for which there are differing state exit dates or when exit dates differ from the depreciable life, this issue provides a process for determining the cost allocation for capital investments made subsequent to the interim period and prior to the state exit dates. PacifiCorp has provided a straw proposal as part of the 2020 Protocol filing, and discussions are ongoing.

Analysis of "Outstanding Material Disagreements"

In compliance with Wyoming Public Service Commission Order in Docket No. 90000-144-XI-19 (Record No. 15280), PacifiCorp includes this analysis of any material disagreements regarding cost allocation at the time of the preparation and filing of the 2023 IRP.

PacifiCorp has not identified any outstanding material disagreements, and notes that the framework issue discussions are proceeding as indicated in the executed agreement as part of the 2020 Protocol. If these discussions evolve into disagreements – or if there is no agreement by the end of the interim period on December 31, 2023 – PacifiCorp may quantify the risks and potential impacts to retail rates of such a disagreement as part of a future IRP or other regulatory filing.

Environmental Regulation

The convening of the 118th U.S. Congress in January 2023 provides a backdrop of potential changes to federal energy policy within PacifiCorp's 2023 IRP cycle. Although the exact nature of these potential changes is not known at the time of filing, the company notes that changes to energy policy may impact the portfolio selection process in the 2023 IRP and in future IRPs. PacifiCorp actively monitors federal legislative requirements and participates in rulemaking processes by filing comments on various proposals, participating in scheduled hearings, and providing assessments of proposals.

Among potential federal legislative priorities under consideration, PacifiCorp notes that there have been some major recent developments.

There has been increasing focus in Congress on siting and permitting reform, focused on shortening timelines and facilitating the ability of electric companies to more efficiently build energy infrastructure. The House of Representatives recently passed HR 1, the Lower Energy Costs Act, to reform siting and permitting processes, among other perceived energy focused issues. Over the 118th Congress, the Republican controlled House of Representatives and the Democrat controlled Senate will continue to hold discussions over the prospect of siting and permitting reform.

While the Inflation Reduction Act is detailed in Federal Policy Updates, below, implementation questions remain to be answered. Attention now turns to the U.S. Treasury Department's implementation of the IRA's clean energy tax credit provisions, which will address the allocation of bonus credits, the eligibility of certain credits to certain technologies, and other key issues.

Federal Policy Update

National Electric Vehicle Infrastructure Formula Program

$5 Billion FY 2022-2026

The U.S. Department of Transportation's (DOT) Federal Highway Administration (FHWA) NEVI Formula Program will provide funding to states to strategically deploy electric vehicle (EV) charging stations and to establish an interconnected network to facilitate data collection, access, and reliability. Funding is available for up to 80% of eligible project costs, including:

- The acquisition, installation, and network connection of EV charging stations to facilitate data collection, access, and reliability;
- Proper operation and maintenance of EV charging stations; and,
- Long-term EV charging station data sharing.

Section 11401 Grants for Charging and Fueling Infrastructure

- $2.5 billion for FY 2022 – 2026.

Competitive grant program to strategically deploy publicly accessible electric vehicle charging infrastructure and other alternative fueling infrastructure along designated alternative fuel corridors. At least 50 percent of this funding must be used for a community grant program where priority is given to projects that expand access to EV charging and alternative fueling infrastructure within rural areas, low- and moderate-income neighborhoods, and communities with a low ratio of private parking spaces

New Credits and Considerations for Non-emitting Resources – Inflation Reduction Act

The Inflation Reduction Act of 2022 (IRA) is a comprehensive set of clean energy legislation, substantive details of which are still being fleshed out in the form or regulations and other guidance. The IRA contains newly structured technology-specific and technology-neutral tax credits for electric generating facilities and other clean energy incentives such as credits for Energy Storage Technology, Carbon Capture Use and Sequestration (CCUS), and hydrogen production. Furthermore, the IRA contains incentives that may affect demand such as tax credits for electric vehicles.

Features of the IRA include:

- In August 2022 President Biden signed the Inflation Reduction Act into law. The bill directs $437b in spending towards climate and healthcare investments with over $300b dedicated to deficit reduction.
- The bill extends existing and creates new energy investment and production tax credits and institutes a new technology-neutral zero emission generation tax credit in 2025, supplanting the extended generation-specific credits. Eligibility expires upon meeting economy-wide emissions reduction targets. The bill also establishes a new 15% corporate minimum book tax and a new 1% excise tax on corporate stock buybacks.
- Key Energy Provisions:
    - Extends wind, geothermal, and solar investment and production tax credits at full value through December 31, 2024. Solar projects are newly eligible to apply the production tax credit to energy generated. Additional 10% bonus credits each are available for both locating projects in communities with retired coal operations and meeting certain domestic content requirements; achieving full credit value is also conditioned on meeting wage and apprenticeship requirements.
    - Establishes new tax credits for clean hydrogen, microgrids, electric vehicle purchases, existing nuclear generation, and the domestic manufacture of solar, wind, and battery components. Value and eligibility for existing carbon capture and sequestration credits are also enhanced and expanded
    - Institutes a new technology-neutral, zero emission generation tax credit in 2025, supplanting the extended technology-specific credits. The technology-neutral credits phase down upon meeting economy-wide emissions reduction targets

In the 2023 IRP, resources in Utah South and all of Wyoming are assumed to receive the 10% Energy Community bonus, resulting in a 110% PTC (wind, solar, other energy resources) or 40% ITC (energy storage and peaking resources)

New Credits and Considerations for Customer Resources–Inflation Reduction Act

Beginning January 1, 2023, the Clean Vehicle Credit (CVC) provisions remove manufacturer sales caps, expand the scope of eligible vehicles to include both EVs and FCEVs, and require a traction battery that has at least seven kilowatt-hours (kWh). An available tax credit under the CVC may be limited by the vehicle's MSRP and the buyer's modified adjusted gross income
Once the Treasury Department issues the critical mineral and battery component guidance, vehicles that meet the critical mineral requirements are eligible for $3,750 tax credit, and vehicles that meet the battery component requirements are eligible for a $3,750 tax credit. Vehicles meeting

both the critical mineral and the battery component requirements are eligible for a total tax credit of $7,500.

The IRA also extends Federal Investment Tax Credit (ITC) for small scale solar systems through 2034 and expands credit to include standalone energy storage systems as well. Since the passing of the IRA, the ITC has been extended past its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC would be set at 26 percent. In addition to the new federal ITC schedule for generating facilities, the updated ITC includes credits for standalone energy storage with a capacity of at least 3 kWh for residential customers and 5 kWh for non-residential customers.

The IRA funds multiple programs and tax incentives to improve the energy efficiency for residential and non-residential buildings and equipment. For non-residential buildings, the IRA provides tax deductions of $0.50–5.00 per square foot (/sf) of floor area to owners of new and improved energy-saving commercial buildings depending on the percentage of energy savings and whether the contractor pays prevailing wages. Even larger broad greenhouse gas emission reduction programs under the IRA could be used to reduce emissions from commercial buildings. The IRA also provides more than $25 billion for programs and tax incentives to improve the energy efficiency of existing and new homes. In addition to program funding, the IRA enhances the 25C Energy Efficient Home Improvement Credit. This long-standing federal tax credit applies to home energy improvements such as insulation, windows, heat pumps, and furnaces. Starting in 2023, IRA increases the credit to 30% of cost, with an annual cap of $1,200 along with smaller limits for most items, but it also allows up to $2,000 for a heat pump (in 2022 the credit is under the old rules, with lower amounts and a lifetime cap of $500).

New Source Performance Standards for Carbon Emissions–Clean Air Act § 111(b)

New Source Performance Standards (NSPS) are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. On August 3, 2015, the United States Environmental Protection Agency (EPA) issued a final rule limiting CO_2 emissions from coal-fueled and natural-gas-fueled power plants. Under that rule, new natural-gas-fueled power plants could emit no more than 1,000 pounds of CO_2 per megawatt-hour (MWh). New coal-fueled power plants could emit no more than 1,400 pounds of CO_2/MWh. The final rule largely exempted simple cycle combustion turbines from meeting the standards. In January 2021, the EPA issued a revised NSPS for CO_2 emissions. However, in April 2021, at the request of the EPA as directed by the Biden Administration, the D.C. Circuit vacated and remanded the January 2021 final rule. EPA's latest regulatory agenda projects the agency will propose new NSPS rules for CO_2 in April 2023 and plans to finalize the rule by June 2024.

Carbon Emission Guidelines for Existing Sources – Clean Air Act § 111(d)

On August 3, 2015, EPA issued a final rule, referred to as the Clean Power Plan (CPP), regulating CO_2 emissions from existing power plants. On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. On October 10, 2017, EPA proposed to repeal the CPP and on August 21, 2018, proposed the Affordable Clean Energy (ACE) rule to replace the

CPP. The ACE rule sets forth a list of "candidate technologies" that states can use to reduce greenhouse gas emissions at coal-fueled power plants. The ACE rule was finalized June 19, 2019, replacing the CPP. On January 19, 2021, the D.C. Circuit vacated the ACE rule and directed the EPA to proceed with new rulemaking for the control of carbon emissions from electric utility coal-fired boilers. On June 30, 2022, the U.S. Supreme Court held in *West Virginia v. EPA* that the "economic and political significance" of the CPP's generation shifting approach went beyond the authority granted to the agency by congress to regulate existing emission sources under section 111(d) of the Clean Air Act.

Credit for Carbon Oxide Sequestration – Internal Revenue Service § 45Q

In 2008, the Internal Revenue Service issued a tax credit for carbon oxide sequestration under section 45Q to incentivize carbon capture and sequestration (CCS) investments. The tax credit is computed per metric ton (tonne) of qualified carbon oxide captured and sequestered.[9] Carbon oxide can either be permanently disposed of in secure geological storage or the carbon oxide can be utilized – typically as a tertiary injectant in enhanced oil recovery (EOR).

The Bipartisan Budget Act of 2018 reformed 45Q for carbon capture equipment that is placed in service on or after February 9, 2018, increasing the credit amount from $10/tonne to $35/tonne for utilization and from $20/tonne to $50/tonne for storage.[10] This Act also removed the limit on the amount of tax credits that could be awarded for CCS, and, instead, requires a minimum amount of carbon oxide to be capture annually (500,000 tonnes per year for an electric generating facility) and is available for 12 years from the date the carbon capture equipment is originally placed into service. The Consolidated Appropriations Act of 2021 extended the date construction must begin to receive the tax credits by two years, from January 1, 2024 to January 1, 2026.

The Inflation Reduction Act made considerable changes to the 45Q tax credit in 2022. The tax credit amount increased to $60/tonne (use) and $85/tonne (storage), the construction window was extended to January 1, 2033, the minimum capture thresholds were lowered (18,750 tonnes per year for electric generating facilities) and the Act now requires 75% of a generating units CO_2 production to be captured, among other requirements.

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants that have the potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the general public, and establish the maximum allowable concentration allowed for each "criteria" pollutant in outdoor air. The six pollutants are carbon monoxide, lead, ground-level ozone, nitrogen dioxide (NO_X), particulate matter (PM), and sulfur dioxide (SO_2). The standards are set at a level that protects public health with an adequate margin of safety. If an area is determined to be out of compliance with an established NAAQS standard, the state is required to develop a state implementation plan to bring that area into compliance, and that plan must be approved by EPA. The plan is developed so that once implemented, the NAAQS for the pollutant of concern will be achieved.

[9] Before February 9, 2018, the tax credit was strictly for CO_2.
[10] The tax credit reaches $35/tonne and $50/tonne in 2026.

Ozone NAAQS

In October 2015, EPA issued a final rule modifying the standards for ground-level ozone from 75 parts per billion (ppb) to 70 ppb. On November 16, 2017, the EPA designated all counties where PacifiCorp's coal facilities are located (Lincoln, Sweetwater, Converse and Campbell Counties in Wyoming; and Emery County in Utah) as "Attainment." On June 4, 2018, the EPA designated Salt Lake County and part of Utah County, where the PacifiCorp Lake Side and Gadsby gas facilities are located, as "Marginal Nonattainment." A marginal designation is the least stringent classification for a nonattainment area and does not require a formal State Implementation Plan (SIP). Utah submitted its strategy for meeting the standard to EPA in May of 2021.

These areas were required to attain the ozone standard by August 3, 2021. On October 7, 2022, EPA determined that the Southern Wasatch Front area of Utah had attained the ozone standard. However, in the same rule, EPA determined that the Northern Wasatch Front area failed to attain the standard and would be bumped up to a moderate nonattainment designation. The Gadsby gas facility is a major source located in the Northern Wasatch Front area. The moderate nonattainment designation requires the state to conduct an analysis of reasonably available control technology (RACT) for major sources of volatile organic compounds (VOCs)/NOx. It is expected that PacifiCorp will submit an updated RACT analysis for the Gadsby plant in 2023.

In addition to meeting the ozone NAAQS for areas within a state, states must also conduct an analysis of cross-state air pollution and whether emissions from the state have a significant impact on neighboring states attaining or maintaining the ozone NAAQS. On April 6, 2022, EPA proposed its "Good Neighbor Rule" for the 2015 ozone NAAQS, which contains a federal implementation plan (FIP) with proposed revisions to the existing Cross-State Air Pollution Rule (CSAPR) framework. The CSAPR FIP is intended to address cross-state ozone transport for the 2015 ozone NAAQS through uniform federal requirements and jurisdiction. EPA's proposed FIP is focused on reducing NOx, which are precursors to ozone formation. The proposed rule covers 26 states, including four western states included in the cross-state program for the first time – Wyoming, Utah, Nevada and California. Utah and Wyoming would be included in the program based on alleged significant impacts on ozone levels in Colorado.

The proposed CSAPR FIP includes NOx trading budgets and requirements for electric generating units. Beginning in 2023, emissions budgets will be set at the level of reductions achievable through immediately available measures such as consistently operating existing emissions controls, generation shifting or installing state-of-the-art low NOx burners (LNB) on select units. Starting in 2026, emissions budgets will be set at levels only achievable by the installation of selective catalytic reduction (SCR) controls at certain electric generating units.

On May 24, 2022, the EPA also proposed to disapprove the cross-state ozone transport state implementation plans (CSAPR SIPs) of numerous states to mitigate interstate ozone transport, including plans by Utah and Wyoming. Disapproval of the SIPs is a necessary prerequisite before EPA can finalize the expanded CSAPR FIP to federally regulate the western states for the first time. The proposed SIP disapprovals were made as part of a settlement agreement with environmental groups. For both Utah and Wyoming, the agency determined that, among other failings, the states should have used a one percent threshold instead of the one ppb threshold previously suggested by EPA that the states used to determine downwind impacts. Final disapproval of the SIPs will subject the states to the proposed CSAPR FIP for the 2015 ozone standard.

Berkshire Hathaway Energy (BHE) submitted comments on behalf of affected companies, including PacifiCorp, on EPA's proposed CSAPR FIP on June 21, 2022. The comments drew attention to several concerns with the proposed rule. First, the companies believe that western states should be removed from the proposed rule because it is based on a pre-existing framework that was not designed for western states. EPA incorporated the four new western states into the proposed rule based on flawed modeling and questionable administrative procedures. In addition, the proposed rule is likely to force early coal-unit retirements on a timeline that is expected to disrupt the reliable delivery of electricity and could directly result in electricity shortages throughout the West. If EPA does not remove western states from the final rule, recognizing that reliability concerns remain, the companies asked the agency to undertake meaningful outreach with the Western Electricity Coordinating Council and the North American Energy Reliability Corporation and other affected regional transmission organizations to ensure that any final interstate transport rule is appropriately modeled to address reliability impacts. If the agency will not remove the states from the final rule, the companies also identified several elements of the proposed rule and the trading program for electric generating units that need to be changed or corrected.

PacifiCorp also submitted comments on July 25, 2022, in opposition to EPA's proposed disapproval of both Utah and Wyoming's SIPs. The comments identified concerns with the proposed disapprovals. First, the disapproval of the state plans is directly related to the agency's planned imposition of the FIP that will result in major economic and reliability impacts on western states. Second, EPA issued the FIP before finalizing disapproval of the state plans, indicating flawed procedures and a predetermined outcome. Third, the agency acts contrary to its own guidance and relies on flawed modeling. PacifiCorp requested that the agency either approve both SIPs or work with Utah and Wyoming to achieve an approvable plan for each state.

On January 31, 2023, EPA delayed final action on Wyoming's CSAPR SIP until December of 2023 and indicated a supplemental SIP decision may be necessary. Wyoming will not be subject to the CSAPR FIP unless EPA disapproves the SIP. EPA finalized disapproval of Utah's CSAPR SIP along with 18 other states and issued a partial disapproval for two additional states. EPA finalized the CSAPR FIP March 15, 2023. The CSAPR FIP is expected to be published in the Federal Register 2-6 weeks from the finalization, meaning the CSAPR FIP may not go into effect until after the 2023 ozone season has started. PacifiCorp continues to engage with EPA and the states on issues of reliability and the SIP and FIP processes while also developing necessary compliance measures and evaluating reliability impacts.

Numerous states and industries have challenged certain provisions of the CSAPR SIP disapprovals and are expected to challenge the final CSAPR FIP after it is published in the Federal Register. The state of Utah and PacifiCorp have filed petitions and motions for stay of EPA's denial of the state plan with EPA and the U.S. Tenth Circuit Court of Appeals (Tenth Circuit). The state of Wyoming filed a petition for reconsideration with EPA of its deferral of a final decision on Wyoming's ozone interstate transport plan on March 14, 2023.

Particulate Matter NAAQS

In April 2017, the EPA Administrator signed a final action to reclassify the Salt Lake City and Provo $PM_{2.5}$ nonattainment area from moderate to serious. PacifiCorp's Lake Side and Gadsby facilities were identified as major sources subject to Utah's serious nonattainment area SIP for $PM_{2.5}$ and $PM_{2.5}$ precursors. On April 27, 2017, PacifiCorp submitted a Best Available Control Technology (BACT) analysis for Lake Side and Gadsby to the Utah Division of Air Quality for review. On January 2, 2019, the Utah Air Quality Board adopted source specific emission limits and operating practices in the SIP which incorporated the current emission and operating limits for the Lake Side and Gadsby facilities.

Regional Haze

EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility, by 2064, in certain national park and wilderness areas. Many of these areas are in the western United States where PacifiCorp owns and operates several coal-fired generating units (Utah, Wyoming, Colorado and Montana as well as Arizona, where a PacifiCorp-owned coal unit ceased operating in 2020). The states are required to update their regional haze rule plans approximately every ten years, with second planning period revisions due in August of 2023. Litigation over the first planning period requirements for both Utah and Wyoming are on-going.

On June 15, 2005, EPA issued final amendments to its regional haze rule to require emission controls known as BART for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. The regulated pollutants include fine PM, NOx, SO_2, certain VOCs, and ammonia. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART guidelines, as well as establishing BART emissions limits for those facilities.

On August 20, 2019, EPA issued a final guidance document on the technical aspects of developing regional haze SIPs for the second implementation period of the regional haze program. EPA issued additional guidance through a memorandum on July 8, 2021, that emphasizes the 4-factor reasonable progress analysis for the second planning period and the reduced weight of visibility as a factor in the second planning period.

Utah Regional Haze

In May 2011, the state of Utah issued a regional haze SIP requiring the installation of SO_2, NOx and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NOx and PM portions. EPA's approval of the SO_2 SIP was appealed by environmental advocacy groups to the Tenth Circuit. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the NOx and PM SIP. PacifiCorp and the state's appeals were dismissed, and the SO_2 appeal was denied by the Tenth Circuit. In June 2015, the state of Utah submitted a revised SIP to EPA for approval with an alternative BART NOx analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, crediting NOx controls previously installed on Hunter Unit 3, and concluding that no incremental controls (beyond those included in the May 2011 SIP and already installed) were required at the Hunter and Huntington units. On June 1, 2016, EPA issued a final rule to partially approve and partially disapprove Utah's regional haze SIP and propose a FIP. The FIP required the installation of SCR controls by August 4, 2021, at four of PacifiCorp's units in Utah, including Hunter Units 1 and 2 and Huntington Units 1 and 2. On September 2, 2016, the state of Utah and PacifiCorp filed petitions for administrative and judicial review of EPA's final rule, followed by a motion to stay the effective date of the final rule.

On June 30, 2017, Utah and PacifiCorp provided new information to EPA, again requesting reconsideration. EPA responded on July 14, 2017, indicating its intent to reconsider its FIP. EPA also filed a motion with the Tenth Circuit to stay EPA's FIP and hold the litigation in abeyance pending the rule's reconsideration. On September 11, 2017, the Tenth Circuit granted the petition for stay and the request for abatement. The compliance deadline of the FIP and the litigation were stayed pending EPA's reconsideration, and EPA was required to file periodic status reports with the court.

Utah and PacifiCorp worked with EPA to develop a revised Utah regional haze SIP, based on new CAMx modeling. The Utah Air Quality Board approved the revised SIP on June 24, 2019, and the SIP revision was submitted to EPA for review on July 3, 2019. On December 3, 2019, Utah submitted a supplement to EPA with a minor SIP revision relating to $PM_{2.5}$.

On January 10, 2020, the EPA published its proposed approval of the Utah SIP revision and withdrawal of the FIP requirements for the Hunter and Huntington plants to install SCR on Hunter Units 1 and 2 and Huntington Units 1 and 2. After receiving public comments and holding a public hearing in the Price area on February 12, 2020, EPA issued final approval of the Utah SIP revision and FIP withdrawal on November 27, 2020. The final rule credits existing NOx emission controls at the Hunter and Huntington plants as well as NOx and PM emission reductions provided by the closure of the Carbon plant in 2015. Based on the newly approved plan, EPA also withdrew the 2016 FIP requirements to install SCR control technology on Hunter Units 1 and 2 and Huntington Units 1 and 2. On January 11, 2021, the Tenth Circuit granted Utah, PacifiCorp and EPA's motion to dismiss the Utah regional haze petitions.

Environmental advocacy groups filed a petition for review in the Tenth Circuit on January 19, 2021, objecting to the revised Utah regional haze SIP. After holding the case in abeyance at EPA's request, the Tenth Circuit lifted the abeyance and granted PacifiCorp and Hunter co-owners and Utah's pending motions to intervene. Briefing concluded on June 16, 2022, with EPA, Utah, PacifiCorp and the Hunter co-owners supporting Utah and EPA's determinations to approve the SIP. The Tenth Circuit set the date for oral argument on March 21, 2023. PacifiCorp is coordinating oral argument with EPA and the state of Utah.

Utah Regional Haze Second Planning Period – On April 21, 2020, PacifiCorp submitted a Regional Haze Reasonable Progress Analysis for the second planning period to the Utah Department of Environmental Quality for PacifiCorp's Huntington and Hunter plants. The analysis was requested by the state as part of its second planning period SIP development process. PacifiCorp's analysis included a proposal to implement reasonable progress emission limits for NOx and SO_2 at the Hunter and Huntington units to meet second planning period requirements.

The Utah Air Quality Division proposed, and the Utah Air Quality Board approved, final adoption of a SIP for the regional haze second planning period on July 6, 2022. The SIP differs from PacifiCorp's initial submission and requires updated mass-based NOx limits as well as a SO_2 rate-based limit for the Hunter and Huntington plants. EPA notified Utah on August 22, 2022, that its SIP submittal was complete. EPA has 12 months from August 22, 2022, to approve or disapprove all or parts of the Utah second planning period SIP.

Wyoming Regional Haze
On January 10, 2014, EPA issued a final rule partially approving and partially disapproving the Wyoming regional haze SIP. The 2014 final rule required installation of the following NOx and PM controls at PacifiCorp facilities for regional haze first planning period:

- Naughton Units 1 and 2: BART is LNB/over-fired air (OFA)
- Naughton Unit 3 by December 31, 2014: SCR equipment and a baghouse
- Jim Bridger Unit 3 by December 31, 2015: SCR equipment
- Jim Bridger Unit 4 by December 31, 2016: SCR equipment
- Jim Bridger Unit 2 by December 31, 2021: SCR equipment
- Jim Bridger Unit 1 by December 31, 2022: SCR equipment
- Dave Johnston Unit 3: SCR within five years or a commitment to shut down in 2027
- Wyodak: SCR equipment within five years

Naughton – In its 2014 rule, EPA approved Wyoming's determination that BART for Units 1 and 2 was LNB/OFA. EPA also indicated support for the conversion of the Naughton Unit 3 to natural gas in lieu of retrofitting the unit with SCR and stated that it would expedite consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. Wyoming submitted its regional haze SIP amendment regarding Naughton Unit 3 to EPA on November 28, 2017. On March 7, 2017, Wyoming issued PacifiCorp a permit for Unit 3's conversion to natural gas, which allowed operation of Unit 3 on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019, as required by the permit. EPA's final rule approval of Wyoming's SIP revision for Naughton Unit 3 gas conversion was published in the Federal Register on March 21, 2019, with an effective date of April 22, 2019. Naughton Unit 3 currently operates on natural gas. Environmental groups petitioned EPA's approval of LNB/OFA as BART for Units 1 and 2 in the Tenth Circuit. Briefing is currently underway. EPA is defending its approval of LNB/OFA as BART, and PacifiCorp and Wyoming have intervened in support of EPA. A final decision from the Tenth Circuit is expected summer or fall of 2023.

Jim Bridger – In its 2014 rule, EPA approved Wyoming's SIP determination that BART for Jim Bridger Units 1 through 4 was LNB/OFA, with SCR required over staggered years under long-term strategy requirements. SCR was installed on Jim Bridger Units 3 and 4 by the dates required by the Wyoming SIP. On February 5, 2019, PacifiCorp submitted to Wyoming an application and proposed SIP revision instituting plant-wide variable average monthly-block pound per hour NOx and SO_2 emission limits, in addition to an annual combined NOx and SO_2 limit, on all four Jim Bridger boilers in lieu of the requirement to install SCR on Units 1 and 2. The proposed SIP revision demonstrated that the proposed limits were more cost effective while leading to better modeled visibility than the SCR installation on Units 1 and 2. Wyoming submitted a regional haze SIP revision to the EPA on May 14, 2020, that incorporated PacifiCorp's proposed emission limits in lieu of the requirement to install SCR systems on Jim Bridger Units 1 and 2. While EPA communicated that it would issue a proposed approval of Wyoming's Jim Bridger SIP, the proposal was not issued before the administration change in 2021.

When EPA failed to issue a determination by the statutory deadline in November 2021, the Governor of Wyoming issued a temporary emergency order on December 27, 2021, using authority granted by the Clean Air Act, suspending the existing SIP requirement for Jim Bridger Unit 2 to install SCR by December 31, 2021. The suspension was issued for four months due to the EPA's failure to act on the SIP revision submitted by Wyoming in 2020. EPA published a proposed disapproval of the Jim Bridger SIP revision in the Federal Register on January 18, 2022. However, PacifiCorp negotiated a consent decree with Wyoming and an administrative consent order with EPA and the disapproval was not finalized. Under the Wyoming consent decree and EPA administrative consent order, PacifiCorp is required to comply with a compliance plan that allows continued operation of Jim Bridger Units 1 and 2 under the emission limits established by Wyoming in 2020 until they are converted to natural gas in 2024. The consent decree committed Wyoming to processing a SIP revision requiring the conversion and imposing post-conversion emission limits.

On December 30, 2022, Wyoming submitted a state-approved revised regional haze SIP requiring natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. The SIP conversion replaces the previous requirement for SCR at the units. Wyoming also issued an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 on December 28, 2022. EPA is reviewing the submission and is expected to conduct a separate federal public comment process on the plan during the summer of 2023. On March 9, 2023, PacifiCorp submitted a notice of compliance and request for termination of the EPA order, which is currently under EPA review. The Wyoming consent decree remains in effect. The conversion process is underway at the units, and the units must be converted or cease operations in preparation for conversion by January 1, 2024.

Dave Johnston – Under regional haze, the Dave Johnston plant was required to either install SCR on Dave Johnston Unit 3 or retire the unit by the end of 2027. PacifiCorp has committed to close Unit 3 by the end of 2027.

Wyodak – PacifiCorp and the state of Wyoming petitioned EPA's FIP requiring SCR at Wyodak in the Tenth Circuit. PacifiCorp and other parties successfully requested a stay of EPA's final rule relating to EPAs FIP pending court resolution of the petition. PacifiCorp subsequently submitted a request for reconsideration to EPA and engaged in a settlement process with EPA and Wyoming. The EPA, state of Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020. EPA published the Settlement Agreement in the Federal Register requesting public comment on January 4, 2021. PacifiCorp submitted formal comments to the EPA on March 5, 2021, in support of the Wyodak Settlement Agreement. The public comment period was extended through July 6, 2021. However, EPA did not proceed with final approval of the Settlement Agreement and re-engaged with Wyoming and PacifiCorp in mediation through the Tenth Circuit regarding paths for resolution. As described above for the Naughton case, the Wyodak case recommenced when the mediation process was not successful. Briefing is currently underway. PacifiCorp and Wyoming have challenged EPA's determination that Wyodak must install SCR equipment. The SCR requirement in EPA's FIP remains stayed during the court process. A final decision from the court is expected summer or fall of 2023.

Wyoming Regional Haze Second Planning Period – On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis toWyoming which analyzed PacifiCorp's Naughton, Jim Bridger, Dave Johnston, and Wyodak plants. The four-factor analyses was used by the state in its development of the SIP for the regional haze second planning period. Wyoming required emission limits and recognized planned unit retirements during the second planning period but did not require new controls to make reasonable progress. Wyoming submitted the state's regional haze SIP for the second planning period to the EPA before the August 15, 2022, statutory deadline. EPA notified Wyoming that its submittal was complete in August of 2022. PacifiCorp supports the state plan as it meets regional haze requirements. The agency has 12 months to approve or disapprove all or part of the state's plan.

Arizona Regional Haze

The state of Arizona issued a regional haze SIP requiring, among other things, the installation of SO_2, NOx and PM controls on Cholla Unit 4, which is owned by PacifiCorp and operated by Arizona Public Service. EPA approved in part and disapproved in part the Arizona SIP and issued a FIP requiring the installation of SCR equipment on Cholla Unit 4. PacifiCorp filed an appeal regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as related to their interests. For the Cholla FIP requirements, the court stayed the appeals while parties attempted to agree on an alternative compliance approach.

In July 2016, the EPA issued a proposed rule to approve an alternative Arizona SIP, which included the option to convert Cholla 4 to a natural gas-fired unit or retire the unit by 2025. EPA approved the revised SIP on March 27, 2017. The final action allowed Cholla Unit 4 to utilize coal until April 30, 2025, with an option to convert to gas by July 31, 2025. Cholla Unit 4 was retired in December 2020.

Colorado Regional Haze

The Colorado regional haze SIP required SCR controls at Craig Unit 2 and Hayden Units 1 and 2. In addition, the SIP required the installation of selective non-catalytic reduction (SNCR) technology at Craig Unit 1 by 2018. Environmental groups appealed EPA's action, and PacifiCorp intervened in support of EPA. In July 2014, parties to the litigation other than PacifiCorp entered into a settlement agreement that requires installation of SCR equipment at Craig Unit 1 in 2021.

In February 2015, Colorado submitted a revised SIP to EPA for approval. As part of a further agreement between the owners of Craig Unit 1, state and federal agencies, and parties to previous settlements, the owners of Craig agreed to retire Unit 1 by December 31, 2025, or, to convert the unit to natural gas by August 31, 2023. The Colorado Air Quality Board approved the agreement on December 15, 2016. Colorado submitted the corresponding SIP amendment to EPA Region 8 on May 17, 2017. EPA approved the SIP on July 5, 2018.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule required that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities. On April 25, 2016, the EPA published a Supplemental Finding that determined that it is appropriate and necessary to regulate under the MATS rule which addressed a Supreme Court decision requiring consideration of costs.

On February 7, 2019, the EPA published a reconsideration of the Supplemental Finding in which it proposed to find that it is not appropriate and necessary to regulate hazardous air pollutants, reversing the Agency's prior determination. In May 2020, the EPA published its decision to repeal the appropriate and necessary findings in the MATS rule regarding regulation of electric utility steam generating units, and to retain the rule's current emission standards. The rule took effect in July 2020. Several petitions for review were filed in the D.C. Circuit by parties challenging and supporting the EPA's decision to rescind the appropriate and necessary finding. The court granted EPA's motion to hold the cases in abeyance while the agency reviewed the 2020 repeal. On February 9, 2022, EPA published a rule proposing to rescind the 2020 revocation of the appropriate and necessary finding and to reinstate the finding. EPA also solicited information on the performance and cost of new or improved technologies to control hazardous air pollutants (HAP) emissions, improved methods of operation, and risk-related information for the required review of the MATS rule and the risk and technology review. EPA published its decision on March 6, 2023, to revoke the May 2020 finding, concluding that it is appropriate and necessary to regulate coal and oil-fired electric generation units under section 112 of the Clean Air Act. PacifiCorp plants are in compliance with the MATS standards, so the reinstatement of the finding has no immediate practical effect. However, PacifiCorp is monitoring potential legal proceedings that may be restarted based on this decision.

Coal Combustion Residuals

In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts under the Resource Conservation and Recovery Act (RCRA). The final rule became effective October 19, 2015. The final rule regulates coal combustion byproducts as non-hazardous waste under RCRA Subtitle D and establishes minimum nationwide standards for the disposal of coal combustion residuals (CCR). Under the final rule, surface impoundments and landfills utilized for coal combustion byproducts may need to be closed unless they can meet the more stringent regulatory requirements. The final rule requires regulated entities to post annual groundwater monitoring and corrective action reports. The first of these reports was posted to PacifiCorp's CCR compliance data and information websites in March 2018. Based on the results in those reports, additional action was required under the rule. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCR. Before the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCR, and hence are not subject to the final rule.

Multiple parties filed challenges over various aspects of the final rule in 2015, resulting in settlement of some of the issues and subsequent regulatory action by the EPA, including subjecting inactive surface impoundments to regulation. In response to legal challenges and court actions, EPA, in March 2018, issued a proposal to address provisions of the final CCR rule that were remanded back to the agency. The proposal included provisions that establish alternative performance standards for owners and operators of CCR units located in states that have approved permit programs or are otherwise subject to oversight through a permit program administered by the EPA. The first phase of the CCR rule amendments was made effective in August 2018 (the "Phase 1, Part 1 rule"). In addition to adopting alternative performance standards and revising groundwater performance standards for certain constituents, the EPA extended the deadline by which facilities must initiate closure of unlined ash ponds exceeding a groundwater protection standard and impoundments that do not meet the rule's aquifer location restrictions to October 2020.

Following the March 2019 submittal of competing motions from environmental groups, EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule") in September 2020. The rule reclassified compacted-soil lined surface impoundments from "lined" to "unlined," established a deadline of April 11, 2021, by which all unlined surface impoundments must initiate closure, and revised the alternative closure provisions to grant facilities additional time to initiate closure in order to manage CCR and non-CCR waste streams either due to a lack of alternative capacity or due to a commitment to close the coal-fueled operating unit and complete closure of unlined impoundments by a date certain. The Part A rule also revised certain requirements regarding annual groundwater monitoring and corrective action reports and publicly accessible CCR internet sites. A provision in Part A allows demonstrations to be submitted to the EPA allowing for operation of unlined CCR ponds beyond the April 11, 2021, deadline for initiation of closure. PacifiCorp has submitted alternative closure demonstrations for the Naughton South Ash Pond and the Jim Bridger flue gas desulfurization (FGD) Pond 2.

On October 16, 2020, the EPA released the pre-publication version of the final Holistic Approach to Closure: Part B rule ("Part B rule"). The Part B rule finalizes a two-step process, as set forth in the March 2020 proposal, allowing facilities to request approval to continue operating an existing unlined CCR surface impoundment with an alternate liner system. The other provisions that were contained in the Part B proposal, including (1) options to use CCR during closure of a CCR unit, (2) an additional closure-by-removal option and (3) new requirements for annual closure progress reports, were not finalized with the Part B rule. These options will be addressed by the EPA in a subsequent rulemaking action. In addition to the Part A and Part B rules, the EPA has proposed the Phase II rule, the federal CCR permit program rule, and the advanced notice of proposed rulemaking for legacy impoundments. Until the proposals are finalized and fully litigated, PacifiCorp cannot determine whether additional action may be required.

Separately, on August 10, 2017, the EPA issued proposed permitting guidance on how states' CCR permit programs should comply with the requirements of the final rule as authorized under the December 2016 Water Infrastructure Improvements for the Nation Act. To date, of the states in which PacifiCorp operates, only Wyoming has submitted an application to the EPA for approval of state permitting authority. The state of Utah adopted the federal final rule in September 2016, which required PacifiCorp to submit permit applications for two of its landfills by March 2017. It is anticipated that the state of Utah will submit an application to EPA for approval of its CCR permit program prior to the end of 2023. Wyoming finalized its rule in late 2020 and received legislative approval, in 2022. Wyoming submitted a primacy package to the EPA on February 6, 2023, and is awaiting primacy approval.

Water Quality Standards

Cooling Water Intake Structures

The federal Water Pollution Control Act (Clean Water Act) establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the “best technology available for minimizing adverse environmental impact” to aquatic organisms. In May 2014, EPA issued a final rule, effective October 2014, under § 316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule established requirements for electric generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from Waters of the United States (WOTUS) and use at least 25 percent of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from WOTUS for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, and Huntington generating facilities currently use closed-cycle cooling towers and withdraw more than two million, but less than 125 million, gallons of water per day. The rule includes impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards and entrainment (i.e., when organisms are drawn into the facility) standards. The standards will be set on a case-by-case basis to be determined through site-specific studies and will be incorporated into each facility's discharge permit.

Rule-required permit application requirements (PARs) have been submitted to the appropriate permitting authorities for the Jim Bridger, Naughton, Gadsby, Hunter and Huntington plants. As the five facilities utilize closed-cycle recirculating cooling water systems (cooling towers) exclusively for equipment cooling, it is expected that state agencies will require no further action from PacifiCorp to comply with the rule-required standards.

Because Dave Johnston utilizes once-through cooling with withdrawal rates greater than 125 million gallons per day, the facility has been required to conduct more rigorous PARs. The Dave Johnston PARs were submitted to the Wyoming Water Quality Division on May 31, 2019. The application proposed that no modifications to the intake structure were required; however, upon review of the submittal and subsequent issuance of a draft permit for public notice, the Water Quality Division has indicated that PacifiCorp may be required to select and implement an approved 316(b) impingement mortality compliance option by December 31, 2023. As the final Dave Johnston Wyoming Pollutant Discharge Elimination System permit has yet to be issued, which is expected to include 316(b) impingement mortality compliance requirements, it is anticipated that the December 31, 2023, impingement mortality technology implementation date will be adjusted to compensate for the actual permit issuance date.

Effluent Limit Guidelines

In November 2015, the EPA published final effluent limitation guidelines and standards (ELG) for the steam electric power generating sector which, among other things, regulate the discharge of bottom ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Under the originally promulgated guidelines, permitting authorities were required to include the new limits in each impacted facility's National Pollutant Discharge Elimination System (NPDES) permit upon renewal with the new limits to be met as soon as possible, beginning November 1, 2018 and fully implemented by December 31, 2023.

On April 5, 2017, a request for reconsideration and administrative stay of the guidelines was filed with the EPA. EPA granted the request for reconsideration and extended certain compliance dates for FGD wastewater and bottom ash transport water limits until November 1, 2020. On November 22, 2019, EPA proposed updates to the 2015 rule, specifically addressing FGD wastewater and bottom ash transport water. Those proposals were formalized in rule when the EPA administrator signed the Reconsideration Rule, and it was published in the Federal Register on October 13, 2020. The rule eases selenium limits on FGD wastewater, eases the zero-discharge requirements on bottom ash transport water associated with blowdown of ash handling systems, allows a two-year time extension to meet FGD wastewater requirements and includes additional subcategories to both wastewater categories.

Most of the issues raised by this rule are already being addressed at PacifiCorp facilities through compliance with the CCR rule and will not impose significant additional requirements on the facilities. The Dave Johnston plant submitted a notice of planned participation October 2021 for subcategorization for units ceasing coal combustion by December 31, 2028. Participation in the subcategory allows continued management of bottom ash transport water using impoundments and discharge of the waste stream., The plant requested that the option to transfer to the installation and operation of a bottom ash recycle system be included in the new NPDES permit.

EPA issued a proposed update to the ELG on March 7, 2023. PacifiCorp is evaluating the proposal and plans to submit comments.

Renewable Generation Regulatory Framework

Regulatory and permitting requirements for renewable energy projects are addressed at federal, state, and local levels. All wind projects in the United States must comply with federal regulations for wildlife impacts, aviation safety, clean water, communication systems, and Department of Defense impacts. Eagle Incidental Take Permits (EITPs), including associated surveys, monitoring, and compensatory mitigation, are necessary for wind projects that may result in take of bald or golden eagles. State and county regulations often address localized topics such as road and traffic concerns, community economic impacts, viewshed requirements, sage-grouse stipulations, wind turbine location guidelines, and land use and zoning restrictions. Solar projects must comply with federal and state regulations that restrict disturbance of certain flora and fauna and are subject to local planning and zoning regulations for land use. Storm water pollution prevention plans for renewable projects are usually required on a state level to control sediment runoff during construction and all renewable projects must comply with the Clean Water Act rules which are controlled at the federal level. Renewable energy projects located on federally managed lands or that receive federal funding are subject to National Environmental Policy Act (NEPA) review, which may include cultural and biological resource surveys, assessment of potential impacts, public comment periods, and avoidance/minimization/mitigation efforts. Power lines associated with renewable energy projects, including collector lines at the project site and grid-connecting transmission lines, may also be subject to environmental regulations, review, stipulations, or permits.

The wind projects constructed as part of PacifiCorp's Energy Vision 2020 initiative for example, (TB Flats, Ekola Flats, and Cedar Springs) were required to obtain permits from the State of Wyoming's Industrial Siting Division which required extensive studies of the conditions of the site, coordination with state agencies in the development process, and forecast of impacts from the project. Renewable energy projects in the State of Wyoming that meet the Industrial Siting Division's size or capital thresholds must obtain approval before they can begin construction. Most wind project developers coordinate with federal and/or state authorities to evaluate and mitigate potential impacts to birds or other wildlife species, particularly eagles, migratory birds, and bats, during the wind turbine siting process to minimize wildlife impacts and potential operational risks. Greater sage-grouse are currently managed by the states, and renewable energy projects and associated transmission lines would require state agency review; stipulations or mitigation requirements vary by state and project impacts. Because the generation capabilities of renewable energy projects are site specific and can vary greatly between different sites, understanding the specific permit requirements for each site is critical to developing a successful project.

Tax Extender Legislation

The 2021 IRP included a description of the Taxpayer Certainty and Disaster Relief Act of 2020. Among other things, the bill extended and expanded certain alternative energy tax credits. Extensions to this legislation have been subordinated by the Inflation Reduction Act, described above.

State Policy Update

California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. The first auction of greenhouse gas allowances was held in California in November 2012, and the second auction in February 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances and purchase the required allowances necessary to meet its compliance obligations.

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target. In July 2022, Governor Newsom outlined new targets and requested actions to accelerate progress on California's 2030 goals and 2045 carbon neutrality goals. In December 2022, CARB's final 2022 Scoping Plan was adopted laying out a path to achieve targets for carbon neutrality and reduce anthropogenic greenhouse gas emissions by 85 percent below 1990 levels no later than 2045, as directed by Assembly Bill 1279, passed in 2022.

In 2002, California established a RPS requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded a number of times since its inception. In September 2018, Governor Jerry Brown signed into law the 100 Percent Clean Energy Act of 2018, Senate Bill (SB) 100, which requires utilities to procure 60 percent of their electricity from renewables by 2030 and enabled all the state's agencies to work toward a longer-term planning target for 100 percent of California's electricity to come from renewable and zero-carbon resources by December 31, 2045. Interim targets for the carbon-free target were subsequently adopted by SB 1020 in 2022.

CARB adopted the Advanced Clean Cars II Rule in August of 2022. The rulemaking establishes that by 2035 all new passenger cars, trucks and SUVs sold in California will be zero emissions. The Advanced Clean Cars II regulations take the state's already growing zero-emission vehicle market and robust motor vehicle emission control rules and augments them to meet more aggressive tailpipe emissions standards and ramp up to 100% zero-emission vehicles.

Oregon

In 2007, the Oregon Legislature passed House Bill (HB) 3543 – Global Warming Actions, which establishes greenhouse gas reduction goals for the state that: (1) end the growth of Oregon greenhouse gas emissions by 2010; (2) reduce greenhouse gas levels to ten percent below 1990 levels by 2020; and (3) reduce greenhouse gas levels to at least 75 percent below 1990 levels by 2050. In 2009, the legislature passed SB 101, which requires the Public Utility Commission of Oregon (OPUC) to submit a report to the legislature before November 1 of each even-numbered year regarding the estimated rate impacts for Oregon's regulated electric and natural gas companies of meeting the greenhouse gas reduction goals of ten percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2014.

In 2007, Oregon enacted Senate Bill (SB) 838 establishing an RPS requirement in Oregon. Under SB 838, utilities are required to deliver 25 percent of their electricity from renewable resources by 2025. On March 8, 2016, Governor Kate Brown signed SB 1547-B, the Clean Electricity and Coal Transition Plan, into law. SB 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fueled resources are eliminated from Oregon's allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged—27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040. The bill changes the renewable energy certificate (REC) life to five years, while allowing RECs generated from the effective date of the bill passage until the end of 2022 from new long-term renewable projects to have unlimited life. The bill also includes provisions to create a community solar program in Oregon and encourage greater reliance on electricity for transportation.

On March 10, 2020, Oregon Governor Kate Brown issued Executive Order 20-04 (EO 20-04), which directs state agencies to take actions to reduce and regulate greenhouse gas emissions.

EO 20-04 establishes emissions reduction goals for Oregon and directs certain state agencies to take specific actions to reduce emissions and mitigate the impacts of climate change. EO 20-04 also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. HB 2021 also expanded the capacity standard for Small Scale Renewables from 8% to 10%. PacifiCorp's first Clean Energy Plan will discuss planning to meet these targets. PacifiCorp has convened a Community Benefits and Impacts Advisory Group in accordance with requirements.

In December 2022, Oregon Department of Environmental Quality adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. In Jan of 2022, HB 2165 passed requiring that all electricity companies (with ≥25,000 retail customers) recover the cost of prudent infrastructure investments in transportation electrification. Furthermore, in November 2021, Oregon adopted California's emission standards for HMDV via the Advanced Clean Truck Rules 2021, paving the way for Oregon to adopt a target of 100% of new MHDV sales being ZEVs by 2050.

Washington

In November 2006, Washington voters approved Initiative 937 (I-937), the Washington Energy Independence Act, which imposes targets for energy conservation and the use of eligible renewable resources on electric utilities. Under I-937, utilities must supply 15 percent of their energy from renewable resources by 2020. Utilities must also set and meet energy conservation targets starting in 2010.

In 2008, the Washington Legislature approved the Climate Change Framework E2SHB 2815, which establishes the following state greenhouse gas emissions reduction limits: (1) reduce emissions to 1990 levels by 2020; (2) reduce emissions to 25 percent below 1990 levels by 2035; and (3) by 2050, reduce emissions to 50 percent below 1990 levels or 70 percent below Washington's forecasted emissions in 2050.

In July 2015, Governor Inslee released an executive order that directed the Washington Department of Ecology to develop new rules to reduce carbon emissions in the state. In December 2017, Washington's Superior Court concluded that the Department of Ecology did not have the authority to impose the Clean Air Rule without legislative approval. As a result, the Department of Ecology has suspended the rule's compliance requirements.

In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA) which requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025, be carbon neutral by January 1, 2030, and establishes a target of 100 percent of its electricity from renewable and non-emitting resources by 2045.

In 2021, Washington passed the Climate Commitment Act, which establishes a cap-and-invest program that was implemented through the regulatory rulemaking process and came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities that are subject to CETA are allocated allowances within the cap-and-trade program at no cost, for emissions associated with Washington retail load. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.
In December 2022, Department of Ecology adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. Furthermore, in December 2021, Washington adopted California's emission standards for HMDV via the Advanced Clean Truck Rules 2021. In 2022, Department of Ecology passed the Clean Fuel Standard law requires fuel suppliers to gradually reduce the carbon intensity of transportation fuels to 20% below 2017 levels by 2034. There are several ways for fuel suppliers to achieve these reductions, including:

- Improving the efficiency of their fuel production processes

- Producing and/or blending low-carbon biofuels into the fuel they sell
- Purchasing credits generated by low-carbon fuel providers, including electric vehicle charging providers

Utah

In March 2008, Utah enacted the Energy Resource and Carbon Emission Reduction Initiative, which includes provisions to require utilities to pursue renewable energy to the extent that it is cost effective. It sets out a goal for utilities to use eligible renewable resources to account for 20 percent of their 2025 adjusted retail electric sales.

On March 10, 2016, the Utah legislature passed SB 115–The Sustainable Transportation and Energy Plan (STEP). The bill supports plans for electric vehicle infrastructure and clean coal research in Utah and authorizes the development of a renewable energy tariff for new Utah customer loads. The legislation establishes a five-year pilot program to provide mandated funding for electric vehicle infrastructure and clean coal research, and discretionary funding for solar development, utility-scale battery storage, and other innovative technology and air quality initiatives. The legislation also allows PacifiCorp to recover its variable power supply costs through an energy balancing account and establishes a regulatory accounting mechanism to manage risks and provide planning flexibility associated with environmental compliance or other economic impairments that may affect PacifiCorp's coal-fueled resources in the future. The deferrals of variable power supply costs went into effect in June 2016, and the five -year pilot program ran from January 1, 2017 through December 31, 2021.

In April 2019, the Utah Legislature passed HB 411, Community Renewable Program, that allowed cities and municipalities in Utah to elect to participate on behalf of their residents. The Community Renewable Program is an opt-out program with the goal of being 100% net renewable by 2030. Customers within a participating community may opt out of the program and maintain existing rates. The legislation prohibits cost shifting to non-participating customers. By the end of 2019, 23 Utah communities passed a resolution as required by the legislation to participate in the program. Program design efforts are underway and ongoing.

On March 11, 2020, the Utah Legislature passed HB 396, Electric Vehicle Charging Infrastructure Amendments, that enables PacifiCorp to create an Electrical Vehicle Infrastructure Program, with a maximum funding from customers of $50 million for all costs and expenses. The legislation allows PacifiCorp to own and operate electric vehicle charging stations and to provide investments in make-ready infrastructure to interested customers. The Public Service Commission of Utah approved the Electric Vehicle Infrastructure Program on December 20, 2021 for implementation on January 1, 2022. The program construct will undergo regulatory review every three years through 2032.

Wyoming

On March 8, 2019, Wyoming Senate File 0159 (SF 159) was passed into law. SF 159 limits the recovery costs for the retirement of coal fired electric generation facilities, provides a process for the sale of an otherwise retiring coal fired electric generation facility, exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility;

requires purchase of electricity generated from purchased retiring coal fired electric generation facility (as specified in final bill); and provides an effective date.

Cost recovery associated with electric generation built to replace a retiring coal fired generation facility shall not be allowed by the Wyoming Public Service Commission unless the Commission has determined that the public utility made a good faith effort to sell the facility to another person prior to its retirement and that the public utility did not refuse a reasonable offer to purchase the facility or the Commission determines that, if a reasonable offer was received, the sale was not completed for a reason beyond the reasonable control of the public utility.

Under SF 159 electric public utilities, other than cooperative electric utilities, shall be obligated to purchase electricity generated from a coal fired electric generation facility purchased under agreement approved by the Commission, provided the otherwise retiring coal fired electric generation facility offers to sell some or all of the electricity from the facility to an electric public utility, the electricity is sold at a price that is no greater than the purchasing electric utility's avoided cost, the electricity is sold under a power purchase agreement, and the Commission approves a 100 percent cost recovery in rates for the cost of the power purchase agreement and the agreement is 100 percent allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

In March 2020, the Wyoming legislature passed House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards. HB 200 required the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The requirement applies to generation allocated to Wyoming customers. HB 200 requires each public utility to demonstrate in its IRP the steps taken to achieve the electricity generation standard established by the Commission and will allow rate recovery of costs incurred by a public utility that utilizes coal-fired generation with carbon capture technology installed. The Wyoming Public Service Commission implemented new administrative rules Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023 and include a low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have greenhouse gas emission performance standards applicable to all electricity generated in the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 lb CO_2/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. In September 2018, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 925 lb CO_2/MWh.

Renewable Portfolio Standards

An RPS requires a retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources, such as wind, geothermal and solar energy. The retailer can satisfy this obligation by using renewable energy from its own facilities, purchasing renewable energy from another supplier's facilities, using Renewable Energy Credits (RECs) that certify renewable energy has been generated, or a combination of all of these.

RPS policies are currently implemented at the state level and vary considerably in their renewable targets (percentages), target dates, resource/technology eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and use of RECs.

In PacifiCorp's service territory, California, Oregon, and Washington have each adopted a mandatory RPS, and Utah has adopted a RPS goal. Each of these states' legislation and requirements are summarized in Table 3.3, with additional discussion below.

Table 3.3 – State RPS Requirements

	California	Oregon	Washington	Utah
Legislation	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011) • Senate Bill 350 (2015) • Senate Bill 100 (2018)	• Senate Bill 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009) • House Bill 1547-B (2016)	• Initiative Measure No. 937 (2006) • SB 5400 (2013)	• Senate Bill 202 (2008)
Requirement or Goal	• 20% by December 31, 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 • 44% by December 31, 2024 • 52% by December 31, 2027 • 60% by December 31, 2030 and beyond • Planning target of 100% renewable and zero-carbon by 2045 * Based on the retail load for a three-year compliance period	• 5% by December 31, 2011 • 15% by December 31, 2015 • 20% by December 31, 2020 • 27% by December 31, 2025 • 35% by December 31, 2030 • 45% by December 31, 2035 • 50% by December 31, 2040 * Based on the retail load for that year	• 3% by January 1, 2012 • 9% by January 1, 2016 • 15% by January 1, 2020 and beyond * Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective) • Annual targets are based on the adjusted[11] retail sales for the calendar year 36 months before the target year

California

California originally established its RPS program with passage of SB 1078 in 2002. Several bills that have since been passed into law to amend the program. In the 2011 First Extraordinary Special Session, the California Legislature passed SB 2 (1X) to increase California's RPS to 33 percent by 2020.[12] SB 2 (1X) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities. In October 2015, SB 350, the Clean Energy and Pollution Reduction Act, was signed into law.[13] SB 350 established a greenhouse gas reduction target of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 and expanded the state's renewables portfolio standard to 50 percent by 2030. In September 2018, the signing of SB 100,

[11] Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture storage and DSM.
[12] www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf
[13] leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

the Clean Energy Act of 2018, further expanded and accelerated the California RPS to 60 percent by 2030 and directed the state's agencies to plan for a longer-term goal of 100 percent of total retail sales of electricity in California to come from eligible renewable and zero-carbon resources by December 31, 2045.

SB 2 (1X) created multi-year RPS compliance periods, which were expanded by SB 100. The California Public Utilities Commission approved compliance periods and corresponding RPS procurement requirements, which are shown in Table 3.4 below.

Table 3.4 – California Compliance Period Requirements

Compliance Period	Procurement Quantity Requirement Calculation
Compliance Period 1 (2011-2013)	(20% * 2011 Retail Sales) + (20% * 2012 Retail Sales) + (20% * 2013 Retail Sales)
Compliance Period 2 (2014-2016)	(21.7% * 2014 Retail Sales) + (23.3% * 2015 Retail Sales) + (25% * 2016 Retail Sales)
Compliance Period 3 (2017-2020)	(27% * 2017 Retail Sales) + (29% * 2018 Retail Sales) + (31% * 2019 Retail Sales) + (33% * 2020 Retail Sales)
Compliance Period 4 (2021-2024)	(35.75% * 2021 Retail Sales) + (38.5% * 2022 Retail Sales) + (41.25% * 2023 Retail Sales) + (44% * 2024 Retail Sales)
Compliance Period 5 (2025-2027)	(46.67% * 2025 Retail Sales) + (49.33% * 2026 Retail Sales) + (52% * 2027 Retail Sales)
Compliance Period 6 (2028-2030)	(54.67% * 2028 Retail Sales) + (57.33% * 2029 Retail Sales) + (60% * 2030 Retail Sales)

SB 2 (1X) established new "portfolio content categories" for RPS procurement, which delineated the type of renewable product that may be used for compliance and also set minimum and maximum limits on certain procurement content categories that can be used for compliance.

Portfolio Content Category 1 includes eligible renewable energy and RECs that meet either of the following criteria:

> Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source;[11] or
>
> Have an agreement to dynamically transfer electricity to a California balancing authority.

Portfolio Content Category 2 includes firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.[14]

[14] A REC can be sold either "bundled" with the underlying energy or "unbundled" as a separate commodity from the energy itself into a separate REC trading market.

Additionally, the CPUC established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period as shown in Table 3.5.

Table 3.5 – California Balanced Portfolio Requirements

California RPS Compliance Period	Balanced Portfolio Requirement
Compliance Period 1 (2011-2013)	Category 1 – Minimum of 50% of Requirement Category 3 – Maximum of 25% of Requirement
Compliance Period 2 (2014-2016)	Category 1 – Minimum of 65% of Requirement Category 3 – Maximum of 15% of Requirement
Compliance Period 3 (2017-2020) Compliance Period 4 (2021-2024) Compliance Period 5 (2025-2027) Compliance Period 6 (2028-2030)	Category 1 – Minimum of 75% of Requirement Category 3 – Maximum of 10% of Requirement

In December 2011, the CPUC confirmed that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits in the three portfolio content categories. PacifiCorp is required to file annual compliance reports with the CPUC and annual procurement reports with the California Energy Commission (CEC). Neither SB 350 nor SB 100 changed the portfolio content categories for eligible renewable energy resources or the portfolio balancing requirements exemption provided to PacifiCorp. For utilities subject to the portfolio balancing requirements, the CPUC extended the compliance period 3 requirements through 2030.

The full California RPS statute is listed under Public Utilities Code Section 399.11-399.32. Additional information on the California RPS can be found on the CPUC and CEC websites. Qualifying renewable resources include solar thermal electric, photovoltaic, landfill gas, wind, biomass, geothermal, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels. Renewable resources must be certified as eligible for the California RPS by the CEC and tracked in the Western Renewable Energy Generation Information System (WREGIS).

Oregon

Oregon established the Oregon RPS with passage of SB 838 in 2007. The law, called the Oregon Renewable Energy Act, was adopted in June 2007, and provides a comprehensive renewable energy policy for the state.[15] Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet a target of at least 25 percent renewable energy by 2025. In March 2016, the Legislature passed SB 1547,[16] also referred to as Oregon's Clean Electricity and Coal Transition Act. In addition to requiring Oregon to transition off coal by 2030, the new law doubled Oregon's RPS requirements, which are to be staged at 27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040 and beyond. Other components of SB 1547 include:

[15] www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf
[16] olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

- Development of a community solar program with at least 10 percent of the program capacity reserved for low-income customers.
- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state's investor-owned utilities must come from small-scale renewable projects under 20 megawatts.
- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state's investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[17]

SB 1547 also modified the Oregon REC banking rules as follows:

- RECs generated before March 8, 2016, have an unlimited life.
- RECs generated during the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, have an unlimited life.
- RECs generated on or after March 8, 2016, from resources that came online before March 8, 2016, expire five years beyond the year the REC was generated.
- RECs generated beyond the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, expire five years beyond the year the REC is generated.
- RECs generated from projects coming online after December 31, 2022, expire five years beyond the year the REC is generated.
- Banked RECs can be surrendered in any compliance year regardless of vintage (eliminates the "first-in, first-out" provision under SB 838).

To qualify as eligible, the RECs must be from a resource certified as Oregon RPS eligible by the Oregon Department of Energy and tracked in WREGIS.
Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council geographic area, and a limited amount of unbundled renewable energy credits can be used toward the annual compliance obligation. Eligible renewable resources include electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, geothermal, certain types of biomass and biogas, municipal solid waste, and hydrogen power stations using anhydrous ammonia.

Electricity generated by a hydroelectric facility is eligible if the facility is not located in any federally protected areas designated by the Pacific Northwest Electric Power and Conservation Planning Council as of July 23, 1999, or any area protected under the federal Wild and Scenic Rivers Act, P.L. 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or if the electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995, and up to 50 average megawatts of electricity per year generated by a certified low-impact hydroelectric facility owned by an electric utility and up to 40 average megawatts of electricity per year generated by certified low-impact hydroelectric facilities not owned by electric utilities.

[17] In 2009, Oregon passed House Bill 3039, also called the Oregon Solar Initiative, requiring that on or before January 1, 2020, the total solar photovoltaic generating nameplate capacity must be at least 20 megawatts from all electric companies in the state. The Public Utility Commission of Oregon determined that PacifiCorp's share of the Oregon Solar Initiative was 8.7 megawatts.

PacifiCorp files an annual RPS compliance report by June 1 of every year and a renewable implementation plan on or before January 1 of even-numbered years, unless otherwise directed by the Public Utility Commission of Oregon. These compliance reports and implementation plans are available on PacifiCorp's website.[18]

The full Oregon RPS statute is listed in Oregon Revised Statutes (ORS) Chapter 469A and the solar capacity standard is listed in ORS Chapter 757. The Public Utility Commission of Oregon rules are in Oregon Administrative Rules (OAR) Chapter 860 Division 083 for the RPS and OAR Chapter 860 Division 084 for the solar photovoltaic program. The Oregon Department of Energy rules are under OAR Chapter 330 Division 160.

Utah

In March 2008, Utah's governor signed Utah SB 202, the Energy Resource and Carbon Emission Reduction Initiative.[19] The Energy Resource and Carbon Emission Reduction Initiative is codified in Utah Code Title 54 Chapter 17. Among other things, this law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions and for sales avoided because of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

Eligible renewable resources include electricity from a facility or upgrade that becomes operational on or after January 1, 1995, that derives its energy from wind, solar photovoltaic, solar thermal electric, wave, tidal or ocean thermal, certain types of biomass and biomass products, landfill gas or municipal solid waste, geothermal, waste gas and waste heat capture or recovery, and efficiency upgrades to hydroelectric facilities if the upgrade occurred after January 1, 1995. Up to 50 average megawatts from a certified low-impact hydro facility and in-state geothermal and hydro generation without regard to operational online date may also be used toward the target. To assist solar development in Utah, solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kWh of generation.

Under the Carbon Reduction Initiative, PacifiCorp is required to file a progress report by January 1 of each of the years 2010, 2015, 2020 and 2024.

PacifiCorp filed its most recent progress report on December 31, 2019. This report showed that the company is positioned to meet its 20 percent target requirement of approximately 4.8 million megawatt-hours of renewable energy in 2025 from existing company-owned and contracted renewable energy sources.

In 2027, the legislation requires a commission report to the Utah Legislature, which may contain any recommendation for penalties or other action for failure to meet the 2025 target. The legislation

[18] www.pacificpower.net/ORrps
[19] le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

requires that any recommendation for a penalty must provide that the penalty funds be used for demand side management programs for the customers of the utility paying the penalty.

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[20] The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

Eligible renewable resources include electricity produced from water, wind, solar energy, geothermal energy, landfill gas, wave, ocean, or tidal power, gas from sewage treatment facilities, biodiesel fuel with limitation, and biomass energy based on organic byproducts of the pulp and wood manufacturing process, animal waste, solid organic fuels from wood, forest, or field residues, or dedicated energy crops. Qualifying renewable energy sources must be located in the Pacific Northwest or delivered into Washington on a real-time basis without shaping, storage, or integration services. The only hydroelectric resource eligible for compliance is electricity associated with efficiency upgrades to hydroelectric facilities. Utilities may use eligible renewable resources, RECs, or a combination of to meet the RPS requirement.

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the Washington Utilities and Transportation Commission (WUTC) demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[21]

The WUTC adopted final rules to implement the initiative; the rules are listed in the Revised Code of Washington (RCW) 19.285 and the Washington Administrative Code (WAC) 480-109.

REC Management Practices

PacifiCorp provides the following summary of REC management practices in compliance with Order 20-186 in Oregon. The company intends to maximize the value of RECs for customers either through retirement for compliance purposes or monetization through sales. As a multi-state utility, PacifiCorp has Renewable Portfolio Standards in Washington, Oregon, and California, and a Renewable Portfolio Goal in 2025 in Utah. PacifiCorp generally retains and retires RECs allocated to Washington, Oregon, and California for compliance purposes, but requests flexibility to manage its RECs based on opportunities it sees in the market, which may include selling RECs at a favorable price and acquiring RECs at a lower price. The company maximizes the sale of RECs allocated to Utah, Idaho, and Wyoming and allocates the revenue from those sales to those states. One exception to REC sales is a special contract for one industrial customer where the customer foregoes REC sales revenue in exchange for a REC retirement to maintain renewable claims for corporate sustainability goals. An expansion of this program is currently under development to be offered under a new tariff in Utah, Idaho and Wyoming..

[20] www.secstate.wa.gov/elections/initiatives/text/I937.pdf
[21] www.pacificpower.net/report

Clean Energy Standards

Washington

In 2019, Governor Jay Inslee signed into law Senate Bill 5116, the Clean Energy Transformation Act. Under the law, Washington utilities are required to be carbon neutral by January 1, 2030 and institute a planning target of 100 percent clean electricity by 2045. The bill establishes four-year compliance periods beginning January 1, 2030 and requires utilities to use electricity from renewable resources and non-emitting electric generation in an amount equal to 100 percent of the retail electric load over each compliance period. Through December 31, 2044, an electric utility may satisfy up to 20 percent of its compliance obligation with an alternative compliance option such as the purchase of unbundled RECs.

Oregon

In July 2021, Oregon Governor Kate Brown signed into law House Bill 2021, which set emissions reduction targets for utilities and electricity providers. Under the law, retail electricity providers shall reduce greenhouse gas emissions by 80 percent below baseline emissions levels by 2030, by 90 percent below baseline emissions level by 2035, and by 100 percent below baseline emissions levels by 2040.

California

In 2018, California passed Senate Bill 100 – known as the "100 percent Clean Energy Act of 2018," which sets a 2045 goal of powering all retail electricity sold in California with renewable and zero-carbon resources. The law also updates the state's Renewables Portfolio Standard to ensure that by 2030 at least 60 percent of California's electricity is renewable.

In 2022, California passed Senate Bill 1020, the Clean Energy, Jobs, and Affordability Act of 2022. This bill established interim targets to the previously-established SB 100. It requires that eligible renewable energy resources and zero-carbon resources supply:

- 90% of all retail sales of electricity to California end-use customers by December 31, 2035
- 95% of all retail sales of electricity to California end-use customers by December 31, 2040
- 100% of all retail sales of electricity to California end-use customers by December 31, 2045
- 100% of electricity procured to serve all state agencies by December 31, 2030

In 2022, California passed Senate Bill 1158. This bill requires the State Energy Resources Conservation and Development Commission to adopt guidelines for the reporting and disclosure of electricity sources by the hour. The bill includes hourly power source reporting as a new set of reporting requirements at the Energy Commission and allows for the commission to modify those requirements for small entities with under 60,000 customers in California, like Pacific Power. Rulemaking is expected to occur before 2024.

Wyoming

In July 2020, House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards went into effect requiring the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The Wyoming Public Service Commission implemented rules for Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023 and include a final low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. The bill also allows electric utilities to implement a surcharge not to exceed 2% of customer bills to recover costs to comply with the standard.

Transportation Electrification

The electric transportation market is in an emerging state,[22] and plug-in electric vehicles (EV) currently comprise a negligible share of PacifiCorp's load. This rapidly evolving market represents a potential driver of future load growth and those impacts managed proactively, provide an opportunity to increase the efficiency of the electrical system and provide benefits for all PacifiCorp customers. In addition, increased adoption of electric transportation has the ability to improve air quality, reduce noise pollution, reduce greenhouse gas emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low- and moderate-income populations.

Current EV adoption numbers indicate that there is still an enormous opportunity for growth in the EV market. To develop a prospective forecast of EV adoption, PacifiCorp developed a model to assess trends for light duty vehicles (LDVs) and medium-duty and heavy-duty vehicles (M/HDVs). To inform a future vehicle adoption curve, the Company reviewed three national EV forecasts, each representing varying degrees of aggressiveness. While these forecasts represent national trends, the adoption curves themselves are quite different and can be adjusted to reflect state-specific parameters such as current market conditions, light duty truck saturation, and EV policies adopted in the state. PacifiCorp monitors vehicle adoption in each state on an annual basis and adjusts forecasts accordingly as new data is made available.

To help manage and understand the potential future load growth impacts of electric transportation PacifiCorp is investing to support EV fast chargers along key corridors, develop workplace charging programs, research new rate designs and implement time-of-use pricing pilots, create partnerships for smart mobility programs and develop opportunities for customers in our rural communities.

In California, Pacific Power's Electric Vehicle Infrastructure Rule 24 will pay for and coordinate the design and deployment of service extensions from our electrical distribution line facilities to the service delivery point for separately metered electric vehicle charging stations[23]. Pacific Power continues to provide programs funded by the Oregon Clean Fuels program as well as the recent HB 2165 legislation passed that created a transportation electrification benefits charge to support infrastructure development in the state of Oregon. As of November 2022, the Washington Utility and Transportation Commission approved Pacific Power's Transportation Electrification Plan which sets out an estimated spend of $3.5 million over the next five years to support TE in Washington state.

[22] As of June 2019, the market share of plug-in electric vehicles was three percent: https://joinyaa.com/guides/electric-vehicle-market-share-and-sales/
[23] California Electric Vehicle Infrastructure Line Extensions (pacificpower.net)

As of the end of 2022, PacifiCorp had supported installation of over 3,200 EV ports throughout the territory.

Electric vehicle load is reflected in the Company's load forecast. PacifiCorp continues to actively engage with local, regional, and national stakeholders and participate in state regulatory processes that can inform future planning and load forecasting efforts for electric vehicles

Hydroelectric Relicensing

The issues involved in relicensing hydroelectric facilities are multifaceted. They involve numerous federal and state environmental laws and regulations, and the participation of numerous stakeholders including agencies, Native American tribes, non-governmental organizations, and local communities and governments.

The value of relicensing hydroelectric facilities is continued availability of energy, capacity, and ancillary services associated with hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility because they can be called upon to meet peak customer demands almost instantaneously and back up intermittent renewable resources such as wind and solar with carbon-free generation. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation. Hydroelectric projects can also often provide important ancillary services, such as spinning reserve and voltage support, to enhance the reliability of the transmission system.

On September 27, 2019, the FERC issued a new license order for the Prospect No. 3 Hydroelectric Project, a 7.2 MW project located in southern Oregon. The license period is 40 years. Conditions of the license are consistent with the Commission's previous environmental analysis. Pursuant to the new license, PacifiCorp will implement increased minimum flows downstream of the diversion dam, replace the project's wood-stave flowline and sag-pipe, upgrade and construct new wildlife crossings over the waterway, and prepare and implement various monitoring and management plans.

On March 19, 2021, the FERC issued a new license order for the Weber Hydroelectric Project, a 3.85 MW project located in north central Utah. The license period is 40 years. Conditions of the license are consistent with the Commission's previous environmental analysis and are similar to previous license conditions. Pursuant to the new license, PacifiCorp will construct a new fish ladder at the diversion dam, complete recreation site improvements, annually provide four 4-hour whitewater boater flow releases and prepare and implement various monitoring and management plans.

On November 17, 2022, the FERC issued a license surrender order for the Lower Klamath Project, comprised of the J.C. Boyle, Copco No. 1, Copco No. 2, and Iron Gate hydroelectric developments with a combined nameplate capacity of 163 MW. Consistent with an earlier license transfer order issued by the FERC on June 17, 2021, the Klamath River Renewal Corporation and the states of California and Oregon accepted FERC's license surrender order and simultaneously accepted transfer of the Lower Klamath Project license and facilities from PacifiCorp on December 1, 2022. While PacifiCorp is no longer the owner of the Lower Klamath Project, PacifiCorp will continue to operate the facilities for the benefit of PacifiCorp customers under a contract with the KRRC until the facilities are removed. Generation from the Lower Klamath Project facilities is expected to cease at the end of 2023, and removal activities are anticipated to begin in the summer of 2023 at the Copco No. 2 development, with removal of the remaining developments in 2024.

The FERC hydroelectric relicensing process can be extremely political and often controversial. The process itself requires that the project's impacts on the surrounding environment and natural resources, such as fish and wildlife, be scientifically evaluated, followed by development of proposals and alternatives to mitigate those impacts. Stakeholder consultation is conducted throughout the process. If resolution of issues cannot be reached in this process, litigation often ensues, which can be costly and time-consuming. The usual alternative to relicensing is decommissioning. Both choices, however, can involve significant costs.

FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other criteria. FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural resources, recreation, land use, and aesthetics against the project's energy production benefits. Because some of the responsible state and federal agencies have the ability to place mandatory conditions in the license, FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency and the U.S. Fish and Wildlife Service have the authority in the relicensing process to require installation of fish passage facilities (fish ladders and screens) and to specify their design. This is often the largest single capital investment that will be considered in relicensing and can significantly impact project economics. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other, leading to potentially contrary or additive licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in negotiations with stakeholders to resolve complex relicensing issues. In some cases, settlement agreements are achieved which are submitted to FERC for incorporation into a new license. FERC welcomes license applications that reflect broad stakeholder involvement or that incorporate measures agreed upon through multi-party settlement agreements. History demonstrates that with such support, FERC generally accepts proposed new license terms and conditions reflected in settlement agreements.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2022, PacifiCorp had incurred approximately $32 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Cutler, Ashton and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, water quality, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. Much of these relicensing and settlement costs relate to PacifiCorp's two largest hydroelectric projects: Lewis River and North Umpqua.

Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Volume I, Chapter 7 (Resource Options).

PacifiCorp's Approach to Hydroelectric Relicensing

PacifiCorp continues to manage the hydroelectric relicensing process by pursuing interest-based resolutions or negotiated settlements as part of relicensing. PacifiCorp believes this proactive approach, which involves meeting agency and others' interests through creative solutions, is the best way to achieve environmental and social improvements while balancing customer costs and risks. PacifiCorp also has reached agreements with licensing stakeholders to decommission projects where that has been the most cost-effective outcome for customers.

Rate Design

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission of Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No 20-035-04 The goals for rate design are (generally) to reflect the cost to serve customers and to provide price signals to encourage economically efficient usage. This is consistent with resource planning goals that balance consideration of costs, risk, and long-run public policy goals. PacifiCorp currently has a number of rate design elements that take into consideration these objectives, in particular, rate designs that reflect cost differences for energy or demand during different time periods and that support the goals of acquiring cost-effective energy efficiency.

Residential Rate Design

Residential rates in Utah are comprised of a customer charge and energy charges. The customer charge is a monthly charge that provides limited recovery of customer-related costs incurred to serve customers regardless of usage and is broken into separate charges for residential customers who live in single family and multi-family dwellings All other remaining costs are recovered through volumetric- based energy charges. Energy charges for residential customers are designed with an inclining-tier rate structure so high usage during a billing month is charged a higher rate. Additionally, energy charges are differentiated by season with higher rates in the summer when the costs to serve are higher. Residential customers also have an option for time-of-day rates. Time-of-day rates have a surcharge for usage during the on-peak periods and a credit for usage during the off-peak periods. This rate structure provides an additional price signal to encourage customers to use less energy during the daily on-peak periods when energy costs are higher. As of November 2022, , less than one percent of customers have opted to participate in the time-of-day rate option.

. As part of the STEP legislation enacted in SB 115, the company developed a pilot time-of-use program to encourage off-peak charging of electric vehicles for residential customers. The results of this pilot may inform future rate design offerings. Any changes in standard residential rate design or institution of optional rate options to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs to ensure price signals are economically efficient and do not unduly shift costs to other customers.

Commercial and Industrial Rate Design

Commercial and industrial rates in Utah include customer charges, facilities charges, power charges (for usage over 15 kW) and energy charges. As with residential rates, customer charges and facilities charges are generally intended to recover costs that do not vary with energy usage. Power charges are applied to a customer's monthly demand on a kW basis and are intended to recover the costs associated with demand or capacity needs. Energy charges are applied to the customer's metered usage on a kWh basis. All commercial and industrial rates employ seasonal variations in power and/or energy charges with higher rates in the summer months to reflect the higher costs to serve during the summer peak period. Additionally, for customers with load 1,000 kW or more, rates are further differentiated by on-peak and off-peak periods for both power and energy charges. For commercial and industrial customers with load less than 1,000 kW, the company offers an optional time-of-day rates—one that differentiates energy rates for on- and off-peak usage,

Irrigation Rate Design

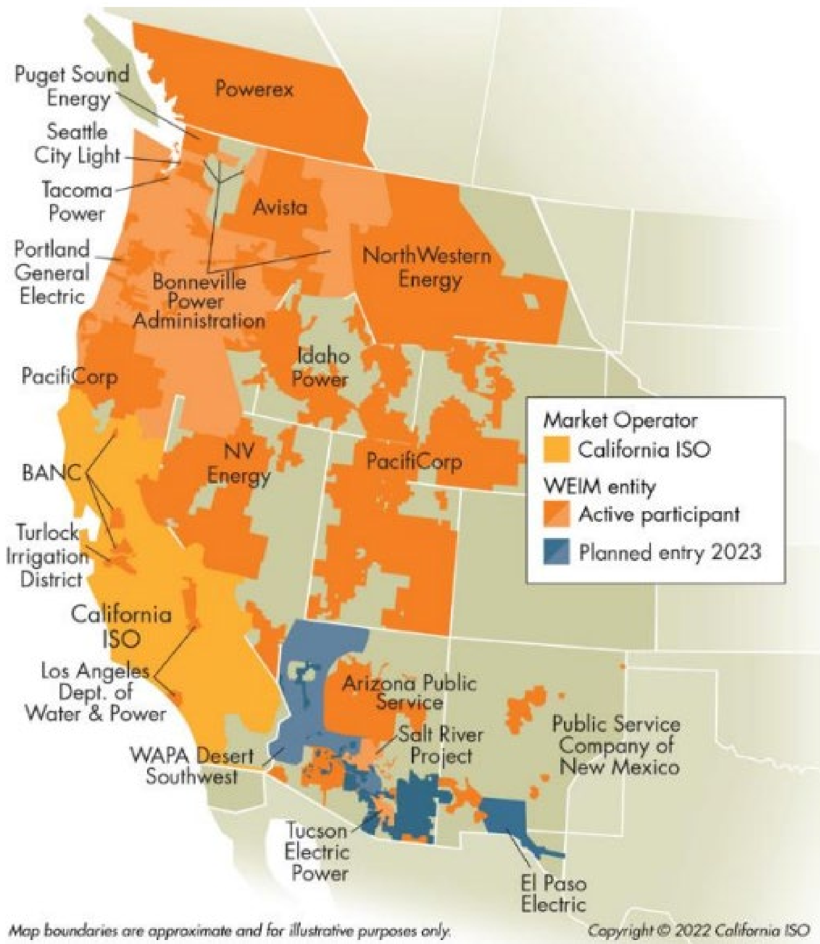
Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, a seasonal power charge, and energy charges. The annual and monthly customer charges provide some recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through a seasonal power charge and energy charges. The power charge is for the irrigation season only and is designed to recover demand-related costs and to encourage irrigation customers to control and reduce power consumption. Energy charges for irrigation customers are designed with two options. One is a time-of-day program with higher rates for on-peak consumption than for off-peak consumption. Irrigation customers also have an option to participate in a third-party operated Irrigation Load Control Program. Customers are offered a financial incentive to participate in the program and give the company the right to interrupt service to the participating customers when energy costs are higher.

Electricity Market Development Update

PacifiCorp and the CAISO launched the Western Energy Imbalance Market (WEIM) on November 1, 2014. The WEIM is a voluntary market and the first western energy market outside of California. NV Energy (NVE) began participating in December 2015, Arizona Public Service (APS) and Puget Sound Energy (PSE) began participating in October 2016, and Portland General Electric (PGE) began participating in October 2017. Idaho Power and Powerex began participating in April 2018, and the Balancing Authority of Northern California (BANC)[1] began participating in April 2019. Seattle City Light (SCL) and Salt River Project (SRP) began participating in April 2020, and 2021 saw the addition of NorthWestern Energy, Los Angeles Department of Water &

Power (LADWP), Public Service Company of New Mexico (PNM), and Turlock Irrigation District (TID). Avista Utilities, Tucson Electric Power (TEP), Tacoma Power and Bonneville Power Administration (BPA) officially became a participant in the EIM in 2022. In 2023, El Paso Electric and Western Area Power Administration Desert Southwest have planned entry into the WEIM. The WEIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, and British Columbia. PacifiCorp continues to work with the CAISO, existing and prospective WEIM entities, and stakeholders to enhance market functionality and support market growth.

Figure 3.9 – Western Energy Imbalance Market Expansion



The WEIM has produced approximately $3.4B in monetary benefits since inception for participating utilities , quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every 15 minutes and every five minutes within and across the EIM footprint; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexibility reserves in all WEIM balancing authority areas, also referred to as diversity benefits, which reduces cost by aggregating load, wind, and solar variability and forecast errors of the EIM footprint.

A significant contributor to EIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area to serve California load. The transfer volumes are therefore a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the five and 15-minute market dispatch intervals.

After development and expansion of the WEIM in the west, a natural next question was – are there continued opportunities to increase economic efficiency and renewable integration beyond the scope of WEIM but short of a fully regional independent system operator? PacifiCorp believes the answer is ‘yes’.

Over the duration of 2022, the CAISO held a robust stakeholder process to develop the market design of the Extended Day-Ahead Market (EDAM). With stakeholder feedback, the final EDAM proposal was released in early December 2022. On December 8th, PacifiCorp announced that it intends to join EDAM. The final EDAM design was approved by the CAISO Board of Governors and WEIM Governing Body in early February 2023, and CAISO plans to file the EDAM tariff with FERC mid-2023. EDAM is tentatively scheduled to go live in 2025.

The Southwest Power Pool (SPP) has also been developing a day-ahead market offering, called Markets+. Markets+ introduces a potential risk to WEIM benefits through a shrinking WEIM footprint because participation in Markets+ would require entities to exit WEIM. SPP and stakeholders are aiming to deliver the Markets+ tariff to FERC before the end of this year. With competing day-ahead and real-time markets emerging in the West, seams issues are naturally emerging.

Recent Resource Procurement Activities

PacifiCorp issued and will issue multiple requests for proposals (RFP) to secure resources or transact on various energy and environmental attribute products. Table 3.6 summarizes recent RFP activities.

Table 3.6 – PacifiCorp's Requests for Proposal Activity

RFP	RFP Objective	Status	Issued	Completed
2019R Utah RFP	Purchase new renewable energy for specific customers under Utah Schedule 32 or 34	Closed	March 2019	2019
Renewable energy credits (Purchase)	Excess system RECs	Ongoing	Based on specific need	Ongoing
2019 Capacity and Energy Supply RFP	Purchase capacity and energy supply	Closed	June 2019	2019
Renewable energy credits (Purchase)	Oregon compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Washington compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Ongoing	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Ongoing	Based on specific need	Ongoing
2020 All-Source RFP	Seeking resources consistent with the 2019 IRP's least cost resource portfolio	Closed	July 2020	2022
2021 DR RFP	Oregon compliance and purchase of cost-effective flexible capacity	On-going	January 2021	2022
2022 Carbon Capture, Utilization and Sequestration (CCUS) RFPs	Two concurrent RFPs for CCUS facilities to remove, sequester or utilize carbon dioxide (CO2) from exhaust gases at two of PacifiCorp's Wyoming coal-fueled generation facilities	On-going	October 2022	2023
2022 All-Source RFP	Seeking resources consistent with the 2021 IRP's least cost resource portfolio	On-going	May 2022	Expected in Q4 2023

2020 All-Source RFP

PacifiCorp's 2020 All Source RFP ("2020AS RFP") was filed for approval with the Utah PSC and the Oregon PUC in April 2020. In July 2020, the Utah PSC and the Oregon PUC approved the 2020AS RFP, and PacifiCorp issued the 2020AS RFP to market. The 2020AS RFP sought bids for resources capable of coming online by the end of 2024 up to the level of resources identified in PacifiCorp's 2019 IRP. Bids were submitted in August 2020. An initial shortlist was identified in October 2020. The initial shortlist includes a total of 6,982 MWs of new generation and storage capacity. Of the total, 5,652 MWs are new generation resources (represented by 3,173 MWs of solar generation and 2,479 MWs of wind generation) and an additional 1,330 MWs of new battery storage assets, which includes 1,130 MWs of solar collocated battery storage and 200 MWs of stand-alone battery storage.

The final shortlist of winning bids was identified by June 2021 and was comprised of 1,792 MW of wind generation, 95 MW of solar generation, 1,211 MW of solar generation collocated storage and 200 MW of stand-alone battery storage; 590 MW of wind generation is being contracted as a build and transfer to PacifiCorp with the balance of the generation contracted through long-term power purchase agreements.

PacifiCorp is finalizing the build and transfer agreement for 590 MW and has finalized power purchase agreements for 1,202 MW new wind resources, 495 MW new solar resources with 200 MW new collocated battery energy storage resources. . All necessary state regulatory approvals are complete.

2021 DR RFP

On February 8, 2021, PacifiCorp issued an RFP soliciting proposals from implementation contractors for Demand Response (DR) resources. Although a variety of programs were eligible for consideration, of most interest to PacifiCorp were programs located in Oregon and/or Washington with the following focus:

- Non-Residential Curtailment
- Residential and/or Small Commercial Smart Thermostat or Water Heaters
- Irrigation load control

The final shortlist of bids was identified in June 2021 and includes over 600 MW of capacity during the 20-year planning horizon across all of PacifiCorp’s six states. Additionally, the 2021 IRP update selected almost 1000 MW of cost-effective demand response over the planning horizon. PacifiCorp procured and negotiated demand response resources following the to meet near-term demand response needs.

2022 All-Source RFP

PacifiCorp's 2022 All Source RFP ("2022AS RFP") was filed for approval with the Washington WUTC, Utah PSC and the Oregon PUC by January 2022. By April 2022, all three states had approved the 2022AS RFP, and it was issued to market on April 29, 2022. Consistent with the 2021 IRP, the 2022AS RFP sought bids resources capable of coming online by the end of 2026; however, regulatory approval required the Company to accept eligible bids which demonstrate their ability to be operational and deliver firm energy by December 31, 2027, or December 31, 2028 for long-lead time resources such as pumped storage hydro, geothermal and nuclear resources. The 2022AS RFP will consider resources:

- Point of Delivery: capable of interconnecting with or delivering to PacifiCorp's transmission system in its east or west balancing authority areas (PACE and PACW, respectively).
- Ownership structure: benchmark, build-transfer, power purchase and tolling agreement for
- Technology type: "All source" Any generating and storage resource type as well as professional services contracts for resources such as demand response resource proposals
- Term length: 5 and 30 years.

PacifiCorp received twelve eligible self-build (benchmark) resources on December 2, , and on March 14, 2023, PacifiCorp received 302 bids from 74 developers and 93 different projects sites across six states. A final shortlist is expected by late Q2 2023, early Q3 2023 with resources contracted by the end of Q4 2023. All necessary final state regulatory approvals and proceedings are expected to be complete by Q4 2023.

PacifiCorp anticipates a similar all source RFP will be required as an action item out of this 2023 IRP.

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp's planned transmission projects help facilitate a transitioning resource portfolio and comply with reliability requirements, while providing sufficient flexibility necessary to ensure existing and future resources can meet customer demand cost effectively and reliably.
- Given the long lead time needed to site, permit, and construct new transmission lines, these projects need to be planned well in advance of resource additions.
- PacifiCorp's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and respond to commission and stakeholder requests for a robust evaluation process and clear criteria for evaluating transmission additions.
- The 2023 IRP preferred portfolio includes the following notable transmission upgrades:
    - The Energy Gateway South transmission line - a new 416-mile, high-voltage 500-kilovolt transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The new transmission line will come online by the end of 2024.
    - The Energy Gateway West Subsegment D1 project - a new high-voltage 230-kilovolt transmission line and a rebuild of an existing 230-kilovot transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.
    - The Energy Gateway Segment H Boardman to Hemingway line - an approximately 290-mile, high-voltage 500-kilovolt transmission line and associated infrastructure running from the proposed Longhorn substation near Boardman, Oregon and the Hemingway substation near Melba, Idaho, which is targeting to come online in 2026.
    - The Energy Gateway West Subsegment D3 – a new 200-mile, high voltage 500-kilovolt transmission line and associated infrastructure running from Anticline substation in central Wyoming to Populus substation in southeastern Idaho. The transmission line is targeted to come online in 2028.
    - A new, 150-mile, high voltage 500-kilovolt transmission line running from Anticline substation to Shirley Basin substation. The transmission line is targeted to come online in 2028.
- Further, the 2023 IRP preferred portfolio includes near-term transmission upgrades across PacifiCorp's transmission system including investment in infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming that will facilitate continued and long-term growth in new resources needed to serve PacifiCorp's customers.

Introduction

PacifiCorp's bulk transmission network is a high-value asset that is designed to reliably transport electric energy from a broad array of generation resources (owned or contracted generation including market purchases) to load centers. There are many benefits associated with a robust transmission network, some of which are set forth below:

1. Reliable delivery of diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to always meet aggregate electrical demand and customers' energy requirements, considering scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Ability to meet changing regulatory requirements as states move towards a renewable energy future.
4. Economic dispatch of resources within PacifiCorp's diverse system.
5. Economic transfer of electric power to and from other systems as facilitated by the company's participation in the market, which reduces net power costs and provides opportunities to maintain resource adequacy at a reasonable cost.
6. Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
7. Resiliency to protect against system and market disruptions where limited transmission can otherwise constrain energy supply.
8. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).

PacifiCorp's transmission network is highly integrated with other transmission systems in the west and provides the critical infrastructure needed to serve our customers cost effectively and reliably. Consequently, PacifiCorp's transmission network is a critical component of the IRP process. PacifiCorp has a long history of providing reliable service in meeting the bulk transmission needs of the region. This valued asset will become even more critical as the regional resource mix transitions to accommodate increasing levels of variable generation from renewable resources that will be used to serve the growing energy needs of our customers.

This chapter provides:

- An overview of PacifiCorp's regulatory requirements including recent updates to PacifiCorp's generation interconnection procedures.
- Justification supporting acknowledgement of PacifiCorp's plan to construct the Gateway South, Gateway West Subsegments D1 and D3, Gateway Segment H Boardman-to-Hemingway and the Anticline-Shirley Basin transmission lines.
- Support for PacifiCorp's plan to continue permitting the balance of Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of PacifiCorp's investments in recent short-term system improvements that have improved reliability, helped to maximize efficient use of the existing system, and enabled the company to defer the need to invest in larger-scale transmission infrastructure.

Regulatory Requirements

Open Access Transmission Tariff

Consistent with the requirements of its OATT, approved by the Federal Energy Regulatory Commission (FERC), PacifiCorp plans and builds its transmission system based on two customer-type agreements—network customer or point-to-point transmission service. For network customers, PacifiCorp uses ten-year load-and-resource (L&R) forecasts supplied by the customer, as well as network transmission service requests to facilitate development of transmission plans. Each year, PacifiCorp solicits L&R data from each of its network customers to determine future

L&R requirements for all transmission network customers. The bulk of PacifiCorp's network customer needs comes from the company's Energy Supply Management (ESM) function, which supplies energy and capacity for PacifiCorp's retail customers. Other network customers include Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative (including Moon Lake Electric Association), Bonneville Power Administration (BPA), Basin Electric Power Cooperative, Black Hills Power, Tri-State Generation & Transmission, the United States Department of the Interior Bureau of Reclamation, and the Western Area Power Administration.

PacifiCorp uses its customers' L&R forecasts and best available information, including transmission service and generation interconnection requests, as factors to determine the need and timing for investments in the transmission system. If customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios or schedules for transmission system investments, as appropriate. In accordance with FERC guidelines, PacifiCorp is able to reserve transmission network capacity based on these data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required to deliver significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of L&R forecasts.[1] A 20-year planning horizon and ability to reserve transmission capacity to meet existing and forecasted need over that timeframe is more consistent with the time required to plan for and build large-scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

For point-to-point transmission service, the OATT requires PacifiCorp to grant service on existing transmission infrastructure using existing capacity or to build transmission system infrastructure as required to provide the service. The required action is determined with each point-to-point transmission service request through FERC-approved study processes that identify the transmission need.

Reliability Standards

PacifiCorp is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by California Independent System Operator (CAISO) RC West as the NERC Reliability Coordinator. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to always meet aggregate electrical demand for customers. Security is the electric system's ability to

[1] For example, PacifiCorp's application to begin the Environmental Impact Statement (EIS) process for the Gateway West segment of its Energy Gateway Transmission Expansion Project was filed with the Bureau of Land Management (BLM) in 2007. A partial Record of Decision (ROD) was received in late April 2013, and a supplemental ROD was received in January 2017.

withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

Generation Interconnection Cluster Study Process

In 2020, PacifiCorp transitioned from a serial queue generation interconnection process to a first ready, first served cluster study process. The new procedures require interconnection customers to provide increasing readiness demonstrations throughout the study process to facilitate projects that have a clearer path forward to proceed through the process while at the same time applying financial penalties to those customers who withdraw speculative generation interconnection requests. As part of PacifiCorp's transition to cluster studies the existing serial queue requests that were able to demonstrate readiness were provided an opportunity to participate in a transition cluster study. In the transition cluster study 56 requests totaling approximately 4260 megawatts were entered into the process and evaluated. Of those, 19 requests for approximately 1,400 megawatts have proceeded through the process, the majority of which have signed interconnection agreements. In PacifiCorp's first annual cluster study, which commenced in June 2021, 59 requests were received totaling approximately 12,000 megawatts were submitted and evaluated. Of those, 22 requests totaling approximately 4,500 megawatts have continued through the study process, most of which have signed interconnection agreements. In PacifiCorp's second annual cluster study, which commenced in June 2022, 199 requests were received totaling approximately 40 gigawatts. Approximately half of those requests were withdrawn following the completion of the cluster study with the remaining proceeding through the next steps of the cluster study process. The interconnection requests currently in PacifiCorp's process include solar, wind, nuclear, geothermal, pump storage, battery storage and hybrid resources with both an underlying fuel source paired with storage.

Generation Interconnection Study Methodology Changes

In 2021 PacifiCorp filed a request with FERC to modify its Large Generator Interconnection Procedures (LGIP) to allow PacifiCorp to study new generation interconnection requests using historically available generation data from operating resources. The request was approved by FERC in 2022 and the new assumptions were implemented into PacifiCorp's 2022 cluster study. This allowed PacifiCorp to use more realistic study assumptions from existing resources rather than assume worst case scenario assumptions which in some circumstances should alleviate the need for additional network upgrades to interconnect new resources.

In 2022 PacifiCorp filed a request with FERC to modify its LGIP to allow PacifiCorp to study new standalone storage resources as not discharging during high generation of other resources in the region. The request was approved by FERC in March 2022 and the new assumptions will be implemented into future generation interconnection studies. This will allow PacifiCorp to use more realistic study assumptions for storage resources which in some circumstances should alleviate the need for additional network upgrades to interconnect new resources. To facilitate additional reliability and the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes significant transmission investment. Specifically, the 2023 IRP preferred portfolio includes:

- Energy Gateway Segment F – Gateway South (Aeolus-Mona/Clover) 500 kV transmission line

- Energy Gateway Segment D1 (Shirly Basin-Windstar) 230 kV transmission line and 230 kV line rebuild
- Energy Gateway Segment D3 (Anticline-Populus) 500 kV line
- Anticline-Shirley Basin 500 kV transmission line

Aeolus to Mona/Clover (Gateway South – Segment F)

The 2023 PacifiCorp IRP preferred portfolio includes the Aeolus-to-Mona (Clover substation) transmission segment (Energy Gateway South or Segment F).

The Energy Gateway South transmission line is a new 416-mile, high-voltage 500-kilovolt transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The transmission line is currently under construction and scheduled to come online by the end of 2024.

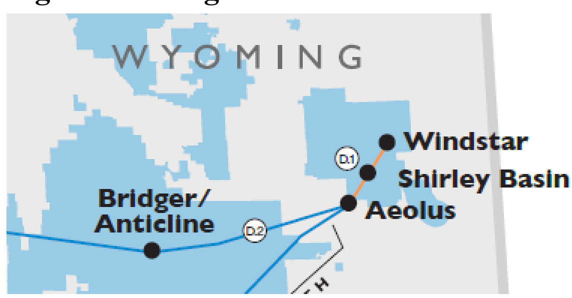
Windstar-Populus (Gateway West – Segment D)

The Windstar-to-Populus transmission project consists of three key sub-segments:

- D1— Currently under construction, a single-circuit 230-kV line running approximately 59 miles between the existing Windstar and Aeolus substations in eastern Wyoming;

- D2—A single-circuit 500-kV line completed October 2020 and energized November 2020 and

Figure 4.1 - Segment D



- D3—A single-circuit 500-kV line running approximately 200 miles between the new Anticline substation and the Populus substation in southeast Idaho.

The 2023 preferred portfolio includes the Energy Gateway West Subsegment D.1 project which consists of a new 230 kV line and a rebuild of an existing 230 kV line between the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines are currently under construction and scheduled to come online by the end of 2024.

Populus-Hemingway (Gateway West - Segment E)

The Populus-to-Hemingway transmission project consists of two single-circuit 500-kV lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho.
While PacifiCorp is not requesting acknowledgement of a plan to construct these segments in this IRP, the company will continue to permit the projects.

Figure 4.2 - Segment E

The Gateway West Segment E project would enable PacifiCorp to more efficiently dispatch system resources, improve performance of the transmission performance of the transmission system performance (i.e., reduce line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long term.

Plan to Continue Permitting – Gateway West

The Gateway West transmission projects continue to offer benefits under multiple, future resource scenarios. To ensure the Company is well positioned to advance the projects, it is prudent for PacifiCorp to continue to permit the balance of Gateway West transmission projects. The Records of Decision and rights-of-way grants contain many conditions and stipulations that must be met and accepted before a project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management to review progress.

Boardman-Hemingway (Segment H)

The 2023 IRP preferred portfolio includes an approximately 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway to come online in 2026.

PacifiCorp continues to participate in the project under the Joint Funding Permitting Agreement with Idaho Power and BPA. In accordance with this agreement, PacifiCorp is responsible for its share of the costs associated with federal and state permitting activities and other pre-construction activities agreed to in the updated agreement.

Idaho Power's 2019 IRP identified the Boardman-to-Hemingway transmission line (B2H) as a preferred resource to meet its capacity needs, reflecting a need for the project in 2026 to avoid a deficit in load-serving capability in peak-load periods. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line to be in 2026 or beyond.

The BLM released its ROD for B2H on November 17, 2017. The ROD allows BLM to grant right-of-way to Idaho Power for the construction, operation, and maintenance of the B2H Project on BLM-administered land. The BLM right-of-way grant was executed on January 9, 2018.

The U.S. Forest Service (USFS) issued a separate ROD on November 9, 2018 for lands administered by the USFS based on the analysis in the final EIS. The USFS ROD approves the issuance of a special-use authorization for a portion of the project that crosses the Wallowa-Whitman National Forest. The U.S. Department of the Navy issued a ROD on September 25, 2019 in support of construction of a portion of the B2H project on 7.1 miles of the Naval Weapons Systems Training Facility in Boardman, Oregon.

On September 27, 2022, Oregon's Energy Facility Siting Council approved the Oregon site certificate completing Oregon's permit actions that provide for the construction of the project across private lands in Oregon. Following this action an appeal was made to the Oregon

Supreme court challenging the approval. On March 8, 2023, the court affirmed the site certificate which finalized the site certificate.

In January of 2022 Idaho Power, Bonneville Power Administration and PacifiCorp agreed in a non-binding term sheet to negotiate Bonneville's exit of the project with Idaho Power acquiring Bonneville's share responsibility of the project. This will provide Idaho Power with a 45% share of the project and retain PacifiCorp's 55% share. Additional terms under negotiations include changes in transmission service between PacifiCorp and Bonneville; between Bonneville and Idaho Power, as well as the purchase and sale of certain assets between Idaho Power and PacifiCorp. The Boardman to Hemingway amended Permit Funding Agreement removing Bonneville and updating the agreement to capture additional pre-construction tasks was executed on March 23, 2023. The Joint Purchase and Sale agreement between Idaho Power and PacifiCorp provides Idaho Power with certain assets allowing service to Bonneville Power customers in southeast Idaho via the Boardman to Hemingway line, and capacity from the Four Corners substation in New Mexico to the Populus substation in southern Idaho. Associated with the term sheet is the Hemingway project construction agreement, construction agreements for upgrades that provide PacifiCorp additional capacity across Idaho Power's transmission system and a construction agreement that provides PacifiCorp additional capacity to serve central Oregon loads. These agreements were all executed on March 23, 2023 and will become effective once the Federal Energy Regulatory Commission approves the agreements.

Idaho Power has applied for Certificates of Public Convenance and Necessity in Oregon and Idaho. Issuance of both Certificates are expected in June of 2023. PacifiCorp has applied for Certificates of Public Convenance and Necessity in Idaho and Wyoming, no schedule for completion has been set.

The current project schedule includes a construction start date in July of 2023 with completion mid-year 2026.
Given the extensive list of benefits noted above, PacifiCorp is committed to participating in the Boardman-to-Hemingway project in accordance with the terms of the Joint Funding Permitting Agreement through pre-construction activities and negation of the three party terms, and will continue to work with Idaho Power in the development and negotiations of the definitive agreement for the construction and ownership of the new line. PacifiCorp continues to evaluate the benefits to PacifiCorp's customers prior to commitment of entering into a project construction agreement. Additionally, PacifiCorp will continue to review possible benefits of the project as it continues to participate in project development activities, including moving forward with preliminary construction and construction agreement negotiations.

Anticline-Shirley Basin Transmission Line

The 2023 preferred portfolio includes the construction of a new, approximately 150-mile, 500 kV transmission line between Shirley Basin and Anticline substations. PacifiCorp has begun the federal permitting process for this new transmission line and is currently targeting an in-service date in 2028 for the line.

Other Transmission System Improvements

The 2023 IRP preferred portfolio further also includes near-term transmission upgrades across its transmission system. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources and increased reliability for its customers.

Energy Gateway Transmission Expansion Plan

Introduction

Given the long–lead time required to successfully site, permit and construct major new transmission lines, these projects need to be planned well in advance. The Energy Gateway Transmission Expansion Plan is the result of several robust local and regional transmission planning efforts that are ongoing and have been conducted multiple times over a period of several years. The purpose of this section is to provide important background information on the transmission planning efforts that led to PacifiCorp's proposal of the Energy Gateway Transmission Expansion Plan.

Background

Until PacifiCorp's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered on new resource additions identified in the IRP. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proving to be problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable for meeting customer needs. The existing transmission system has been at capacity for several years, and new capability is necessary to enable new resource development.

The Energy Gateway Transmission Expansion Plan, formally announced in May 2007, has origins in numerous local and regional transmission planning efforts discussed further below. Energy Gateway was designed to ensure a reliable, adequate system capable of meeting current and future customer needs. Importantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across PacifiCorp's multi-state service area. In addition, the ability to use these resource-rich areas helps position PacifiCorp to meet current state renewable portfolio requirements. Energy Gateway has since been included in all relevant local, regional and interconnection-wide transmission studies.

Planning Initiatives

Energy Gateway is the result of robust local and regional transmission planning efforts. PacifiCorp has participated in numerous transmission planning initiatives, both leading up to and since Energy Gateway's announcement. Stakeholder involvement has played an important role in each of these initiatives, including participation from state and federal regulators, government agencies, private and public energy providers, independent developers, consumer advocates, renewable energy groups, policy think tanks, environmental groups, and elected officials. These studies have shown a critical need to alleviate transmission congestion and move constrained energy resources to regional load centers throughout the west, and include:

- ***Rocky Mountain Area Transmission Study***
  Recommended transmission expansions overlap significantly with Energy Gateway configuration, including:
  - Bridger system expansion similar to Gateway West.
  - Southeast Idaho to southwest Utah expansion akin to Gateway Central, Segment B, Segment C and Sigurd to Red Butte (in service 2015).
  - Improved east-west connectivity similar to Energy Gateway Segment H alternatives.

> "The analyses presented in this Report suggest that well-considered transmission upgrades, capable of giving LSEs greater access to lower cost generation and enhancing fuel diversity, are cost-effective for consumers under a variety of reasonable assumptions about natural gas prices."

- ***Western Governors' Association Transmission Task Force Report***
  Examined the transmission needed to deliver the largely remote generation resources contemplated by the Clean and Diversified Energy Advisory Committee. This effort built upon the transmission previously modeled by the Seams Steering Group-Western Interconnection and included transmission necessary to support a range of resource scenarios, including high efficiency, high renewables and high conventional resource scenarios. Again, for PacifiCorp's system, the transmission expansion that supported these scenarios closely resembled Energy Gateway's configuration.

> "The Task Force observes that transmission investments typically continue to provide value even as network conditions change. For example, transmission originally built to the site of a now obsolete power plant continues to be used since a new power plant is often constructed at the same location."

- ***Northern Tier Transmission Group Transmission Planning Reports***
  In the 2020-2021 NTTG Draft Regional Transmission Plan, sub segments of Energy Gateway (both Gateway West and Gateway South) were listed as necessary to provide acceptable system performance. The study also established that the amount of new Wyoming wind generation that is added over time can impact the transmission system reliability west of Wyoming. Additionally, three interregional projects were included in the study the Southwest Inter-tie Project (SWIP North), Cross Tie and TransWest Express, which showed that all three projects relied on Energy Gateway to attain their full transfer capability rating.

> "After analyzing the steady-state performance of stressed conditioned cases, a rigorous contingency analysis commenced… then, NTTG's Technical Committee determined additional facilities would be needed to meet the reliability criteria…."

- ***WECC/Reliability Assessment Committee (RAC) Annual Reports* and *Western Interconnection Transmission Path Utilization Studies***
  These analyses measure the historical use of transmission paths in the west to provide insight into where congestion is occurring and assess the cost of that congestion. The Energy Gateway segments were included in the analyses that support these studies, alleviating several points of significant congestion on the system, including Path 19 (Bridger West) and Path 20 (Path C).

"Path 19 [Bridger] is the most heavily loaded WECC path in the study…. Usage on this path is currently of interest due to the high number of requests for transmission service to move renewable power to the West from the Wyoming area."

Energy Gateway Configuration

To address constraints identified on PacifiCorp's transmission system, as well as meeting system reliability requirements discussed further below, the recommended bulk electric transmission additions took on a consistent footprint, which is now known as Energy Gateway. This expansion plan establishes a triangle of reliability that spans Utah, Idaho and Wyoming with paths extending into Oregon and Washington. This plan contemplates geographically diverse resource locations based on environmental constraints, economic generation resources, and federal and state energy policies.

Since Energy Gateway's initial announcement in 2007, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and Western Interconnection level. In accordance with the local planning requirements in PacifiCorp's OATT, Attachment K, PacifiCorp has conducted numerous public meetings on Energy Gateway and transmission planning in general. Meeting notices and materials are posted publicly on PacifiCorp's Attachment K Open Access Same-time Information System (OASIS) site. PacifiCorp is also a member of NorthernGrid regional planning organization and WECC's Reliability Assessment Committee and was formally a member of Northern Tier Transmission Group (NTTG) regional planning organization.

These groups continually evaluate PacifiCorp's transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp's OASIS site for information and materials related to these public processes.[2]

Additionally, an extensive 18-month stakeholder process on Gateway West and Gateway South was conducted. This stakeholder process was conducted in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles, and was used to establish need, assess benefits to the region, vet alternatives, and eliminate duplication of projects. Meeting materials and related reports can be found on PacifiCorp's Energy Gateway OASIS site.

Energy Gateway's Continued Evolution

The Energy Gateway Transmission Expansion Plan is the product of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since its announcement in May 2007, Energy Gateway's scope and scale have continued to evolve

[2] http://www.oatioasis.com/ppw/index.html

to meet the future needs of PacifiCorp customers and the requirements of mandatory transmission planning standards and criteria. Additionally, PacifiCorp has improved its ability to meet near-term customer needs through a limited number of smaller-scale investments that maximize efficient use of the current system and help defer, to some degree, the need for larger capital investments like Energy Gateway (see the following section titled "Efforts to Maximize Existing System Capability"). The IRP process, as compared to transmission planning, can result in frequent changes in the least-cost, least-risk resource plan driven by changes in the planning environment (i.e., market conditions, cost and performance of new resource technologies, etc.). Near-term fluctuations in the resource plan do not always support the longer-term development needs of transmission infrastructure, or the ability to invest in transmission assets in time to meet customer needs. Together, however, the IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers.

While the core tenets for Energy Gateway's design have not changed, the project configuration and timing continue to be reviewed and modified to coincide with the latest mandatory transmission system reliability standards and performance requirements, annual system reliability assessments, input from several years of federal and state permitting processes, and changes in generation resource planning and our customers' forecasted demand for energy.

As originally announced in May 2007, Energy Gateway consisted of a combination of single- and double-circuit 230-kV, 345-kV and 500-kV lines connecting Wyoming, Idaho, Utah, Oregon and Nevada. In response to regulatory and industry input regarding potential regional benefits of "upsizing" the project capacity (for example, maximized use of energy corridors, reduced environmental impacts and improved economies of scale), PacifiCorp included in its original plan the potential for doubling the project's capacity to accommodate third-party and equity partnership interests. During late 2007 and early 2008, PacifiCorp received in excess of 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint, which supported the upsized configuration. PacifiCorp identified the costs required for this upsized system and offered transmission service contracts to queue customers. These queue customers, however, were unable to commit due to the upfront costs and lack of firm contracts with end-use customers to take delivery of future generation and withdrew their requests. In parallel, PacifiCorp pursued several potential partnerships with other transmission developers and entities with transmission proposals in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading PacifiCorp to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers.

In 2010, PacifiCorp entered into memorandums of understanding to explore potential joint-development opportunities with Idaho Power Company on its Boardman-to-Hemingway project and with Portland General Electric Company (PGE) on its Cascade Crossing project. One of the key purposes of Energy Gateway is to better integrate PacifiCorp's east and west balancing authority areas, and Gateway Segment H from western Idaho into southern Oregon was originally proposed to satisfy this need. However, recognizing the potential mutual benefits and value for customers of jointly developing transmission, PacifiCorp has pursued these potential partnership opportunities as a potential lower-cost alternative.

In 2011, PacifiCorp announced the indefinite postponement of the Gateway South 500-kV segment between the Mona substation in central Utah and Crystal substation in Nevada. This extension of Gateway South, like the double-circuit configuration discussed above, was a component of the upsized system to address regional needs if supported by queue customers or partnerships. However, despite significant third-party interest in the Gateway South segment to Nevada, there was a lack of financial commitment needed to support the upsized configuration.

In 2012, PacifiCorp determined that one new 230-kV line between the Windstar and Aeolus substations and a rebuild of the existing 230-kV line were feasible, and that the second new proposed 230-kV line and proposed 500-kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from PacifiCorp's ongoing focus on meeting customer needs, taking stakeholder feedback and land-use limitations into consideration, and finding the best balance between cost and risk for customers. In January 2012, PacifiCorp signed the Boardman to Hemingway Permitting Agreement with Idaho Power Company and BPA that provides for the PacifiCorp's participation through the permitting phase of the project. The Boardman-to-Hemingway project was pursued as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). Idaho Power leads the permitting efforts on the Boardman-to-Hemingway project, and PacifiCorp continues to support these activities under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement. The proposed line provides additional connectivity between PacifiCorp's west and east balancing authority areas and supports the full projected line rating for the Gateway projects at full build out. PacifiCorp plans to continue to support the project under the Permit Funding Agreement and will assess next steps post-permitting based on customer need and possible benefits.

In January 2013, PacifiCorp began discussions with PGE regarding changes to its Cascade Crossing transmission project and potential opportunities for joint development or firm capacity rights on PacifiCorp's Oregon system. PacifiCorp further notes that it had a memorandum of understanding with PGE for the development of Cascade Crossing that was terminated by its own terms. PacifiCorp had continued to evaluate potential partnership opportunities with PGE once it announced its intention to pursue Cascade Crossing with BPA. However, because PGE decided to end discussions with BPA and instead pursue other options, PacifiCorp is not actively pursuing this opportunity. PacifiCorp continues to look to partner with third parties on transmission development as opportunities arise.

In May 2013, PacifiCorp completed and placed in service the Mona-to-Oquirrh project. In November 2013, the BLM issued a partial ROD providing a right-of-way grant for all of Segment D and most of Segment E of Energy Gateway. The agency chose to defer its decision on the western-most portion of Segment E of the project located in Idaho in order to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In May 2015, the Sigurd-to-Red Butte project was completed and placed in service.

In December 2016, the BLM issued its ROD and right-of-way grant for the Gateway South project.

In January 2017, the BLM issued its ROD and right-of-way grant, previously deferred as part of the November 2013 partial ROD, for the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In October 2020, Segment D2 of Gateway West, from Aeolus to Jim Bridger was placed into service which included a new 500 kV substation at Aeolus, and a new 345kV substation at Anticline.

In October 2020, a portion of Gateway West Segment D1, the 230 kV line between Aeolus and Shirley Basin was also constructed and completed in 2020. The remaining portion of Gateway West, Segment D1, consisting of a new 230 kV line between Shirley Basin and Windstar substations and a rebuild of an existing 230 kV line between Shirley Basin and Dave Johnston substations is under construction with an expected completion date of both lines in December 2024.

Gateway Segment F, referred to as Gateway South, a 416-mile 500kV line from Aeolus substation in Wyoming to Mona/Clover substation in central Utah is under construction with an expected completion date of December 2024.

Other Gateway segments, including Gateway West Segment D3 from Bridger substation in Wyoming to Populus substation in Idaho and Gateway West Segment E from Populus to Hemingway, in Idaho, are in pre-construction activities to address requirements as defined in their permitting Record Of Decision and right of way grants issued by the Bureau of Land Management.

PacifiCorp will continue to adjust the timing and configuration of its proposed transmission investments based on its ongoing assessment of the system's ability to meet customer needs, its compliance with mandatory reliability standards, and the stipulations in its project permits.

Figure 4.3 – Energy Gateway Transmission Expansion Plan

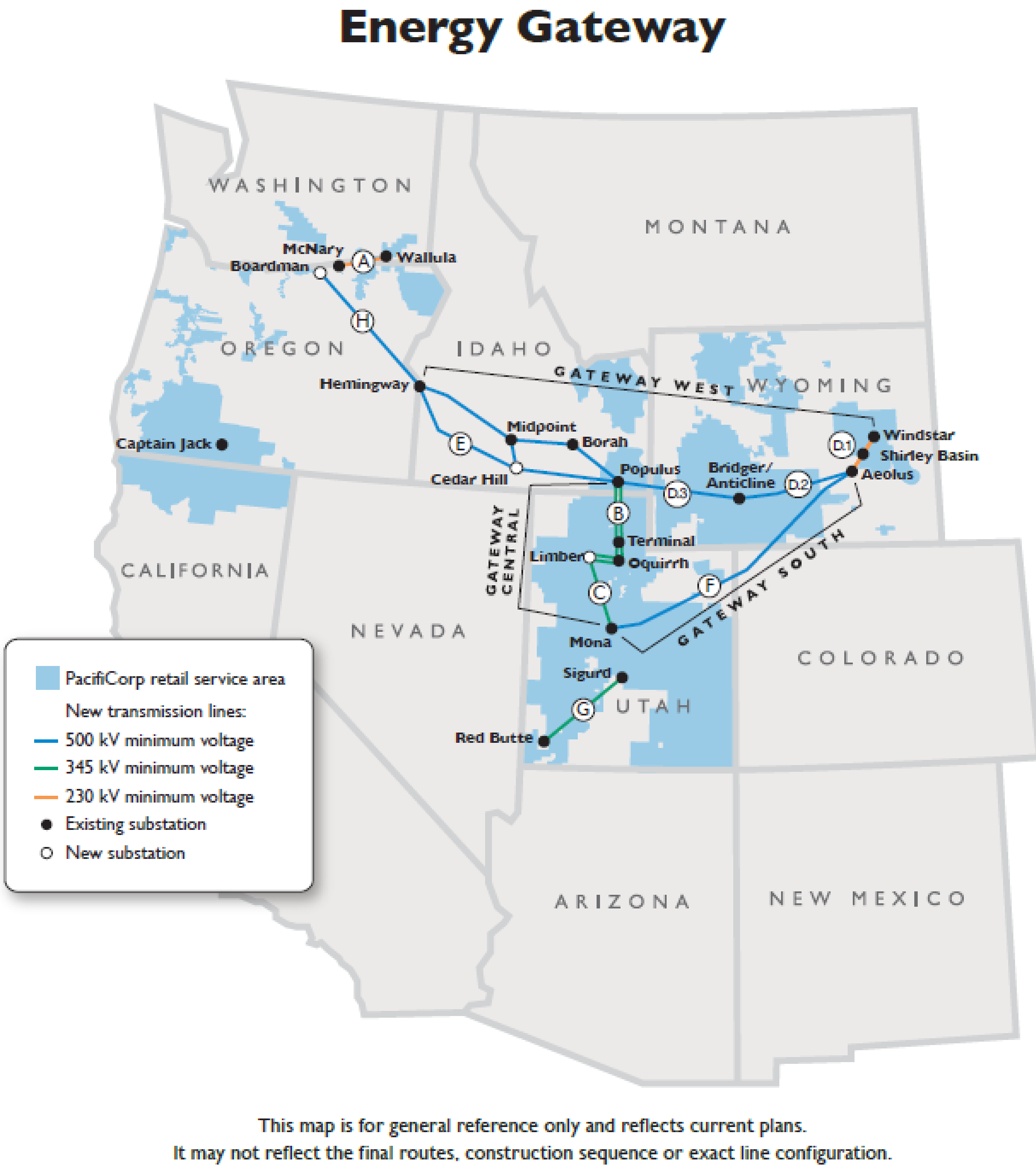


Table 4.1 – Energy Gateway Transmission Expansion Plan

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: completed • Placed in-service: January 2019
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: completed • Placed in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: rights-of-way acquisition underway • Scheduled in-service: 2026
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	59 mi	• Status: permitting underway • Scheduled in-service: December 2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: completed • Placed in-service: November 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in-service: 2028
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2030 earliest
(F) Aeolus-Mona	500 kV single circuit	416 mi	• Status: permitting underway • Scheduled in-service: December 2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: completed • Placed in-service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	290 mi	• Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in-service: 2026

Efforts to Maximize Existing System Capability

In addition to investing in the Energy Gateway transmission projects, PacifiCorp continues to make other system improvements that have helped maximize efficient use of the existing transmission system and defer the need for larger-scale, longer-term infrastructure investment. Despite limited new transmission capacity being added to the system over the last 20 to 30 years, PacifiCorp has maintained system reliability and maximized system efficiency through other smaller-scale, incremental projects.

System-wide, PacifiCorp has instituted more than 130 grid operating procedures and 19 remedial action schemes to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the Energy Imbalance Market since November 2014. As of October 2022, 19 participants have joined the EIM. By broadening the pool of lower-cost resources that can be accessed to balance load system requirements, enhances reliability and reduces costs across the entire EIM Area. In addition, the automated system is able to identify and use available transmission capacity to transfer the dispatched resources, enabling more efficient use of the available transmission system.

To secure further benefits from market-based resource dispatch, PacifiCorp announced in December 2022 that it expects to participate in the Extended Day-Ahead Market (EDAM) being developed by the California Independent System Operator (CAISO).[3] While the EIM makes full use of resource flexibility within the hour and will continue to do so, the EDAM will provide economic, reliability, and environmental benefits by optimizing the pool of resources that are made available to EIM in light of forecasted requirements for the entire market footprint over the following several days, well beyond the end of the current hour. This includes coordination of generator starts and shutdowns and the charging and discharging of energy storage resources.

Transmission System Improvements Placed In-Service Since the 2021 IRP

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area
    - Upgraded the 345-230 #2 transformer at Jim Bridger substation
        - Project driver was to correct NERC Standard TPL-001-4 Category P1 and P3 deficiencies identified in PacifiCorp's 2017 NERC TPL Assessment resulting for a 345-kV or 230-kV bus fault (P1) and for the loss of a generator and both Jim Bridger 345-230 kV transformers #1 and #3 (P3) that will result in thermal overload of existing Jim Bridger 345-230 kV #2 transformer.
        - Benefits include mitigating the risk of thermal overloads and resolution of the NERC TPL-001-4 Category P1 and P3 deficiencies.
2. Goshen Idaho Area
    - Installed a third 345-161 kV transformer at Goshen substation
        - Project driver was to correct NERC Standard TPL-001-4 Category P1 (N-1) deficiency identified in PacifiCorp's 2016 Goshen Area Study resulting in thermal overload of the remaining 345-161 kV transformer at Goshen substation.
        - Benefits include mitigating the risk of thermal overloads and resolution of the NERC Standard TPL-001-4 Category P1 deficiency.
    - Installed a new 161-kV line from Sugarmill to Rigby substations located in Idaho
        - Project driver was to address the single contingency (N-1) and multiple contingency (N-1-1) issues present in the Sugarmill-Rigby area and the large amount of load shedding risk identified in the 2016 Goshen Area Planning Study that proposed adding a new 161-kV line from Goshen to Sugarmill (completed) and then from Sugarmill to Rigby substation (still to complete) to allow a looped configuration during heavy summer load conditions.
        - Benefits include mitigating the risk of thermal overloads and voltage issues and eliminating the loss of up to 150 MW of load for N-1 outages and up to 300 MW for N-1-1 outages.
3. Utah & Idaho – Upgrade Program – Backup Bus Differential Relays
    - Installed backup bus differential relays at various substations located in Utah and Idaho
        - Project driver was to correct the NERC Standard TPL-001-4 Category P5-5 deficiencies identified in PacifiCorp's 2015 NERC TPL Assessments resulting in multiple contingencies for faults plus bus differential relays failure to operate

[3] http://www.caiso.com/Documents/EDAM-Fact-Sheet.pdf

that cause delayed fault clearing due to the failure of a non-redundant relay installation.

   - Benefits include mitigating the risk of delayed clearing of all transmission line connected to specific buses that would lead to thermal overloads and voltage issues, ensuring that critical differential bus protection has the required relay redundancy, improving reliability to the impacted substations and their connected transmission lines, and resolution of the NERC TPL-001-4 Category P5-5 deficiencies.

4. Utah, Idaho & Wyoming - Upgrade Program – Replace Over-dutied Circuit Breakers
   - Replaced breakers identified as over-dutied with higher-capability breakers in various substations located in Idaho, Utah, and Wyoming
     - Project driver was to correct NERC Standard TPL-001-4 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of 13 over-dutied breakers.
     - Benefits include eliminating the risk of over-dutied breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-4 Requirement R2.3 deficiencies.
5. Goshen Idaho Area
   - Rebuilt and converted an existing 69-kV line to 161-kV to establish a new 161-kV source at Rexburg substation in Idaho
     - Project driver was to improve 69-kV capacity and voltage regulation served from Rigby substation by converting an existing 69-kV line to 161 kV to create a 161-kV source at Rexburg substation through a new 161-69 kV transformer installation. The project also will include a new six breaker 69-kV ring bus at Rexburg substation that includes terminating two existing 69-kV lines and one new 69-kV line.
     - Benefits include establishing a new 161-kV source in the area, providing additional 69-kV capacity, improving 69-kV voltage regulation and reliability to customers served from the 69-kV system.
6. Park City Utah Area
   - Installed a 9-mile, 138-kV transmission line between Midway and Jordanelle substations in Utah
     - Project drivers were projected load growth and reliability improvements which required of extension of the 138-kV line from Jordanelle-to-Midway substation.
     - Benefits are the established new 138-kV loop, additional capacity to address projected load growth and improved transmission reliability.

PacifiCorp West (PACW) Control Area

1. Albany/Corvallis Oregon Area
   - Replaced conductor on the 115-kV line between Hazelwood substation and BPA's Albany substation and constructed a new 115-kV ring bus at Hazelwood substation.
     - Project driver was to correct NERC Standard TPL-001-4 Category P6 deficiencies for an outage on the transformers at Fry substation and reduce load loss exposure from various other N-1-1 contingencies.

    - Benefits include mitigating the risk of thermal overloads and voltage issues, improving transmission reliability, reducing the complexity of operating procedures for remaining N-1-1 contingencies and resolution of a number of NERC TPL-001-4 Category P6 deficiencies.

2. Medford Oregon Area
    - Expanded the RAS at Meridian substation
        - Project driver was to expand the existing RAS to cover three additional N-1-1 contingencies on the southern Oregon 500-kV system and trip additional load as identified in the 2015 Meridian Area Load Tripping Assessment and the 2017 NERC TPL Assessment.
        - Benefit of expanding the RAS will be to avoid relying on the Southern Oregon Under-Voltage Load Shedding scheme as the primary mitigation for double contingencies on the 500-kV system.
3. Yakima Washington Area
    - Constructed a new 115-kV transmission line from Outlook substation to Punkin Center substation
        - Project driver was to correct NERC Standard TPL-001-4 Category P1 deficiencies identified in the 2016 NERC TPL Assessment for single contingency (N-1) outages on the 230-kV system serving the Yakima Upper Valley.
        - Benefits include mitigating the risk of thermal overloads, resolving an existing capacity limitation on the 115-kV line, improving transfer capability between the Upper Valley and the Lower Valley system, and resolution of the NERC TPL-001-4 Category P1 deficiency.
4. Oregon – Upgrade Program – Replace Over-dutied Circuit Breakers
    - Replaced breakers identified as over-dutied with higher-capability breakers at Lone Pine Substation
        - Project driver was to correct NERC Standard TPL-001-4 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of three over-dutied 115-kV breakers.
        - Benefits include eliminating the risk of over-dutied 115-kV breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-4 Requirement R2.3 deficiencies.

Planned Transmission System Improvements

PacifiCorp East (PACE) Control Area

1. Central Utah Area
    - Upgrade the 345-138 kV 167 MVA transformer at Camp Williams substation to a 345-138 kV 700 MVA transformer

  - Project driver is to correct NERC Standard TPL-001-4 Category P6 deficiencies during peak summer loading conditions for the N-1-1 event of losing both Spanish Fork substation 345-138 kV transformers that would cause thermal overloads to the Camp Williams 345-138 kV transformer and the Clover – Nebo 138 kV line.
  - Benefits include mitigating the NERC Standard TPL-001-4 Category P6 deficiencies. Provides additional 345 kV source to northern Utah Valley and Jordan Valley as well as increase system reliability

2. Salt Lake City, Utah Area
   - Install two capacitor banks at Magna Substation and rebuild the Tooele – Pine Canyon 138 kV transmission line
     - Project driver is to correct N-1 contingency overload and low voltage issues at Magna substation and on the Tooele – Pine Canyon 138 kV line from consistent load growth and new block loads.
     - Benefits include mitigating the risk of thermal overloads and low voltage issues, adding additional capacity to address projected load growth and improve transmission reliability
   - Loop the 90th South – Terminal 345 kV line into and out of the Midvalley 345 kV yard
     - Project Driver is to eliminate identified overloading of the 90th South – Midvalley 345 kV #1 line under heavy transfer conditions across the Wasatch Front South boundary.
     - Benefits include increasing the transfer capability across the Wasatch Front South boundary by 45 MW, improving operating flexibility, and allowing additional transfers from Clover/Mona as well as from southern Utah to the Wasatch Front.
3. Northern Utah/Southeast Idaho Area
   - Construct a new 345 kV yard adjacent to the existing Bridgerland 138 kV substation. Loop in the existing Populus – Terminal 345 kV line into Bridgeland and Ben Lomond substations.
     - Project driver is to resolve System Operating Limit on Path C.
     - Benefits include the ability to maintain the WECC Path C rating to 1600 MW southbound and 1250 MW northbound.
4. Southeast Idaho Area
   - Install a 25 MVAR shunt capacitor bank at the Franklin 138 kV substation.
     - Project driver is to correct NERC Standard TPL-001-4 Category P1 (N-1) contingency events for the loss of the Treasureton – Franklin 138 kV line.
     - Benefits include resolving the NERC Standard TPL-001-4 Category P1 voltage issues
5. Douglas Wyoming Area
   - Construct a new 115 kV line from Jackalope to Bixby substations.

   - Project driver is to provide a new internal source to Jackalope substation as Western Area Power Administration 115 kV existing radial source cannot accommodate additional load growth in the area.
   - Benefits include offloading PacifiCorp's burden on Western Area Power Administration's lines caused by the Wagonhound 115 kV system at significant cost savings annually.

PacifiCorp West (PACW) Control Area

1. Eastern Oregon Area
   - Replace the entire Burns 500 kV reactive station, including the series capacitor bank, bypass breakers, shunt reactors, and all switches and circuit switchers.
     - Project driver is to replace obsolete and degrading assets to prevent equipment failure which would result in a substantial financial impact and limiting Jim Bridger and Wyoming wind generation for an extended time.
     - Benefits include replacement of obsolete equipment with modern SCADA-operable equipment (reducing operational labor), reduces the risk of failure, and improves recovery time.
2. Portland Oregon Area
   - Reconfigure and convert the existing Bonneville Power Administration's (BPA) St. Johns – Columbia and PacifiCorp's (PAC) Columbia – Knott 57 kV lines, and a portion of the idle 69 kV line north of Albina to 115 kV
     - Project driver is to correct NERC Standard TPL-001-4 Category P6 (N-1-1) deficiencies for load loss of up to 62 MW in the urban northeast Portland core area and Category P6 (N-1-1) deficiencies for voltage issues on the 57 kV system.
     - Benefits include resolution of NERC Standard TPL-001-4 Category P6 (N-1-1) deficiencies, elimination of the 57 kV system voltage in the North Portland and creates a third 115 kV path between the St. Johns/Rivergate and the Knott/Albina area.
3. Roseburg Oregon Area
   - Convert the 69 kV transmission Lines 30 and 65 to 115 kV, along with four distribution substations and constructs a new 115 kV tie from Roberts Creek to the converted Green substation.
     - Project driver is to resolve multiple capacity limitations in the area; notably the Roberts Creek 115-69 kV transformer, the Winchester 115-69 kV transformer, Line 66 between Dixonville and Sutherlin and Line 65 between Dixonville and Southgate. 12 system problems were identified as being affected by these limitations.
     - Benefits include improvement of operability of the system to increase reliability during outages and maintenance and gives the system enough excess capacity to accommodate 20 years of growth at a 1.3% per year rate.
   - Replace the existing 230-115 kV transformer at Dixonville substation with a new 280 MVA transformer.

    - Project driver is to resolve excess voltage on the 115 kV bus. The current transformer steady state voltage sits at 10.4% above nominal in the North Umpqua Hydroelectric System and is nearly 8.7% above nominal at Dixonville substation.
    - Benefit includes bringing the 115 kV bus voltage at Dixonville to operate within an acceptable range and avoids excessive voltage throughout the Roseburg and North Umpqua areas extending the life of the transformers as well as all the downstream equipment.

4. Klamath Falls Oregon Area
    - Construct a second 230 kV transmission line from Snow Goose to Klamath Falls substation.
        - Project driver is to resolve NERC Standard TPL-001-4 Category P6 (N-1-1) for a double contingencies on the 230 kV system serving Yreka, Klamath Falls and La Pine area for the loss of the Klamath Falls-Snow Goose 230 kV line and either the Lone Pine-Copco 230 kV line or Bonneville Power Administration's (BPA) Pilot Butte-La Pine 230 kV line can cause a voltage collapse affecting a large region of the southern Oregon and northern California system.
        - Benefits include Reinforces 230 kV system between in Klamath Falls area to cover TPL-001-4 category P6 (N-1-1) contingencies during all operating conditions on the existing system and minimize risk of a large-scale outage to customers throughout the Klamath Falls and Yreka areas.

5. Medford Oregon Area
    - Construct a 230 kV transmission line between Lone Pine and Whetstone substations
        - Project driver is to correct NERC Standard TPL-001-4 Category P1 (N-1) and P6 (N-1-1) outage combinations including loss of the two Meridian-Lone Pine 230 kV lines (N-1), N-1-1 loss of the Meridian-Whetstone and Dixonville-Grants Pass 230 kV lines, or N-1-1 loss of Sams Valley 500-230 kV source and either the Meridian-Whetstone 230 kV line or Dixonville-Grants Pass 230 kV line.
        - Benefits include resolving the NERC Standard TPL-001-4 Category P1 and P6 issues as well as prevents reverse flow across the Medford 115 kV system to support the 230 kV system and allows operating the Medford 115 kV system radial.
    - Construct one new 500-230 kV substation called Sams Valley
        - Project driver is to correct NERC Standard TPL-002-4 deficiencies for the loss of a single 230-kV line and for N-1-1 and N-2 outages to 230-kV lines that were initially identified in PacifiCorp's 2010 NERC TPL Assessment and supported through subsequent NERC TPL Assessments, and to provide a second 500-kV source to address load growth in the Southern Oregon region.
        - Benefits include adding a second source of 500-kV capacity, adding a new 230-kV line, improving reliability of the 230-kV network, mitigates the risk of thermal overloads and low voltage, mitigates the risk of shedding load in preparation of the second contingency for N-1-1 outages, and resolves the NERC TPL-001-4 deficiencies.

These investments help maximize the existing system's capability, improve PacifiCorp's ability to serve growing customer loads, improve reliability, increase transfer capacity across WECC Paths, reduce the risk of voltage collapse and maintain compliance with North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability standards.

CHAPTER 5 – RELIABILITY AND RESILIENCY

CHAPTER HIGHLIGHTS

- Regional resource adequacy assessments highlight that there are resource adequacy risks through the mid-2020s. In conditions of increased demand and resource variability, higher summer temperatures reduce excess energy supply, in turn tightening supply from the market.
- PacifiCorp's wildfire mitigation plans, which outline a risk-based, balanced, and integrated approach, contain six critical focus areas of planning and execution for a reliable and resilient energy future: (1) Risk analysis and drivers, (2) Situational awareness, (3) Inspection and correction, (4) Vegetation management, (5) System hardening, and (6) Operational practices.
- The 2023 IRP preferred portfolio includes the Energy Gateway South (GWS), Energy Gateway West segments D.1, D3 and D2.2, and Boardman-to-Hemingway (B2H) transmission lines. The preferred portfolio also includes other transmission upgrades that support the transition to renewable energy by providing access to low-cost, location-specific renewable resources, and additional transfer capability, which enables greater use of other low-cost resource options and relieves stress on current assets.

Introduction

Serving reliably (i.e., keeping the lights on for customers), as well as planning for a resilient system (i.e., operating through and recovering from a major disruption) is a primary focus for PacifiCorp. With the increasing retirement of thermal baseload resources, the incorporation of increasing numbers of intermittent renewable resources, and the impacts of climate change, planning for a reliable and resilient energy future is more crucial, and more complex, than ever. PacifiCorp continues to build on a strong track record of serving its customers safely, reliably, and affordably.

The focus on reliability and resiliency spans across several areas of the company: PacifiCorp's resource planning and energy supply teams work closely with regional partners and ensure that there is sufficient supply to serve customers, while transmission and distribution teams work to mitigate the destructive impact of wildfire risk throughout the west to ensure that PacifiCorp can deliver power safely to customers now and in the future.

Supply-Based Reliability

Regional Resource Adequacy

As part of its 2023 IRP, PacifiCorp has conducted a review and evaluation of western resource adequacy studies and information, including evaluating the Western Electricity Coordinating Council (WECC) Power Supply Assessment (PSA) to glean trends and conclusions from the supporting analysis.

In 2020, WECC published and adopted the WECC Reliability Risk Priorities (WRRP), which outlined four priorities that were deemed to be the most significant to reliability in the western interconnection. Resource adequacy was identified as one of the four priorities, and in December 2020 WECC published the Western Assessment of Resource Adequacy (WARA), which will become an annual report in the future. PacifiCorp has reviewed the WARA, which serves as an interconnection-wide assessment of resource adequacy and uses that assessment as the basis of the following discussion. PacifiCorp also reviewed the 2020 North American Electric Reliability Council (NERC) Long-Term Reliability Assessment and the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

WECC Western Assessment of Resource Adequacy Report

The WECC Western Assessment of Resource Adequacy was published in November 2022and was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years. The analysis is probabilistic and represents an hourly assessment of resource adequacy over the study period. The region-wide projections included in the study were categorized into two scenarios: one in which the region is required to meet its own demand and associated load risk considerations, and a second scenario in which resource adequacy is defined by the reserve margin that entities must hold to account for variability on the system and meet a one-day-in-ten-year reliability threshold.

- Scenario 1. All Planned Resources with Imports: This scenario reflects the expected resource additions and imports in current resource plans; Scenario 2: No New Resources with Imports: This scenario highlights the challenges facing the West if new resources are not built; and
- Scenario 3: All Planned Resources without Imports: This scenario evaluates the role of imports in ensuring resource adequacy. To inform the study, WECC has developed peaking assumptions and ramp need estimates on both an interconnection-wide basis, as well as for each planning subregion within the WECC. A summary of the planning regions and peak assumptions is shown in Table 5.1.

Table 5.1 – Planning Subregions and Peaking Assumptions underlying analysis

Designation	Subregion	Peaking Assumption	Ramp[1]	Peak Load
NWPP-NW[2]	Northwest Power Pool - Northwest	March	13.4%	4,500MW
NWPP-NE[3]	Northwest Power Pool – Northeast	January	13.5%	800MW
NWPP-C[4]	Northwest Power Pool – Central	June	13.4%	2,300MW
CAMX[5]	California and Mexico	August	19.5%	1,300
DSW[6]	Desert Southwest	May	13%	800MW

Interconnection-wide peak hour demand occurs in the summer. Based on data submitted by BAs, the peak demand for the Western interconnection is expected to grow from 175 GW in 2023 to 194 GW in 2032, an increase of almost 11%. For the interconnection and the California and Mexico (CAMX), Northwest Power Pool—Central (NWPP-Central), and Desert-Southwest (DSW) subregions, 2022 plans show a slightly higher peak demand than the 2021 plans. However, 2022 plans for the Northwest Power Pool—Northeast (NWPP-NE) and Northwest Power Pool—Northwest (NWPP-NW) subregions generally show a lower peak demand number

[1] Represents needed resource ramp from lowest to highest demand hour of the peak demand day
[2] NWPP-NW covers Washington, Oregon, British Columbia, and portions of Montana and Idaho
[3] NWPP-NE covers portions of Idaho, Montana, Wyoming, South Dakota, Nebraska, and Alberta
[4] NWPP-C covers Nevada, Utah, Colorado, and portions of California, Idaho, and Wyoming
[5] CAMX covers the majority of California and Baja California
[6] DSW covers Arizona, New Mexico, and portions of Texas and California

than the 2021 plans. Overall, the peak hours for the northern regions are consistent with last year's Western Assessment.

WPP-NW

- For the NWPP-NW subregion the risk has spread into the late spring and summer months. This is due in part to the inclusion of data from the June 2021 Pacific Northwest heat wave in the 2022 assessment, increased the variability in the demand forecast for the subregion. So, while demand forecasts for the subregion decreased, variability increased, creating a need for additional reserves, which increases the PRMI. As the NWPP-NW evolves from a dual-peaking subregion to a summer-peaking subregion, the risk will continue to spread throughout the year.

NWPP-NE

- For the NWPP-NE subregion, the demand-at-risk hours were confined to December and January in the 2021 assessment, attributable to the variability in temperature during those months and the effects of heating requirements. This year's results show that the risk has spread into February and March. This can be attributed to the changing resource mix. With the continued addition of wind resources and the retirement of coal resources, resource variability is expected to grow.
- This year's results for the NWPP-Central subregion show a slight increase in both the number of demand-at-risk hours and the number of megawatts at risk (magnitude) compared to the 2021 assessment. As this subregion continues to add VERs and retire dispatchable resources, these numbers are expected to grow. The NWPP-Central subregion has the widest demand-at-risk spread, which covers almost the entire year. This is because its footprint straddles the northern (typically winter peaking) and southern (summer peaking) parts of the interconnection.

Resource Assumptions

The WECC Western Assessment of Resource Adequacy makes the following three recommendations. Details on how PacifiCorp has incorporated or is considering each recommendation are also provided.

> **Recommendation 1:** *Resource plans should include contingency plans to manage the risk of impediments to building planned resources. State commissions and regulatory bodies should continue to scrutinize integrated resource plans to ensure that utilities are planning for the increased risks. Likewise, commissions must be prepared to consider recovery of costs incurred by the utilities as they plan for increased risks.*
>
> - PacifiCorp's transmission system provides access to diverse resource opportunities, which limits its reliance on particular locations, and allows it to flexibly respond to evolving opportunities.

- Within the action plan window, PacifiCorp's modeling only allows selection of generating resources with completed interconnection studies that support assumed online dates.
- Over the rest of the IRP horizon, resource selections may be dependent on transmission upgrades or, in the case of nuclear or non-emitting peaking resources, significant technological progress. PacifiCorp recognizes the uncertainty in these options and evaluates scenarios that exclude certain major transmission upgrades and technologies to assess possible alternatives.
-

Recommendation 2: *The Western Interconnection should evaluate resource and transmission adequacy in a coordinated fashion through comprehensive wide-area system planning.*

- PacifiCorp supports increased coordination of resource and transmission adequacy and believes its participation in the WRAP and EDAM will further these goals.
-

Recommendation 3: *Some entities must evaluate and adapt their resource planning approaches to account for increasing uncertainty.*

- PacifiCorp recognizes that resource planning is changing dramatically as reliance on variable energy resources and duration-limited storage increases. When combined with retirements of dispatchable thermal resources the periods at risk of reliability shortfalls can change dramatically. Because increasing renewables and retiring dispatchable resources are major elements of PacifiCorp's portfolio analysis, the system impact of these changes are already an inherent part of its analysis, though opportunities for further analysis abound.

NERC Long-Term Reliability Assessment (LTRA)

Resources

As part of the regional reliability assessment to support the 2023 IRP, PacifiCorp reviewed and incorporated learnings from the NERC LTRA, published in December 2022. The NERC LTRA organizes resources into three broad capacity supply categories in its 10-year WECC region reliability assessment:

<u>Tier 1: Anticipated Resources</u>

- Existing generating capacity able to serve peak hour load with firm transmission
- Capacity that is either under construction or has received approved planning requirements
- Firm net capacity transfers (imports minus exports) reliant on firm contracts
- Less confirmed retirements, for generators that have announced retirement plans

Tier 2: Prospective Resources

- Existing capacity that may be available to serve peak hour load, but lacks certainty associated with firm transmission, peak availability, etc.
- Capacity additions that have been requested but not received approval
- Non-firm net capacity transfers and transfers without firm contracts, but assessed to have a high probability of future implementation
- Less unconfirmed retirements of capacity that is expected to retire based upon survey or analysis.

Tier 3:

- Speculative resources, defined as planned capacity, but that do not meet requirements for Tier 1 or Tier 2

Planning Reserve Margin

The LTRA defines "planning reserve margin" as the difference between resources and demand, divided by demand, expressed as a percentile.

Resources in this calculation are reduced by expected operating limits due to fuel availability, transmission and environmental limitations. Comparing the *anticipated* resource-based reserve margin to the reference planning margin yields one of three risk determinations:

- Adequate: Reasonable expectation of meeting all forecast parameters; anticipated reserve margin exceeds the reference margin level
- Marginal: Low expectation of meeting all forecast parameters; anticipated reserve margin is short of the reference margin level, but the planning reserve margin is higher than the reference margin level
- Inadequate: Load interruption is likely; both the Anticipated reserve margin and the planning reserve margin are less than the reference margin level and Tier 3 resources are unlikely to advance

WECC Subregions

Table 5.2 presents the WECC subregions used for the NERC LTRA. In the data that follows, the two subregions in Canada are not considered.

Table 5.2 – WECC Subregion Descriptions

Designation	Subregion	Country	Peaking Assumption
WPP	Western Power Pool	United States	Summer
SRSG	Southwest Reserve Sharing Group	United States	Summer
CAMX	California to Mexico	United States	Summer
AB	Alberta	Canada	Winter
BC	British Columbia	Canada	Winter

LTRA WECC Assessment

Table 5.3 through Table 5.5 represent the three types of reserve margins relevant to the WECC planning reserve margin calculation. In each table, the figures do not include WECC subregions outside of the United States.

Table 5.3 – NERC LTRA Anticipated Reserve Margin

Anticipated Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
WPP	Summer	22.70%	23.40%	19.70%	16.00%	15.50%	14.80%	12.10%	10.60%	7.60%	4.50%
SRSG	Summer	29.70%	32.80%	30.70%	29.50%	27.00%	26.10%	25.90%	26.30%	24.00%	20.00%
CAMX	Summer	38.50%	27.40%	26.30%	22.50%	20.40%	19.30%	16.10%	14.40%	11.70%	10.70%

Table 5.4 – NERC LTRA Prospective Reserve Margin

Anticipated Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
WPP	Summer	24.90%	25.70%	21.80%	17.90%	17.60%	16.90%	14.50%	13.40%	10.10%	7.10%
SRSG	Summer	32.20%	35.80%	33.80%	32.60%	29.90%	29.00%	28.80%	29.10%	26.80%	22.80%
CAMX	Summer	39.60%	28.50%	26.90%	23.10%	20.20%	19.10%	15.90%	14.20%	11.50%	10.50%

Table 5.5 – NERC LTRA Reference Reserve Margin

Reference Planning Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
WPP	Summer	12.50%	12.90%	13.80%	13.70%	13.50%	14.00%	12.30%	12.40%	13.10%	12.90%
SRSG	Summer	13.10%	13.30%	12.20%	12.10%	11.90%	11.90%	12.60%	12.30%	11.50%	11.20%
CAMX	Summer	19.20%	17.70%	19.10%	18.90%	18.70%	17.90%	18.00%	16.90%	18.20%	18.10%

Using this data, a reserve margin position can be calculated to show projected shortfalls, both with and without the inclusion of prospective resource additions. Table 5.6 reports the reserve margin differential based on anticipated resources, whereas Table 5.7 reports the reserve margin differential assuming prospective resources are achieved during the study period. In either table, a positive percentage represents a margin of overage where WECC is expected to have resources above the reference margin target; a negative number (highlighted for emphasis) represents a year where a given subregion is at risk of falling below the reference margin.

Based on this evaluation, potential shortfalls in planning reserve margin show up in the back four years of the study period in the WPP and CAMX subregions of WECC.

Table 5.6 – Planning Reserve Margin Shortfalls by Subregion with Anticipated Resources

Shortfalls Assuming Anticipated Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
WPP	Summer	10.20%	10.50%	5.90%	2.30%	2.00%	0.80%	-0.20%	-1.80%	-5.50%	-8.40%
SRSG	Summer	16.60%	19.50%	18.50%	17.40%	15.10%	14.20%	13.30%	14.00%	12.50%	8.80%
CAMX	Summer	19.30%	9.70%	7.20%	3.60%	1.70%	1.40%	-1.90%	-2.50%	-6.50%	-7.40%

Table 5.7 – Planning Reserve Margin Shortfalls by Subregion with Prospective Resources

Shortfalls Assuming Prospective Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
WPP	Summer	12.40%	12.80%	8.00%	4.20%	4.10%	2.90%	2.20%	1.00%	-3.00%	-5.80%
SRSG	Summer	19.10%	22.50%	21.60%	20.50%	18.00%	17.10%	16.20%	16.80%	15.30%	11.60%
CAMX	Summer	20.40%	10.80%	7.80%	4.20%	1.50%	1.20%	-2.10%	-2.70%	-6.70%	-7.60%

Prior Measures

PacifiCorp's past assessments, relying on calculations incorporated into the WECC PSA, have reported a rolling succession of power supply margins, where each year there is a downward trend in reserve margins extending into the future. The rolling nature of each year's outcome tells us that while declining reserve margins are important, the trend line is rarely followed from one year to the next. Rather, the trend line tends to be pushed forward like a wave, where the future shortage is not allowed to materialize because of cumulative actions taken within the WECC in recognition of future need.

Pacific Northwest Resource Adequacy Forum's Adequacy Assessment

As in the 2019 IRP, the Pacific Northwest Resource Adequacy Forum (later replaced by the Resource Adequacy Advisory Committee) issued resource adequacy standards in April 2008, which were subsequently adopted by the Northwest Power and Conservation Council. The standard calls for assessments three and five years out, conducted every year, and including only existing resources and planned resources that are already sited and licensed. As reported in the latest Pacific Northwest Power Supply Adequacy Assessment for 2027, the Council studied loss of load probability (LOLP) along with incremental adequacy measures. Additional metrics included:

- Loss of load events, or LOLEV, limiting the frequency of shortfalls to prevent excessive use of emergency measures
- Duration Value at Risk, limiting shortfall duration for 1 in 40-year events
- Peak and Energy Value at Risk, limiting shortfall magnitude for 1 in 40-year events

Based on updated results for adequacy in year 2027, the Assessment concluded that power supply would be adequate but with major outstanding risks that would undermine this conclusion. These risks are identified as:

- Significantly limited future energy market supply
- New policies driving electrification
- Early retirements of major resources without replacement

2021 Northwest Power Plan

The Northwest Power and Conservation Council finalized the 2021 Northwest Power Plan in March 2022. Leading to its publication, PacifiCorp was actively participated in the planning process, and noted that the findings of the Northwest Power Plan are similar to what the Company has observed through the WECC Western Assessment of Resource Adequacy and the NERC LTRA, primarily:

- By 2027 the 2021 Power Plan strategy highlights the need to increase reserves and also acquire up to 1,000 MW of energy efficiency, 720 MW of demand response, and at least 3,500 MW of new renewable resources;
- By 2030, there is a resource adequacy need in the next few years, with up to 1,400 MW of nameplate capacity of new natural gas fired generation;
- After 2023, even with additional coal-fired generation retirements, adequacy can be maintained through a high level of expected renewable resource buildout and the optimization of the existing hydro and gas-fired resource fleet; and
- There is inherent uncertainty driven by the possibility of accelerated loads due to electrification programs and the uncertainty of WECC-wide resource buildout.

NWPP Resource Adequacy Program

Beginning in early 2019, PacifiCorp along with other Northwest Power Pool (NWPP) member entities and the Northwest Power Pool itself engaged in the development of a regional Resource Adequacy (RA) Program as a mechanism to assure a high likelihood of adequate supply to meet customer demand under a wide array of scenarios.[7] This program includes two components, a forward showing (FS) planning mechanism and an operational program (Ops Program) to help participants that are experiencing extreme events meet customer demand. The program is intended to be a starting point and does not solve every issue facing the region, but is an incremental step toward increased regional coordination, which could better position the region to continue to tackle these big issues.

The program will focus on creating a capacity RA program with a demonstration of deliverability. Additional adequacy programs may also be necessary following the implementation of the capacity program. The region may also benefit from other forms of coordination, and while the structure and process associated with the program may serve as foundational building blocks to additional regional coordination, the NWPP and its participants are only working to implement the capacity RA program at this time. The proposed RA program does not replace or supplant the

[7] https://www.nwpp.org/resources/2021-nwpp-ra-program-detailed-design

resource planning processes used by states or provinces or the regulatory requirements of the Federal Energy Regulatory Commission (FERC), North America Electric Reliability Corporation (NERC) or Western Electricity Coordinating Council (WECC). The program is designed to be supplemental and complementary to those processes and requirements. Program planning is scheduled to continue throughout 2023, with a proposed implementation date in 2025.

Reliable Service through Unpredictable Weather and Challenging Market Liquidity

PacifiCorp, other utilities, and power marketers who own and operate generation engage in market purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp models front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help PacifiCorp cover short positions.

Solicitations for FOTs can be made years, quarters, or months in advance, however, most transactions to balance PacifiCorp's system are made on a balance of month, day-ahead, hour-ahead, or intra-hour basis. Annual transactions can be available three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

In developing FOT limits for the 2023 IRP, PacifiCorp reviewed the studies described in the sections above as part of its assessment of market reliance in addition to consideration of its active participation in wholesale power markets, its view of physical delivery constraints, and market liquidity and market depth. The 2023 IRP FOT limits are 1,000 MW in the winter, and 500 MW in the summer, the same as in the already restricted 2021 IRP. In the short-term, market purchase limits are assumed to be higher, shifting into a narrower market availability assumption beyond the first five years. This long-term shift is based on future market availability concerns represented in the foregoing analysis and as a hedge against the risk of future high market reliance. Another concern addressed by long-term restrictions is the possibility that future requests for proposals may not result in acquiring all resources anticipated by integrated resource planning. Table 5.8 details the assumed market availability limits.

In the 2021 IRP, there was not explicitly differentiated short-term FOT limit, however the model was able to represent potential shortfalls against market availability under the assumption that historical trends supported higher purchases in the first few years. This resulted in higher short-term costs but with an implied unlimited purchase constraint. The 2023 IRP improves on this modeling with explicitly higher short-term constraints which fall within reasonable bounds.

Table 5.8 – Maximum Available Front Office Transactions by Market Hub

Market Hub	Availability Limit (MW)				
	2023 IRP			2021 IRP	
	Short-term (2023-2027)	Long-term (2028-2042) Summer	Long-term (2028-2042) Winter	Summer	Winter
Mid-Columbia (Mid-C)	1979	500	350	500	350
California Oregon Border (COB)	424	0	250	0	250
Nevada Oregon Border (NOB)	200	0	100	0	100
4 Corners (4C)	398	0	0	0	0
Mona	325	0	300	0	300
Total	**3326**	**500**	**1000**	**500**	**1000**

PacifiCorp's historical market purchases at times exceeded its 2021 IRP FOT planning limits, indicating that it was able to find sellers in the market to meet capacity needs. While PacifiCorp expects to continue to use its transmission access to access markets whenever it is economic to do so, planning to rely exclusively on markets and imports at the same levels is becoming riskier as western resource mix evolves and there is greater reliance on variable and short-duration resources.

Aligned with review of the regional studies discussed above, and the historical market purchases and transactions, the company will continue to refine its assessments of market depth and liquidity for transactions to quantify the risk associated with the level of market reliance. Additional description is provided in Volume I, Chapter 7 (Resource Options); also, see the sensitivities discussion in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).

Planning for Load Changes as a Result of Climate Change

Recent weather-based reliability events throughout the United States have underscored the need for utilities to consider the potential for increasingly extreme weather and the underlying reliability challenges that may be caused as part of its planning process. PacifiCorp has accounted for climate change within the 2023 IRP to assess the ways in which climate change may impact planning assumptions (see Appendix A for additional detail regarding how climate change is incorporated into the base forecast). The following section provides an overview on the load assumptions associated with climate change projections.

The Company's load forecast is based on historical actual weather adjusted for expectations and impacts from climate change. The historical weather is defined by the 20-year period of 2002 through 2021. The climate change weather uses the data from the historical period and adjusts the percentile of the data to achieve the expected target average annual temperature and calculate the HDD and CDD impacts and peak producing weather impacts within the energy forecast and peak forecast, respectively.

The climate change weather target temperature relies on actual 1990 average temperatures and projected temperature increases over 1990 average temperatures as determined by the United States Bureau of Reclamation (Reclamation) in the West-Wide Climate Risk Assessments:

Hydroclimate Projections Study (Study).[8] The Company determined daily average temperatures and peak producing temperatures that correspond to the midpoint of the projected temperature increase between the Representative Concentration Pathway (RCP) 4.5 and RCP 8.5 ranges in the Study.

Table 5.9 below provides the projected range of temperature change for select sites within PacifiCorp's service territory, which were used to model projected climate change temperatures in the 2023 IRP.

Table 5.9 – Projected Range of Temperature Change in the 2020s and 2050s relative to the 1990s[9]

Bureau of Reclamation Site	PacifiCorp Jurisdiction Assumption	Projected Range of Temperature Change (°F)*	
		2020s	2050s
Klamath River near Klamath	California	1.7 to 2.6	3.6 to 5.2
Snake River Near Heise	Idaho	1.6 to 3.0	4.1 to 5.9
Klamath River near Seiad Valley	Oregon	1.8 to 2.7	3.7 to 5.3
Green River near Greendale	Utah	1.8 to 3.3	4.2 to 6.3
Yakima River at Parker	Washington	1.8 to 2.8	3.6 to 5.6
Green River near Greendale	Wyoming	1.8 to 3.3	4.2 to 6.3

*Lower bound of temperature projections based on RCP 4.5, while upper bound based on RCP 8.5

As illustrated in Table 5.10, relative to the 20-year normal weather scenario, the 2023 IRP base model with climate change temperatures incorporated results in summer peaks being higher by approximately 30 MW (<1% higher) over the 2023-2027 timeframe. By 2042, summer peaks are projected to be 474 MW (3.1%) higher than the 20-year normal weather scenario.

As illustrated in Table 5.11, increasing winter temperatures results in less heating load, which drive lower winter peaks. By 2042, winter peaks are projected to be 319 MW (2.4%) lower than the 20-year normal weather scenario.

As illustrated in Table 5.12, increasing temperatures are driving a slightly lower energy forecast over the 2023 – 2036 timeframe. This is driven by lower heating loads for Oregon, which is largely offset by increased loads in Utah.

[8] United States Bureau of Reclamation, March 2021, Managing Water in the West, Technical Memorandum No. ENV-2021-001, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2021secure/westwidesecurereport1-2.pdf

[9] United States Bureau of Reclamation, March 2021, Managing Water in the West, Technical Memorandum No. ENV-2021-001, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2021secure/westwidesecurereport1-2.pdf

Table 5.10 – Change in Summer Coincident Peak 2023 Base vs 20-year Normal Scenario (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2023	21	16	(4)	(0)	(9)	6	11
2024	23	17	(4)	(0)	(8)	7	12
2025	16	15	(4)	(0)	(9)	7	8
2026	43	25	(2)	(0)	4	7	9
2027	67	33	(0)	(0)	17	7	11
2028	95	41	1	(0)	31	8	15
2029	120	121	5	4	(2)	(25)	17
2030	146	53	7	0	58	9	18
2031	169	61	9	0	72	10	18
2032	195	69	10	0	86	10	19
2033	220	77	12	1	100	11	22
2034	245	85	12	1	114	11	23
2035	270	93	11	1	129	11	25
2036	288	103	12	1	143	12	17
2037	326	113	13	1	158	13	28
2038	353	124	13	1	172	13	29
2039	381	134	14	2	187	14	31
2040	410	145	14	2	203	14	33
2041	439	155	14	2	218	15	35
2042	474	175	15	2	235	16	30

Table 5.11 – Change in Winter Coincident Peak 2023 Base vs 20-year Normal Scenario (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2023	(103)	(77)	(2)	(3)	(11)	(5)	(5)
2024	(102)	(76)	(2)	(3)	(11)	(6)	(5)
2025	(105)	(77)	(3)	(2)	(12)	(6)	(5)
2026	(114)	(81)	(6)	(3)	(13)	(6)	(5)
2027	(131)	(91)	(10)	(3)	(16)	(6)	(6)
2028	(144)	(99)	(12)	(3)	(18)	(6)	(6)
2029	(157)	(106)	(15)	(3)	(20)	(6)	(6)
2030	(172)	(113)	(19)	(3)	(25)	(6)	(7)
2031	(184)	(123)	(21)	(3)	(24)	(6)	(6)
2032	(197)	(129)	(25)	(3)	(27)	(7)	(8)
2033	(210)	(136)	(28)	(3)	(29)	(7)	(8)
2034	(223)	(143)	(31)	(3)	(31)	(7)	(8)
2035	(234)	(149)	(34)	(3)	(33)	(7)	(8)
2036	(254)	(161)	(37)	(3)	(38)	(7)	(8)
2037	(261)	(167)	(39)	(3)	(37)	(8)	(8)
2038	(269)	(170)	(41)	(3)	(39)	(8)	(8)
2039	(279)	(176)	(43)	(3)	(40)	(8)	(9)
2040	(292)	(183)	(46)	(3)	(42)	(9)	(9)
2041	(307)	(189)	(48)	(3)	(47)	(10)	(9)
2042	(319)	(203)	(49)	(3)	(46)	(10)	(8)

Table 5.12 – Change in Annual Energy 2023 Base vs 20-year Normal Scenario (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2023	(108,906)	(174,343)	(42,645)	(10,620)	106,441	(15,609)	27,868
2024	(108,181)	(175,197)	(42,495)	(10,584)	108,163	(15,817)	27,748
2025	(106,712)	(174,386)	(42,698)	(10,554)	109,005	(15,650)	27,570
2026	(99,146)	(176,169)	(44,112)	(10,796)	118,271	(15,677)	29,337
2027	(91,402)	(177,879)	(45,528)	(11,048)	127,689	(15,725)	31,089
2028	(83,836)	(180,530)	(46,813)	(11,301)	137,843	(15,952)	32,916
2029	(75,015)	(181,143)	(48,383)	(11,557)	147,284	(15,801)	34,585
2030	(66,090)	(182,520)	(49,779)	(11,808)	157,492	(15,815)	36,339
2031	(56,948)	(184,031)	(51,187)	(12,063)	168,033	(15,801)	38,100
2032	(48,063)	(186,778)	(52,498)	(12,325)	179,469	(15,942)	40,012
2033	(37,578)	(187,266)	(54,034)	(12,593)	190,310	(15,646)	41,652
2034	(27,182)	(188,845)	(55,466)	(12,857)	202,040	(15,499)	43,446
2035	(16,183)	(190,353)	(56,898)	(13,120)	214,233	(15,303)	45,258
2036	(2,041)	(190,870)	(57,504)	(13,358)	226,982	(15,661)	48,370
2037	14,226	(188,713)	(58,266)	(13,593)	239,233	(15,558)	51,123
2038	30,142	(187,823)	(58,956)	(13,830)	252,319	(15,643)	54,075
2039	46,518	(186,862)	(59,641)	(14,072)	265,768	(15,711)	57,036
2040	62,375	(187,309)	(60,280)	(14,318)	280,075	(16,004)	60,212
2041	80,437	(184,769)	(60,995)	(14,545)	293,596	(15,832)	62,981
2042	98,038	(183,632)	(61,657)	(14,779)	308,015	(15,878)	65,970

Weather-Related Impacts to Variable Generation

The effect of extreme weather events associated with climate change is an evolving area of research that is growing in importance as renewable, intermittent resources dependent upon wind, solar, and hydrologic conditions comprise an increasing proportion of utility resource portfolios.

Wildfire Impacts

Increased wildfire frequency associated with climate change is expected to have a range of impacts to intermittent generation sources, including wind, solar, and hydro resources.

Wind generation sites in PacifiCorp's system are most likely to be subjected to fast moving range fires. Impacts at wind generation sites from range fires are likely to be limited and short in duration, as turbines and collector substations are surrounded by gravel surfaces that are fire resistant. Sensitive turbine equipment is located far above the ground away from damaging heat sources. Impacts to transmission lines and aboveground collector lines from range fires at wind generation sites is also anticipated to be minor due to the limited fuels available to cause ignition to wooden poles. Outage durations are likely to be short when operations staff is required to evacuate a site in advance of a fire and to curtail generation as a precautionary measure.

Climate change also poses fire risks at solar generation sites, which are also likely to manifest as range fires given solar projects are typically sited well away from substantial tree stands that could block solar panels. Impacts could be significant depending on the amount of vegetation at a site, as generating equipment is close to the ground close to potential fuel sources. If a range fire creates sufficient heat to impact equipment, resumption of generation will be dependent on the ability to obtain and install necessary replacement equipment.

Fire impacts at hydro generation sites will be driven primarily by impacts to transmission lines. Hydro generation sites are typically in heavily forested terrain and serviced by only one or two transmission lines. An intense forest fire can damage miles of transmission lines that can take weeks to months to restore to service. If a fire threatens a hydro generation site, the site will be proactively evacuated with generation units typically taken offline and the facility put into spill to avoid potential instream flow impacts that could occur with an unplanned unit shutdown resulting from impacts to local transmission lines. Generation units would be restarted as soon as possible when conditions permit safe re-entry to provide generation locally until transmission service, if interrupted, is restored. Fire damage to dams, water conveyance structures, and generating plants is expected to be minimal. Some damage to local distribution lines and communication infrastructure upon which hydro generation sources rely is also possible, which could impact generation restoration timelines.

PacifiCorp outlines its wildfire mitigation strategies later in this document.

Extreme Weather Impacts

Climate change also has the potential to result in increased frequency and magnitude of extreme weather events. Such changes can result in more frequent and intense precipitation events and flooding, which could impact hydropower generation and change historic operating practices to maintain flood control capabilities at projects where flood control benefits are part of project operations. Like wildfire events, increased flooding has the potential to impact access to remote hydro facilities. Increased precipitation and reduced snow water equivalent have the potential to modify runoff patterns impacting hydro generation but is not expected to impact dam safety at PacifiCorp hydro facilities, which are subject to FERC dam safety requirements that ensure they are able to safely pass probable maximum flood events. Increases in extreme weather that results in more frequent flood events has the potential to increase debris loading in river systems and reservoirs, potentially increasing generation downtime to remove debris that may reduce inflows to hydro units or reduce flows through fish screens.

Changes to wind patterns and wind speeds, and changes in extreme high and low air temperatures have the potential to impact wind and solar generation. Extreme high temperatures can raise ground temperatures, which has the potential to impact collector system capacities at wind and solar projects and reduce collector system carrying capacity, limiting output, similar to high temperature impacts to high voltage transmission lines. However, these impacts are not anticipated to be significant on wind energy resources given peak output is typically observed outside of summer months. Increasing air temperatures result in lower air densities, which could negatively impact wind energy output even if wind speeds are unchanged. Lower wind speeds in the summer relative to historic experience because of extreme high temperatures is also possible. Wind turbines in PacifiCorp's fleet generally are protected from extreme low temperatures given the conditions in which they currently operate, and low temperature protection features are installed in PacifiCorp turbines where weather conditions warrant their inclusion.

There is limited research on site-specific impacts from extreme weather events and thus how to plan to improve the resiliency of intermittent generation resources. Resiliency will be enhanced as planning to ensure site access occurs in response to observed changes in extreme weather events and as more research is available to locally forecast impacts of climate change and extreme weather so those impacts can be factored into the resource planning process.

Impacts on wind and solar energy

The impact on renewable energy generation due to extreme weather events and climate change is an evolving topic. For conclusive trends of climate change impact, data collection specific to geographic locations is critical. Climate impacts both the demand and supply side of energy. Due to daily or seasonal changes the demand for energy patterns is changing. On the supply side due to increasing temperatures and variability in climate parameters it impacts estimated energy outputs of projects as well as operational costs. However, there are limited studies in the North American region that quantitatively document the impact of a climate parameter on the future of wind and solar energy.[10] Some broad impacts anticipated from climate change are noted below:[11]

Wind Energy

- Changes to wind speed: could impact energy assessments
- Changes in temperature: with increased temperatures the air density could reduce energy outputs

[10] Climate change impacts on the energy system: a review of trends and gaps. Cronin, J., Anandarajah, G. & Dessens, O. Climatic Change volume 151, August 2018.
[11] Climate change impacts on renewable energy generation. A review of quantitative projections. Kepa Solaun, Emilio Cerdá. Renewable and Sustainable Energy Reviews

- Changes in seasonal or daily wind: could disrupt correlation between wind energy and grid load demand
- Rising sea levels: could damage offshore wind farm infrastructure

Solar Energy
- Changes in mean temperatures: increased global temperatures could reduce cell efficiency
- Changes in solar irradiation, dirt, snow, precipitation etc.: increase in these variables could reduce energy output

Integration of energy storage with wind and solar projects is a way to help make use of generated energy more efficiently.

Wildfire Risk Mitigation

Wildfires continue to become more frequent and intense throughout the region. Continued growth of the wildland urban interface and the impacts of climate change mean that it is imperative that utilities continue to lead the way in implementing innovative strategies to keep customers and communities safe.

As a leading provider of safe and reliable electricity throughout the west, PacifiCorp has worked closely with stakeholders and experts to develop wildfire mitigation plans that ensure safe and reliable service and prioritize customer and community safety. PacifiCorp's wildfire mitigation plans, which describe the investments and protocols needed to construct, maintain, and operate electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire, are guided by the following core principles:

- Frequency of ignition events related to electric facilities can be reduced by engineering more resilient systems that experience fewer fault events.
- When a fault event does occur, the impact of the event can be minimized using equipment and personnel to shorten the duration to isolate the fault event.
- Systems that facilitate situational awareness and operational readiness are central to mitigating fire risk and its impacts.
- A successful plan must also consider the impact on customers and communities within the overall imperative to provide safe, reliable, and affordable electric service.

PacifiCorp's plans, which outline a risk-based, balanced, and integrated approach, contain six critical focus areas of planning and execution for a reliable and resilient energy future: (1) Risk analysis and drivers, (2) Situational awareness, (3) Inspection and correction, (4) Vegetation management, (5) System hardening, and (6) Operational practices.

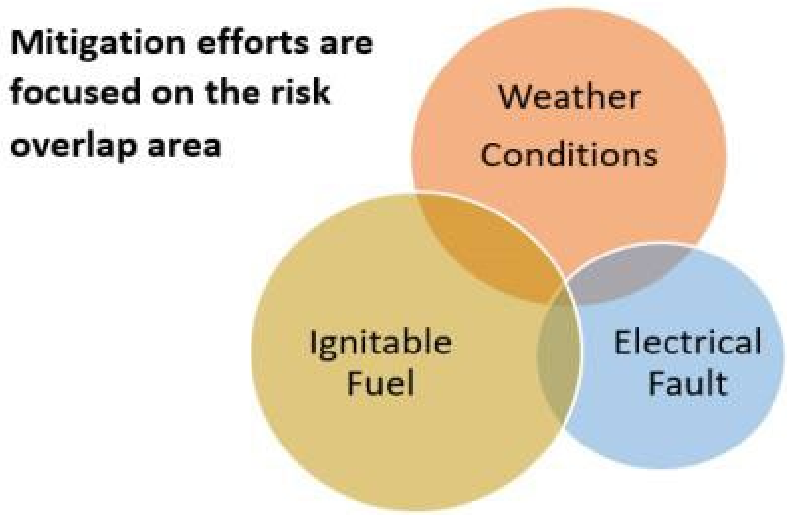
The company continues to build on over a century of wildfire mitigation experience and three decades of information gathering and analysis. PacifiCorp's planning focus areas above are intended to ensure that we continue to serve customers safely and reliably. As new analyses, technologies, practices, network changes, environmental influence or risks are identified, changes to address them may be incorporated into future iterations of the plans.

Risk Analysis and Drivers

PacifiCorp's risk evaluation process employs the concept that risk is the product of the likelihood of a specific risk event multiplied by the impact of the event. The likelihood, or probability, of an event is an estimate of a particular event occurring within a given time frame. The impact of event is an estimate of the effect when an event occurs. Impact can be evaluated using a variety of factors, including considerations centered on health and safety, the environment, customer satisfaction, system reliability, the company's image and reputation, and financial implications.

A disruption of normal operations on the electrical network, called a "fault", could be a possible ignition source for wildfire. Under certain weather conditions and in the vicinity of wildland fuels, an ignition can grow into a harmful wildfire, potentially even growing into a catastrophic fire causing great harm to people and property. This general relationship is shown in the Figure 5.1.

Figure 5.1 – Wildfire Risk Mitigation Focus Areas



Therefore, PacifiCorp's risk analysis first concentrates on weather conditions and ignitable fuels, to identify the geographic areas at the greatest risk of catastrophic fire. The analysis also explores location specific fire history, recorded causes, the acreage impact of the fires, the seasonality of fires, and long-term trends in weather patterns and climatological risk. The analysis further considers historical outage data, reflecting the best available data regarding the potential for faults on the electrical system.

These faults, when experienced during fire risk time periods in locations with the greatest risk for catastrophic fire, reflect the best available data to utilities to correlate an identifiable event on the electric network to the risk of utility-related wildfire. There is a logical physical relationship, when a fault occurs it could result in a spark, thus there is a risk of fire, therefore these events are classified as ignition risk drivers. An unplanned outage, which is when a line is unintentionally de-energized, is most often rooted in a fault. Accordingly, the company has closely analyzed the causes and frequency of outages. This analysis is designed to determine which mitigation strategies are best suited to minimize fault events, thereby reducing the risk of fire. Additionally, this analysis highlights geographic locations that present the greatest risk, allowing PacifiCorp to focus efforts.

Situational Awareness

Situational awareness involves knowledge of the conditions that impact the potential for wildfire ignition and spread. Increasing its situational awareness of such conditions helps an electric utility implement operational strategies, respond to local conditions, and minimize the wildfire risk by making mitigation strategies more effective.

Pacific Power's approach to situational awareness includes the acquisition of data to forecast and assess the risk of potential or active events to inform operational strategies, response to local conditions, and decision making. These key components, as outlined below, rely on a core team of utility meteorologists to guide, execute, and continuously evolve.

Weather Stations

PacifiCorp obtains data regarding local conditions from many sources and uses the data to adjust its operations in both the short and long term. Local weather data remains a key input to this process and PacifiCorp's overall situational awareness capability. To supplement existing local weather data and conditions, PacifiCorp installs and operates weather stations in high-risk locations. Additionally, PacifiCorp continues to evaluate the need for additional micro weather data in areas with a high-risk of wildfires that could threaten the public and property to obtain more granular local weather data. As the company's overall plan and situational evolves, PacifiCorp intends to evaluate this program for future expansion should additional or different data be needed.

Meteorology

The ability to gather, interpret, and translate data into an assessment of utility specific risk and inform decision making protocols is another key component of PacifiCorp's situational awareness capability. To support this effort, PacifiCorp has developed a meteorology department within the company's broader emergency management department. The objectives of this department are to supplement the company's longer term risk analysis capabilities with a real time risk assessment and forecasting tool, identify and close any forecasting data gaps, manage day to day threats and risks, and recommend changes to operational protocols during periods of elevated risk.

Inspection and Correction

Inspection and correction programs are the cornerstone of a resilient system. These programs are tailored to identify conditions that could result in premature failure or potential fault scenarios, including situations in which the infrastructure may no longer be able to operate per code or engineered design, or may become susceptible to external factors, such as weather conditions.

PacifiCorp performs inspections on a routine basis as dictated by both state-specific regulatory requirements and PacifiCorp-specific policies. When an inspection is performed on a PacifiCorp asset, inspectors use a predetermined list of condition codes and priority levels to describe any noteworthy observations or potential noncompliance discovered during the inspection. Once recorded, PacifiCorp uses condition codes to establish the scope of and timeline for corrective action to make sure that the asset is in conformance with National Electric Safety Code (NESC) requirements, state-specific code requirements and/or PacifiCorp specific policies. This process is designed to correct conditions while reducing impact to normal operations.

The historic inspection and correction programs are effective at maintaining regulatory compliance and managing routine operational risk. They also mitigate some wildfire risk by identifying and correcting conditions which, if uncorrected, could ignite a fire. Recognizing the growing risk of wildfire, PacifiCorp plans to supplement its existing programs, in collaboration with state regulators and stakeholders, to further mitigate the growing wildfire specific operational risks and create greater resiliency against wildfires. These changes include the creation of a fire threat classification for specific conditions, an increase of inspection frequencies in high-risk locations, and the reduction of correction timeframes for fire threat conditions.

Vegetation Management

Vegetation management is generally recognized as a significant strategy in any Wildfire Mitigation Plan. Vegetation coming into contact with a power line could be a source of fire ignition. Thus, reducing vegetation contacts reduces the potential of an ignition originating from electrical facilities. While it is impossible to eliminate vegetation contacts completely, at least without radically altering the landscape near power lines, a primary objective of PacifiCorp's existing vegetation management program is to minimize contact between vegetation and power lines. This objective is in alignment with core Wildfire Mitigation Plan efforts, and continuing dedication to administering existing programs is a solid foundation for PacifiCorp's Wildfire Mitigation Plan efforts. To supplement the existing program, PacifiCorp vegetation management implements additional Wildfire Mitigation Plan strategies such as annual vegetation patrols, extended clearances, and radial pole clearing in high-risk locations.

System Hardening

PacifiCorp's electrical infrastructure is engineered, designed, and operated in a manner consistent with prudent utility practice, enabling the delivery of safe, reliable power to all customers. When installing new assets, PacifiCorp is committed to incorporating the latest technology and engineered solutions. When conditions warrant, PacifiCorp may engage in strategic system hardening, which means replacing existing assets (or, in some circumstances, modifying existing assets using a new design and additional equipment) to make the assets more resilient. Recognizing the growing risk of wildfire, PacifiCorp plans to supplement existing asset replacement projects with system hardening programs designed to mitigate specific operational risks associated with wildfire.

System hardening programs are designed in reference to the equipment on the electrical network that could be involved in the ignition of a wildfire or be subject to an existing wildfire event. In general, system hardening programs attempt to reduce the occurrence of events involving the emission of sparks (or other forms of heat) from electrical facilities or reduce the impact of an existing wildfire on utility infrastructure. System hardening programs represent the greatest long-term mitigation tool available for use by electric utilities. The phasing and prioritization of such programs is therefore focused on locations that present the greatest risk through the line rebuild program.

Additionally, no single system hardening program mitigates all wildfire risk related to all types of equipment. Therefore, different system hardening components are grouped together as part of PacifiCorp's line rebuild program to address different factors, different circumstances, and different geographic areas. Each project included in the line rebuild program described below, however, shares the common objective of reducing overall wildfire risk associated with the design and type of equipment used to construct electrical facilities.

It must be emphasized, however, that system hardening cannot prevent all ignitions, no matter how much is invested in the electrical network. Equipment does not always work perfectly and, even when manufactured and maintained properly, can age and fail; in addition, there are external forces and factors impacting equipment, including from third parties and natural conditions. Therefore, PacifiCorp cannot guarantee that a spark or heat coming from equipment owned and operated by PacifiCorp will never ignite a wildfire. Instead, PacifiCorp seeks to reduce the potential of an ignition associated with any electrical equipment. To this end, PacifiCorp plans to make investments with targeted system hardening programs.

Line Rebuild Program

PacifiCorp has evaluated specific areas for system hardening work based on the company's risk assessment methodology where bare overhead wire may be replaced with covered conductor. Where appropriate, poles will either be replaced or made more fire resilient (by fire protective treatment methods). Additionally, where conductor diameters do not support fault current properly (due to the limited arc energy they can tolerate), they will be replaced, generally with covered conductor. In all, the end effect will be more tolerant to incidental contact, while also being certain to tolerate fault event arc energy levels.

<u>Covered Conductor</u>

Historically, most high voltage power lines in the United States, and in PacifiCorp's service territory, were installed with bare overhead conductor. As the name "bare" suggests, the wire is all metal and exposed to the air. For purposes of wildfire mitigation, a new conductor design has emerged as an industry best practice. Most of the projects in the Line Rebuild Program will involve the installation of covered conductor. Sometimes, with some variations in products, covered conductor is also called spacer cable, aerial cable, or tree cable.

The dominant characteristic of covered conductor is that the metal conductor which carries electricity is sheathed in a plastic covering. As a comparison for the lay person, covered conductor is like an extension power cord that you might use in your garage. The plastic coating provides insulation for the energized metal conductor inside the plastic coating. To be clear, covered conductor is not insulated enough for people to directly handle an energized high voltage power line (as discussed below). But the principle is the same. The plastic sheathing provides an insulating effect. It is this insulating effect which reduces the risk of wildfire, by greatly reducing the number of faults that would have occurred had bare conductor been used.

Variations in covered conductor products have been used in the industry for decades. Due to many operating constraints, however, use of covered conductor tended to be limited to locations with extremely dense vegetation where traditional vegetation management was not feasible or efficient. Recent technological developments, however, have markedly improved covered conductor products, reducing the operating constraints historically associated with the design. These advances have improved the durability of the project and reduced the impact of thermal insulation (i.e. because bare wires are exposed to air, bare wires can cool easier). There are still logistical challenges with covered conductor. Above all, the wire is heavier, especially when carrying snow or ice, meaning that more and/or stronger poles may be required when using covered conductor. And the product itself is more expensive than bare conductor.

The wildfire mitigation benefits of covered conductor are significant. As discussed in the risk assessment section, a disruption on the electrical network, a fault, can result in emission of spark or heat that could be a potential source of ignition. Covered conductor greatly reduces the potential of many kinds of faults. For example, contact from object is major category of real-world faults which can cause a spark. Whether it is a tree branch falling into a line or a Mylar balloon carried by the wind drifting into a line, contact from those objects with energized bare conductor causes the emission of sparks. If those same objects contact covered conductor, the wire is insulated enough that there are no sparks. Likewise, many equipment failures are a wildfire risk because the equipment failure then allows a bare conductor to contact a grounded object. Consequently, covered conductor greatly reduces the risk of ignition associated with most types of equipment failure. For example, if a cross arm breaks, the wire held up by the cross arm often falls to the ground (or low and out of position, so that the wire might be contacting vegetation on the ground or the pole itself). In those circumstances, a bare conductor can emit sparks (or heat) that can cause an ignition. The use of covered conductor, in those exact same circumstances, would almost certainly not lead to an ignition, because the insulation around the wire is sufficient to prevent any sparks and limit energy flow, even when there is contact with an object.

Covered conductor is especially well suited to reduce the occurrence of faults reasonably linked with the worst wildfire events. Dry and windy conditions pose the greatest wildfire risks. Wind is the driving force behind catastrophic wildfire spread. At the same time, wind has distinct and negative impacts on a power line. The wind blows objects into lines; a strong wind can cause equipment failure; and even parallel lines slapping in the wind can cause sparks. Covered conductor specifically reduces the potential of a catastrophic ignition event, because covered conductor is especially effective at limiting the kinds of faults that occur when it is windy. Taken together, these substantial benefits warrant the use of covered conductor in areas with a high wildfire risk.

In sum, at a very basic level, covered conductor is safer overall compared to bare conductor. Not only does covered conductor reduce the risk of wildfire, but it is also less dangerous to contact a covered conductor compared to a similar voltage bare conductor. Combined with the substantial wildfire mitigation benefits, covered conductor is the preferred design for rebuild projects. There are, however, unique challenges implicated in making it harder to spot a low-hanging or downed line.

PacifiCorp also evaluated the costs and benefits of underground design for the rebuild projects. The potential wildfire mitigation benefits are undeniable. While an underground design does not eliminate every ignition potential (i.e., because of above-ground junctions), it is the most effective design to most dramatically reduce the risk of any utility-related ignition. Unfortunately, because of cost and operational constraints, the functional realities of underground construction prevent widespread application as a wildfire mitigation strategy. Nonetheless, PacifiCorp is using an underground design as part of the rebuild projects when functional and cost-effective. Through the design process, each rebuild project is assessed to determine whether sections of the rebuild should be completed with underground construction. As a practical matter, the great majority of the rebuilds will be covered conductor. This outcome is consistent with emerging best practices. Utilities in geographic areas with extreme wildfire risk, including in California and Australia, are trending heavily towards use of covered conductor, with limited applications of underground construction where appropriate. Indeed, sourcing material for the planned projects is challenging because of the industry trend towards use of covered conductor as a primary wildfire mitigation strategy. On a related note, the company remains willing to consider additional underground applications. Some communities and landowners may prefer, for aesthetic reasons, to pursue a higher cost underground alternative. Consistent with governing electric service regulations, PacifiCorp will work with communities or individual landowners who are willing to pay the incremental cost and obtain the necessary legal entitlements for underground construction, if covered conductor is the least cost option for a rebuild project.

Non-Wooden Poles

Traditionally, overhead poles are replaced or reinforced within PacifiCorp's service territory consistent with state specific requirements and prudent utility practice. When a pole is identified for replacement, typically through routine inspections and testing, major weather events, or joint use accommodation projects, a new pole consistent with engineering specifications suitable for the intended use and design is installed in its place. Engineering specifications typically reflect the use of wooden poles which is consistent with prudent utility practice and considered safe and structurally sufficient to support overhead electrical facilities during standard operating conditions. However, the use of alternate non-wooden construction, such as steel or fiberglass, can provide additional structural resilience in high-risk locations during wildfire events and, therefore, aid in restoration efforts.

In addition to the installation of non-wooden solutions as a part of standard replacement programs or mechanisms in priority locations with increased risk, certain wooden poles may also be replaced with non-wooden solutions in conjunction with other wildfire mitigation system hardening programs. For example, as a part of covered conductor installation, the strength of existing poles is evaluated. In many cases, the strength of existing poles may not be sufficient to accommodate the additional weight of covered conductor. In these instances, the existing wooden pole is upgraded to support the increased strength requirements and, when present in high priority locations, replaced with a non-wooden solution for added resilience.

Non-Expulsion Fuses

Overhead expulsion fuses serve as one of the primary system protection devices on the overhead system. The expulsion fuse has a small metal element within the fuse body that is designed to melt when excessive current passes through the fuse body, interrupting the flow of electricity to the downstream distribution system. Under certain conditions, the melting action and interruption technique will expel an arc out of the bottom of the fuse tab. To reduce the potential for ignition resulting from fuse operation, PacifiCorp has identified alternate methodologies and equipment that do not expel an arc for installation within high-risk locations. PacifiCorp plans to replace expulsion fuses with non-expulsion fuses as a part of the high-risk locations line rebuild program in conjunction with the installation of covered conductor.

Advanced System Protection and Control

Microprocessor relays provide multiple wildfire mitigation benefits. They are able to exercise programmed functions much faster than an electro-mechanical relay and above all, the faster relay limits the length and magnitude of fault events. After a fault occurs, energy is released, posing a risk of ignition, until the fault is cleared. Reducing the duration of a fault event reduces the risk that the fault might result in a fire.

Additionally, microprocessor relays also allow for greater customization to address environmental conditions through a variety of settings and are better able to incorporate complex logic to execute specific operations. These functional features allow for the company to use more refined settings for application during periods of greater wildfire risk, which will be discussed in the section below.

Finally, in contrast to electro-mechanical relays, microprocessor relays retain event logs that provide data for fault location and later analysis. In certain circumstances, this information can help the company locate and correct a condition prior to the condition leading to a more serious event. At a minimum, such information facilitates better knowledge of the network, possibly shaping future mitigation strategies. PacifiCorp is continuing to replace and upgrade electro-mechanical relays with microprocessor relays throughout high-risk areas. As part of replacing an electro-mechanical relay, the associated circuit breaker or other line equipment may also be replaced, as appropriate to facilitate the functionality of a microprocessor relay.

Operational Practices

System Operations

Adjustments to power system operations can help mitigate wildfire risk. System operations adjustments generally include the modification of relay settings for protective devices on distribution lines or changes to re-energization testing protocols. These adjustments are not universally applied to power system operations in order to balance wildfire mitigation with potential impacts to customers associated with additional outages.

Elevated Fire Risk Settings

Line protective devices, such as line reclosers, are currently deployed on various transmission and distribution lines throughout Pacific Power’s service territory. When a line trips open due to fault activity, reclosers can be programmed to momentarily open, allow the fault to dissipate, then reclose in an effort to test if the fault is temporary. The reclosing function gives the ability to restore service on a line that has tripped while maintaining the option to open again if the fault persists. If the fault is permanent, the recloser will operate and stay open (known as the “lock out” state) until the line has been deemed ready for re-energization.

In general, recloser operation is beneficial because it reduces the number of sustained outages and improves customer reliability. The reclosing function, however, implicates some degree of ignition risk because additional energy can be released if a fault persists. When a fault is detected on the line, a recloser will trip and reclose based on predetermined settings to re-energize the line. If the fault is temporary in nature and is no longer present upon the reclose operation, the line will re-energize resulting in limited impact to customers. If the fault persists, however, reclosing can, depending on the circumstances, potentially result in arcing or an emission of sparks. Accordingly, a strategic balance between customer reliability goals and wildfire mitigation goals is required.

Pacific Power has used recloser disabling strategies on transmission lines for many years, and it has employed more frequent disabling of reclosers on transmission lines in recent years because of the increased wildfire risk. PacifiCorp has been able to use these strategies without having too great of an impact on customer reliability. With wildfire risk continuing to increase, PacifiCorp is implementing additional strategies on the distribution network, including the use of modified and more sensitive protection and control schemes, referred to as Elevated Fire Risk (EFR) settings

To mitigate impacts to customer reliability, PacifiCorp generally does not disable reclosing seasonally. Instead, PacifiCorp leverages the daily risk assessment process and situational awareness reports generated by meteorologists and takes a risk-based approach to the implementation of EFR settings. For example, when meteorological conditions of increased wildfire risk occur, an alternative operating mode may sometimes be used to reduce the number of reclose attempts, increase the open interval time between trip and reclose operations, or set the recloser to lock out upon a single trip event. Moving forward, PacifiCorp plans to continue evaluating situational awareness, customer outages and other information to further optimize the settings and implement EFR settings as needed.

Re-energization Practices

Risk-based changes to re-energization practices is very similar to the implementation of EFR settings in that it also requires a balance between customer reliability and wildfire mitigation. If a breaker or recloser has “locked-out” – meaning that it has opened and no longer conducts electricity – a system operator or field personnel will sometimes “test” the line. To test the line, the system operator or field personnel will close the device, thereby allowing the line to be re-energized. If the fault has cleared, then the system will run normally. If the fault has not cleared, the device will lock out again. If the device locks out again, the system operator then knows that additional investigation or work will be required before the line can be successfully re-energized. Because faults are often temporary, line-testing can be an efficient tool to maintain customer reliability similar to the use of reclosing described in the previous section. At the same time, line-testing can potentially result in arcing or an emission of sparks if a fault has not yet cleared when the line is tested. To mitigate this risk, PacifiCorp requires an appropriate level of patrol prior to line testing, depending on local circumstances. Moving forward, PacifiCorp plans to further incorporate situational awareness reports to continue informing re-energization protocols during periods of elevated risk.

Field Operations

During fire season, PacifiCorp modifies the way it operates in the field to further mitigate wildfire risk. Field operations consider the local weather and geographic conditions that may create an elevated risk of wildfire. These practices are targeted to reduce the potential of direct or indirect causes of ignition during planned work activities, fault response and outage restoration.

PacifiCorp personnel working in the field during fire season mitigate wildfire risk through a variety of tactics. Routine work, such as condition correction and outage response, poses some degree of ignition risk, and, in certain circumstances, crews modify their work practices and equipment to decrease this risk. In the extremely unlikely event that a fire ignition occurs while field crews or other PacifiCorp personnel are working in the field (collectively “field personnel”), such field personnel are equipped with basic tools to extinguish small fires.

Work Restrictions

PacifiCorp field operations can mitigate some wildfire risk by managing the way that field work is scheduled and performed. To effectively manage work during fire season, area managers regularly review local fire conditions and weather forecasts provided to them as part of PacifiCorp's monitoring program – discussed in the situational awareness section below.

During fire season generally, field operations managers are encouraged to defer any nonessential work at locations with dense and dry wildland vegetation, especially during periods of heightened fire weather conditions. If essential work needs to be performed in high-risk locations and other areas with appreciable wildland vegetation, certain restrictions may apply, including:

- **Hot Work Restrictions.** Field operations managers are encouraged to evaluate whether work should be performed during a planned interruption, rather than while a line is energized.
- **Time of Day Restrictions.** Field operations managers are encouraged to consider using alternate work hours to accommodate evening and night work when there may be less risk of ignition.
- **Wind Restrictions.** Field personnel are encouraged to defer work, if feasible, when there are windy conditions at a particular work site.
- **Driving Restrictions.** Field personnel are encouraged to keep vehicles on designated roads whenever operationally feasible.
- **Worksite Preparation.** If wildland vegetation posing an ignition risk is prevalent at a worksite, and the work to be performed involves the potential emission of sparks from electrical equipment, field personnel working during fire season are encouraged to remove vegetation at the work site where allowed in accordance with land management/agency permit requirements, especially when there is dry or tall wildland grass. In addition to clearing work, the water truck resources, discussed below, are strategically assigned to sometimes accompany field personnel working in a wildland area during fire season, especially in high-risk locations. Depending on local conditions, dry vegetation in the immediate vicinity may be sprayed with water before work as a preventative measure.

Additional Labor Resources

Some wildfire mitigation activities require the time of field personnel, including in two key areas: (a) supporting system operations in administering the procedures discussed above and (b) responding to outages during fire season.

Under normal operating procedures, system operators and field personnel work together daily to manage the electrical network. In many situations, system operators depend on field personnel to gather information and assess local conditions. As discussed above, there are system operations procedures during wildfire season for disabling automatic recloser functions and limiting line-testing. Consequently, system operators need field personnel to gather information and assess local conditions during fire season more frequently than would otherwise be required under normal operating procedures. The requests from system operators may be varied, ranging from a simple phone call to confirm that it is raining in a particular area, to a much more time-intensive request, such as a full line patrol on a circuit.

Field personnel may also spend some additional time when responding to an outage during fire season. After a fault result in an outage, all or part of a circuit might remain de-energized while restoration work is performed, depending on the design, loading conditions and sectionalizing capability of the circuit experiencing the outage. Occasionally, additional foreign objects, such as tree limbs or other debris, can come into contact with the de-energized line and remain undetected throughout the duration of restoration efforts. Under normal operating procedures and consistent with prudent utility practices, a line is typically re-energized as soon as restoration work is complete. Consequently, a re-energized line could immediately experience a new fault if some contact between the line and foreign object had occurred while restoration work was being performed. The new fault would, of course, present additional wildfire risk, because of the potential of a spark being emitted because of a fault occurring when the line was re-energized. To mitigate this risk, field operations may perform some amount of line patrol on certain de-energized sections of the circuit, notably during fire season and particularly in high-risk locations dependent on current conditions at the work site and the duration of the restoration work. Depending on the circumstances, this extra patrol might be done just before or just after re-energizing the line. Typically, this type of line patrol does not involve a close inspection of any facility; instead, it is a quick visual assessment specifically targeted to identify obvious foreign objects that may have fallen into the line during restoration work.

Equipment and Tool Purchases

In addition to changes in work practices, PacifiCorp invests in tools and equipment to mitigate wildfire risk. These investments include (1) vehicles, (2) personal suppression equipment, and (3) water trailers.

Vehicles

Vehicles can be a source of ignition. As discussed above, field operations personnel are instructed to stay on designated roads during fire season, as feasible, and to avoid vegetation which could contact the undercarriage of parked vehicle. To further mitigate any wildfire risk associated with the use of vehicles, field operations plan to convert, over time, the vehicle exhaust configuration of work trucks. To accomplish this objective, field operations will strategically convert some vehicles in districts with the greatest amount of FHCA. Long term, when new vehicles are purchased, PacifiCorp plans to purchase trucks with a vehicle exhaust configuration which minimizes ignition risk.

Basic Personal Suppression Equipment

Personal safety is the priority, and PacifiCorp field personnel are encouraged to evacuate and call 911 if necessary. Field personnel working in high-risk locations maintain the capability to extinguish a small fire that ignited while they are working in the field. Field personnel should attempt suppression only if the fire is small enough so that one person can effectively fight the fire while maintaining their personal safety. All field personnel working in high-risk locations during fire season will have basic suppression equipment available onsite, because field utility trucks typically carry the following equipment: (1) fire extinguisher; (2) shovel; (3) Pulaski; (4) water container; and (5) dust mask. The water container should hold at least five gallons and may be a pressurized container or a backpack with a manual pump (or other).

Water Truck Resources

PacifiCorp has water trucks that field operations use to mitigate against wildfire risk. For clarity, these resources are not dispatched to reported fires (i.e., like a fire truck). Instead, PacifiCorp resources are strategically assigned to accompany field personnel if conditions warrant. For example, if it is necessary to perform work in high-risk locations during a period in which there is a Red Flag Warning, PacifiCorp field operations may schedule a water truck to join field personnel working in the field. As discussed above, the water truck can be used to help prep the site for work. By watering down dry vegetation in the work area, any chance of an ignition can be minimized. In the extremely unlikely event there was an ignition, the water truck could be used to assist in the suppression of a small fire. Field operations currently has eight water trucks for use in such applications. In addition, the company plans to purchase two water trucks and one trailer.

Transmission-Based Reliability

PacifiCorp is required to meet mandatory FERC, (NERC), and WECC reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by California Independent System Operator (CAISO) RC West as the NERC Reliability Coordinator for PacifiCorp. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

With the increasing number of variable resources added to the grid throughout the west, PacifiCorp's ability to meet federal reliability directives depends increasingly on an interconnected transmission system across the western states and on the ability to move electricity throughout the six states served by the company. PacifiCorp's planning process ensures that the company is developing a portfolio that balances sufficient supply to serve all PacifiCorp customers with sufficient resources and transmission to ensure that electricity can be moved from generation sources to the communities served.

PacifiCorp's interconnection to other balancing authority areas and participation in the Energy Imbalance Market provide access to markets and promote affordable and reliable service to PacifiCorp's customers. Further, PacifiCorp's transmission capacity provides benefits to customers by increasing reliability and allowing additional generation to interconnect to serve customer load, as well as allowing PacifiCorp flexibility in designing generating resources for reserve capacity to comply with mandatory reliability standards.

Federal Reliability Standards

The Energy policy Act of 2005 included expanded reliability-related elements of the federal regulatory structure and directed the FERC to institute mandatory reliability standards that all users of the bulk electric system (BES) must follow.

FERC delegated the authority to NERC to develop reliability standards to ensure the safe and reliable operation of the BES in the United States under a variety of operating conditions. These standards are a federal requirement and are subject to oversight and enforcement by the WECC, NERC, and FERC. PacifiCorp is subject to compliance audits every three years and may be required to prove compliance during other reliability initiatives or investigations.

The transmission planning standards (TPL Standards), found within the NERC transmission reliability standards, specify that transmission system planning performance requirements to develop a BES that will operate reliably over a broad spectrum of system conditions. They also require study of a wide range of probable contingencies in short-term (1-2 years), medium term (5 years) and long-term (10-20 years) scenarios to ensure system reliability. Together with regional planning criteria, such as those established by the NERC/WECC, and utility-specific planning criteria, the TPL Standards define the minimum transmission system requirements to safely and reliably serve customers.

In addition to the TPL Standards, PacifiCorp is also required to comply with FERC Order 1000 and completed per Attachment K of the Open Access Transmission Tariff (OATT) which requires PacifiCorp to participate in regional transmission planning processes that satisfy the transmission planning principles of FERC Order 890 and produces a regional transmission plan. To meet this requirement PacifiCorp is a member of the NorthernGrid regional planning association. The development of the regional transmission plan ensures the regional reliability is maintained and/or enhanced with the addition of new planned generation and transmission projects while reliably serving PacifiCorp customers.

Power Flow Analyses and Planning for Generator Retirements

PacifiCorp transmission planning has performed various coal unit retirement assessments analyzing potential impacts to the transmission system. These studies are performed outside of the IRP process under PacifiCorp's OATT processes which includes either 1) a customer request to perform a consulting study; or 2) a customer request to un-designate a network resource which then triggers a system impact and facilities study if the study determines that mitigations are required due to retirement.

Past studies have found that a number of factors are critical in determining transmission system impacts and necessary mitigation, if any. These factors include: 1) location of the unit(s) to be retired, 2) the number of units being retired, 3) the size of the units being retired, 4) year of retirement, and 5) location, size, and type of replacement resources, if any. Based on the location, number of units, and size of the retired unit/s, studies can identify if the retirement results in either thermal or voltage issues on the transmission system. A retirement of a coal unit may result in voltage issues due to lack of reactive support that was previously provided by the retired unit/s. A retirement may also result in thermal overload of the transmission system due to changes in the flows post unit retirement. As such, until official notification to PacifiCorp transmission of coal unit designation/retirement is received, all such coal retirement analysis is considered preliminary.

Transmission Investment to Support Reliability, Resiliency and Ongoing Investment in Renewables

The 2023 IRP includes several substantial transmission upgrades that will not only support the interconnection of new renewable resources but also provides reliability and resiliency to the broader transmission system.

In the eastern/central Wyoming region PacifiCorp has seen a significant amount of proposed renewable generation, specifically wind generation. However, the 230 kV system in the region has reliability challenges to support additional generation. The 2023 IRP includes several proposes transmission system upgrades to address both issues.

First is the 416-mile long 500-kV Gateway South (Segment F Mona-Clover) transmission line from the Aeolus substation near Medicine Bow, WY to Clover substation near Mona, Utah. The construction of Gateway South directly connects eastern Wyoming to central Utah while enhancing the reliability throughout the PacifiCorp-served regions. Connecting into the Mona/Clover market hub provides additional flexibility in the use of least-cost resources from eastern Wyoming or southern Utah to serve customer load. This segment will connect to the already completed Gateway Central lines that lead to the Salt Lake City region.

Next is the 200-mile 500-kV Gateway West Subsegment D3 (Anticline-Populus) transmission line from Anticline substation in central Wyoming to Populus substation in southeastern Idaho. This segment provides additional capacity and reliability in addition to the upgrades that have previously occurred from Gateway West Subsegment D2 which connected eastern and central Wyoming with a new 500-kV line. By extending the 500-kV system to southeastern Idaho further flexibility is provided to allow low-cost resources to be utilized reliably. This segment will also connect to the already completed Gateway Central transmission segments creating a regional triangle of transmission which provides significant reliability to the system.

Additionally, the construction of the remaining portions of PacifiCorp's Gateway West Subsegment D1 which include the rebuild of an existing 230 kV transmission line along with a new, parallel between Windstar and Aeolus substations has been identified. The Subsegment provides further reinforcement of the 230-kV transmission system in the eastern Wyoming region connecting it to the 500-kVsystem at Aeolus substation.

Finally, a new 150-mile 500-kV transmission line between Shirley Basin substation in eastern Wyoming and Anticline substation in central Wyoming is included in the 2023 IRP. This new 500-kV line provides redundancy to the eastern/central Wyoming transmission system that will not only effectuate the interconnection of additional low cost, renewable resources, but add to system reliability and resiliency.

Together, the addition of these transmission upgrades improves reliability in PacifiCorp served regions by relieving the stress on the transmission system in the respective areas. For example, the additions in Wyoming will relieve the stress on the existing, underlying 230-kV transmission system while improving the reliability in that region. Similarly, the addition of the Gateway South line in the central Utah area unloads the underlying 345-kV transmission system improving reliability in that region. Essentially the 500-kV line brings two distant areas close to each other while maintaining the regional reliability. Utah and the surrounding system will benefit from both completion of the Gateway Central transmission projects as with increased transfer capability and increased resilience during outage conditions.

Based on interconnection studies performed by PacifiCorp, the inclusion of these segments will allow for the addition of a significant amount of renewable generation. PacifiCorp's legacy serial queue and more recent cluster study results support the inclusion of these upgrades.

In addition, the 2023 IRP also includes the 290-mile, 500 kV Gateway Segment H (Boardman-Hemingway) transmission line. This line will provide increased reliability to PacifiCorp's transmission system by creating an additional link between its eastern and western systems. This will allow resources to be transferred between the two regions more efficiently.

CHAPTER 6 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

- On both a capacity, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability across all hours in both the summer and winter.
- Capacity assessment across more than the coincident peak is necessary due to the evolution of the company's portfolio to include more wind, solar, and storage resources. Solar provides significant output during the summer coincident peak, but no output in many other summer hours. As a result, summer risks cannot easily be identified by looking at load alone. Instead, PacifiCorp evaluated the resources available relative to the expected load in every hour, and the hour with the lowest resources as a percentage of the hourly load in each season determines the planning reserve margin (PRM) achieved for that season in that year.
- The company's load obligation is calculated based on projected load less private generation, energy efficiency savings, and demand response, including interruptible load.
- A 2022 Private Generation Long-Term Resource Assessment (2023-2042) study prepared by DNV produced estimates on private generation penetration levels specific to PacifiCorp's six-state territory. The study provided expected penetration levels by resource type, along with high and low penetration sensitivities. PacifiCorp's 2023 IRP load and resource balance treats base case private generation penetration levels as a reduction in load.
- After accounting for a minimum 13 percent PRM target, load growth, and resource retirements from the preferred portfolio, plus accounting for the level of potential market purchases assumed in the 2023 IRP, and after incorporating future energy efficiency savings from the preferred portfolio, PacifiCorp's system is capacity deficient (before adding proxy resources) over in the summer beginning in 2026, and the winter peaks throughout the twenty-year planning period.
- The uncertainty in the company's load and resource balance is increasing as PacifiCorp's resource portfolio and customer demand evolve over time. While PacifiCorp took steps to better reflect the relationship between renewable resources and load in the 2021 IRP, additional opportunities to better characterize these relationships remain. Similarly, customer demand may be influenced by climate change directly as well as indirectly through electrification, with uncertain impacts on future demand. These resources and load relationships ultimately drive the frequency and characteristics of the relatively extreme conditions that are most likely to trigger reliability shortfalls.

Introduction

This chapter presents PacifiCorp's assessment of its load and resource balance. PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system are summarized in Volume II, Appendix A (Load Forecast Details). The summary-level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, with and without available Market purchases, assumed coal unit retirements and incremental new energy efficiency savings from the preferred portfolio, before adding new generating resources.

System Coincident Peak Load Forecast

The system coincident peak load is the annual maximum hourly load on the system. The 2023 IRP relies on PacifiCorp's May 2022 load forecast. Table 6.1 shows the annual summer coincident peak load stated in megawatts (MW) as reported in the capacity load and resource balance before any load reductions from energy efficiency and private generation. The system summer peak load grows at a compound growth rate (CAGR) of 1.70 percent over the period 2023 through 2042.

Table 6.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency and Private Generation (MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
System	11,033	11,427	11,747	11,758	12,051	12,485	12,683	12,815	13,123	13,209
	2033	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
System	13,347	13,512	13,692	13,953	14,118	14,300	14,464	14,672	14,882	15,187

Existing Resources

Thermal Plants

Table 6.2 lists PacifiCorp's existing coal-fueled plants and Table 6.3 lists existing natural-gas-fueled plants. The "Retirement Year" reflects the year a resource retires or converts to natural gas as reflected in the preferred portfolio.

Table 6.2 – Coal Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Assumed End of Life Year	Nameplate Capacity (MW)
Colstrip 3	10	Montana	2025*	74
Colstrip 4	10*	Montana	2029	74
Craig 1	19	Colorado	2025	82
Craig 2	19	Colorado	2028	79
Dave Johnston 1	100	Wyoming	2028	99
Dave Johnston 2	100	Wyoming	2028	106
Dave Johnston 3	100	Wyoming	2027	220
Dave Johnston 4	100	Wyoming	2039	330
Hayden 1	24	Colorado	2028	44
Hayden 2	13	Colorado	2027	33
Hunter 1	94	Utah	2031	418
Hunter 2	60	Utah	2032	269
Hunter 3	100	Utah	2032	471
Huntington 1	100	Utah	2032	459
Huntington 2	100	Utah	2032	450
Jim Bridger 1 GC 24	67	Wyoming	2037	354

Jim Bridger 2 GC 24	67	Wyoming	2037	359
Jim Bridger 3 GC 30	67	Wyoming	2037	349
Jim Bridger 4 GC 30	67	Wyoming	2037	351
Naughton 1 GC 26	100	Wyoming	2036	156
Naughton 2 GC 26	100	Wyoming	2036	201
Wyodak	80	Wyoming	2039	268
TOTAL – Coal				**5,246**

*Starting 2026, PacifiCorp's share of Colstrip 3 will come from Colstrip 4

Table 6.3 – Natural Gas Plants

Natural Gas -fueled	PacifiCorp Percentage Share (%)	State	Assumed End of Life Year	Nameplate Capacity (MW)
Chehalis	100	Washington	2043	500
Currant Creek	100	Utah	2045	540
Gadsby 1	100	Utah	2033	64
Gadsby 2	100	Utah	2033	69
Gadsby 3	100	Utah	2033	105
Gadsby 4	100	Utah	2033	40
Gadsby 5	100	Utah	2033	40
Gadsby 6	100	Utah	2033	40
Hermiston	100	Oregon	2037	237
Lake Side	100	Utah	2047	580
Lake Side 2	100	Utah	2049	677
Naughton 3	100	Wyoming	2036	247
TOTAL – Natural Gas				**3,137**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 5,412 MW of wind resources.
Table 6.4 shows existing wind facilities owned by PacifiCorp, while Table 6.5 shows existing wind power-purchase agreements (PPAs).

Table 6.4 – Owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)
Goodnoe Hills East	WA	94
Leaning Juniper	WA	101
Marengo I	WA	156
Marengo II	WA	78
Cedar Springs 2	WY	199
Dunlap 1	WY	111
Ekola Flats 1	WY	250
Foote Creek I	WY	41
Glenrock I	WY	99
Glenrock III	WY	39
High Plains	WY	99
McFadden Ridge 1	WY	29
Pryor Mountain	WY	240
Rolling Hills	WY	99
Seven Mile Hill	WY	99
Seven Mile Hill II	WY	20
TB Flats 1-2	WY	500
Foote Creek II-IV*	WY	43
Rock Creek I*	WY	190
Rock Creek II*	WY	400
Rock River*	WY	50
TOTAL – Owned Wind		**2,935**

*New projects added in 23 IRP

Table 6.5 – Non-Owned Wind Resources

Power Purchase Agreements	State	PPA or QF	Capacity (MW)
Wolverine Creek	ID	PPA	65
Combine Hills	WA	PPA	41
Cedar Springs I	WY	PPA	199
Cedar Springs III	WY	PPA	120
Three Buttes Power	WY	PPA	99
Top of the World	WY	PPA	200
Meadow Creek Project Five Pine	ID	QF	40
North Point	ID	QF	80
Mariah	OR	QF	10
Orem Family	OR	QF	8
Latigo	UT	QF	60
Mountain Power I	UT	QF	61
Mountain Power II	UT	QF	80
Power County Park North	UT	QF	23

Power County Park South	UT	QF	23
Spanish Fork Park 2	UT	QF	19
Tooele	UT	QF	3
Big Top	WA	QF	2
Butter Creek Power	WA	QF	5
Chopin	WA	QF	8
Four Corners	WA	QF	10
Four Mile Canyon	WA	QF	10
Orchard 1	WA	QF	10
Orchard 2	WA	QF	10
Orchard 3	WA	QF	10
Orchard 4	WA	QF	10
Oregon Trail	WA	QF	9.9
Pacific Canyon	WA	QF	8
Sand Ranch	WA	QF	10
Three Mile Canyon	WA	QF	8
Wagon Trail	WA	QF	3
Ward Butte	WA	QF	7
BLM Rawlins	WY	QF	0.1
Pioneer Park I	WY	QF	80
Cedar Creek*	ID	PPA	152
Anticline*	WY	PPA	101
Boswell*	WY	PPA	320
Cedar Springs IV*	WY	PPA	350
Two Rivers*	WY	PPA	280
TOTAL – Purchased Wind			**2535**

*New projects added in 23 IRP

Solar

PacifiCorp has a total of 87 solar projects under contract representing 3,278 MW of nameplate capacity. Of these, two recently signed solar resources also include a total of 350 MW of battery storage.

Table 6.6 – Solar Resources

Power Purchase Agreements	State	PPA or QF	Solar Capacity (MW)	Storage Capacity (MW)
Black Cap	OR	PPA	2	
Millican	OR	PPA	59	
Old Mill	OR	PPA	5	
Oregon Solar Incentive Project	OR	PPA	9	
Prineville	OR	PPA	39	
Appaloosa Solar IA	UT	PPA	120	

Appaloosa Solar IB	UT	PPA	80	
Castle Solar (Retail 1)	UT	PPA	20	
Castle Solar (Retail 2)	UT	PPA	20	
Cove Mountain	UT	PPA	58	
Cove Mtn II	UT	PPA	121	
Elektron Solar 20Yr	UT	PPA	10	
Elektron Solar 25Yr	UT	PPA	69	
Graphite	UT	PPA	79	
Horseshoe	UT	PPA	63	
Hunter	UT	PPA	99	
Milford	UT	PPA	98	
Pavant III	UT	PPA	20	
Rocket	UT	PPA	79	
Sigurd	UT	PPA	79	
Adams	OR	QF	10	
Bear Creek	OR	QF	10	
Black Cap II	OR	QF	8	
Bly	OR	QF	8	
Buckaroo Solar 1*	OR	QF	3	
Buckaroo Solar 2*	OR	QF	3	
Captain Jack*	OR	QF	2.7	
Elbe	OR	QF	10	
Ivory*	OR	QF	10	
Linkville Solar*	OR	QF	3	
Merrill	OR	QF	10	
Norwest Energy 2 (Neff)	OR	QF	10	
Norwest Energy 4 (Bonanza)	OR	QF	6	
Norwest Energy 7 (Eagle Point)	OR	QF	10	
Norwest Energy 9 Pendleton	OR	QF	6	
OR Solar 1, LLC (Sprague River)*	OR	QF	7	
OR Solar 2, LLC (Agate Bay)	OR	QF	10	
OR Solar 3, LLC (Turkey Hill)	OR	QF	10	
OR Solar 5, LLC (Merrill)	OR	QF	8	
OR Solar 6, LLC (Lakeview)	OR	QF	10	
OR Solar 7, LLC (Jacksonville)	OR	QF	10	
OR Solar 8, LLC (Dairy)	OR	QF	10	
OSLH Collier	OR	QF	10	
Pilot Rock Solar 1*	OR	QF	3	
Pilot Rock Solar 2*	OR	QF	3	
Skysol	OR	QF	54	
Solorize Rogue*	OR	QF	0.1	
Tumbleweed	OR	QF	10	
Tutuilla Solar*	OR	QF	3	

Wallowa County*	OR	QF	0.4	
Beryl	UT	QF	3	
Buckhorn	UT	QF	3	
CedarValley	UT	QF	3	
Chiloquin	UT	QF	10	
Enterprise	UT	QF	77	
Escalante I	UT	QF	77	
Escalante II	UT	QF	77	
Escalante III	UT	QF	77	
Ewauna	UT	QF	1	
Ewauna II	UT	QF	3	
Granite Mountain - East	UT	QF	78	
Granite Mountain - West	UT	QF	49	
GranitePeak	UT	QF	3	
Greenville	UT	QF	2	
Iron Springs	UT	QF	78	
Laho	UT	QF	3	
Milford 2	UT	QF	3	
Milford Flat	UT	QF	3	
Pavant	UT	QF	48	
Pavant II	UT	QF	49	
Quichapa I	UT	QF	3	
Quichapa II	UT	QF	3	
Quichapa III	UT	QF	3	
Red Hill	UT	QF	78	
South Milford	UT	QF	3	
SunE1	UT	QF	3	
SunE2	UT	QF	3	
SunE3	UT	QF	3	
Three Peaks	UT	QF	78	
Woodline	UT	QF	8	
Sunnyside Solar*	WA	QF	5	
Sage I	WY	QF	20	
Sage II	WY	QF	20	
Sage III	WY	QF	17	
Sweetwater	WY	QF	79	
Green River*	UT	PPA	400	200
Faraday*	UT	PPA	525	150
TOTAL – Purchased Solar			**3,278**	**350**

* New projected added in 2023 IRP

Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp also has a power purchase agreement with the 20 MW Soda Lake geothermal project located in Nevada, which became operational in November 2019.

Biomass/Biogas

PacifiCorp has biomass/biogas agreements with 12 projects totaling approximately 80 MW of nameplate capacity.

Storage

PacifiCorp has two existing or committed battery storage projects totaling approximately 3 MW of nameplate capacity, as shown in Table 6.7.

Table 6.7 – Storage Resources

Power Purchase Agreements / Exchanges	State	Technology	Capacity (MW)
Panguitch*	UT	Battery	1
Oregon Institute of Technology (OIT)*	OR	Battery	2
TOTAL – Purchased Battery			**3**

*New projects added in 2023 IRP

Renewables Private Generation

Table 6.8 provides a breakdown of private generation capacity and customer counts from data collected as of March 12, 2023. For forecasted growth in Private Generation, please refer to Volume II, Appendix L (Private Generation Study).

Table 6.8 – Private Generation Customers and Capacity

Fuel	Solar	Wind	Gas[1/]	Hydro	Mixed[2/]
Nameplate (kW)	772,160	847	784	965	1,233
Capacity (percentage of total)	99.51%	0.11%	0.10%	0.12%	0.16%
Number of customers	86,449	192	3	21	63
Customer (percentage of total)	99.68%	0.22%	0.00%	0.02%	0.07%

[1/] **Gas includes: biofuel, waste gas, and fuel cells**

[2/] **Mixed includes projects with multiple technologies, one project is solar and biogas and the others are solar and wind**

Hydroelectric Generation

PacifiCorp owns or purchases nearly 1,400 MW of hydroelectric generation capacity. In addition to being non-emitting generation sources hydro resources provide various operational benefits that can include flexible generation, spinning reserves, and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity available from hydroelectric plants is dependent upon a number of factors, including the water content of snowpack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control.

Table 6.9 provides the capacity for each of PacifiCorp's owned hydroelectric generation facilities.

Table 6.9 – PacifiCorp Hydroelectric Generation Facilities

Plant	River System	State	Capacity (MW)
East			
Cutler	Bear	UT	29
Grace	Bear	UT	33
Oneida	Bear	UT	27.9
Soda	Bear	UT	14
Small East [1/]	Other	UT	20.5
West			
Bend	Other	OR	1
Big Fork	Other	MT	4.6
Swift 1	Lewis	WA	263.6
Yale	Lewis	WA	163.6
Merwin	Lewis	WA	151
Clearwater 1	N. Umpqua	OR	17.9
Clearwater 2	N. Umpqua	OR	31
Fish Creek	N. Umpqua	OR	10.4
Lemolo 1	N. Umpqua	OR	32
Lemolo 2	N. Umpqua	OR	38.5
Slide Creek	N. Umpqua	OR	18
Soda Springs	N. Umpqua	OR	11.6
Toketee	N. Umpqua	OR	45
Eagle Point	Rogue	OR	2.8
Prospect 1	Rogue	OR	4.6
Prospect 2	Rogue	OR	36
Prospect 3	Rogue	OR	7.7
Prospect 4	Rogue	OR	0.9
Fall Creek	Other	OR	2
Wallowa Falls	Other	OR	1.1
Owned Hydroelectric			**968**
QF	Various	CA	9.4
QF	Various	ID	22.7
QF	Various	OR	40.0

QF	Various	UT	2.2
QF	Various	WA	2.9
Swift 2 [2/]	Lewis	WA	51.8
Copco 1	Klamath [3/]	OR/CA	28
Copco 2	Klamath [3/]	OR/CA	34
Iron Gate	Klamath [3/]	OR/CA	18.8
JC Boyle	Klamath [3/]	OR/CA	83
Mid-Columbia	Columbia	WA	170
Hydroelectric Contracts			**463**
TOTAL – Hydroelectric			**1431**

[1/] Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Veyo, Sand Cove, Viva Naughton, and Gunlock.
[2/] Cowlitz County PUD owns Swift No. 2, and is operated in coordination with other Lewis River projects by PacifiCorp.
[3/] The Klamath projects are being operated by PacifiCorp under an agreement with the Klamath River Renewal Corporation (KRRC) until the KRRC commences removal activities, expected in 2024.

Demand-Side Management/Distributed Generation

For resource planning purposes, PacifiCorp classifies demand-side management (DSM) resources into four categories. These resources are captured through programmatic efforts that promote efficient electricity use through various intervention strategies, aimed at changing energy use during peak periods (load control), timing (price response and load shifting), intensity (energy efficiency), or behaviors (education and information). The four categories include:

- **Demand Response—Resources from fully dispatchable or scheduled firm capacity product offerings/programs:** Demand Response programs are those for which capacity savings occur because of active company control or advanced scheduling. Once customers agree to participate in these programs, the timing and persistence of the load reduction is involuntary on their part within the agreed upon limits and parameters of the program. Program examples include residential and small commercial central air conditioner load control programs that are dispatchable, and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design or event noticing requirements). Savings are typically only sustained for the duration of the event and there may also be return energy associated with the program.

- **Energy Efficiency—Resources from non-dispatchable, firm energy and capacity product offerings/programs:** Energy Efficiency programs are energy and related capacity savings which are achieved through facilitation of technological advancements in equipment, appliances, structures, or repeatable and predictable voluntary actions on a customer's part to manage the energy use at their business or home. These programs generally provide financial incentives or services to customers to improve the efficiency of existing or new residential or commercial buildings through: (1) the installation of more efficient equipment, such as lighting, motors, air conditioners, or appliances; (2) increasing building efficiency, such as improved insulation levels or windows; or (3) behavioral modifications, such as strategic energy management efforts at business or home energy reports for residential customers. The savings are considered firm over the life of the improvement or customer action.

- **Price Response and Load Shifting—Resources from price-responsive energy and capacity product offerings/programs:** Price response and load shifting programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. As a result of their voluntary nature, participation tends to be low and savings are less predictable, making these resources less suitable to incorporate into resource planning, at least until their size and customer behavior profile provide sufficient information needed to model and plan for a reliable and predictable impact. The impacts of these resources may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs. Savings are typically only sustained for the duration of the incentive offering and, in many cases, loads tend to be shifted rather than being avoided.

- **Education and Information—Non-incented behavioral-based savings achieved through broad energy education and communication efforts:** Education and Information programs promote reductions in energy or capacity usage through broad-based energy education and communication efforts. The program objectives are to help customers better understand how to manage their energy usage through no-cost actions such as conservative thermostat settings and turning off appliances, equipment, and lights when not in use. These programs are also used to increase customer awareness of additional actions they might take to save energy and the service and financial tools available to assist them. These programs help foster an understanding and appreciation of why utilities seek customer participation in other programs. Similar to price response and load shifting resources, the impacts of these programs may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include company brochures with energy savings tips, customer newsletters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs.

PacifiCorp has been operating successful DSM programs since the late 1970s. Over time, PacifiCorp's DSM acquisition has expanded to new heights in terms of investment level, state presence, breadth of DSM resources pursued and resource planning considerations. Work continues on the expansion of cost-effective program portfolios and savings opportunities in all states while at the same time adapting programs and measure baselines to reflect the impacts of advancing state and federal energy codes and standards. In Oregon, PacifiCorp continues to work closely with the Energy Trust of Oregon to help identify additional resource opportunities, improve delivery and communication coordination, ensure adequate funding, and provide company support in pursuit of DSM resource targets.

Table 6.10 summarizes PacifiCorp's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental energy efficiency is determined as an outcome of resource portfolio modeling and is characterized as a new resource in the preferred portfolio, existing energy efficiency in Table 6.10 is shown as having zero MW.[1] For a summary of current DSM program offerings in each state, refer to Volume II, Appendix D (Demand-Side Management Resources).

Table 6.10 – Existing DSM Resource Summary

Program	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2023-2042 Period
Demand Response	Residential/small commercial air conditioner load control	135 MW summer	Yes.
	Irrigation load management	205210 MW summer	Yes.
	Interruptible contracts	239 MW summer	Yes.
	WattSmart Batteries	11 MW summer	Yes.
	WattSmart Business[1/]	30 MW summer	Yes.
Energy Efficiency	PacifiCorp and Energy Trust of Oregon programs	0 MW[2]	No. Energy efficiency programs are modeled as resource options in the portfolio development process and included in the preferred portfolio.
Price Response and Load Shifting	Time-based pricing	Energy and capacity impacts are not available/measured	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	Energy and capacity impacts are not available/measured	No. Historical savings from customer response to pricing structure is reflected in load forecast.
Education and Information	Energy education	Energy and capacity impacts are not available/measured	No. Historical savings from customer participation are reflected in the load forecast.

[1/] C&I curtailment programs have been recently approved in OR, WA, ID, and UT. Totals represent the existing resources at the time of modeling which were less than currently approved and effective programs in March 2023.
[2/] Due to the timing of the 2023 IRP load forecast, there is a small amount (100 MW) of existing Energy Efficiency in Table 6.12 (System Capacity Loads and Resources without Resource Additions).

Private Generation Forecast

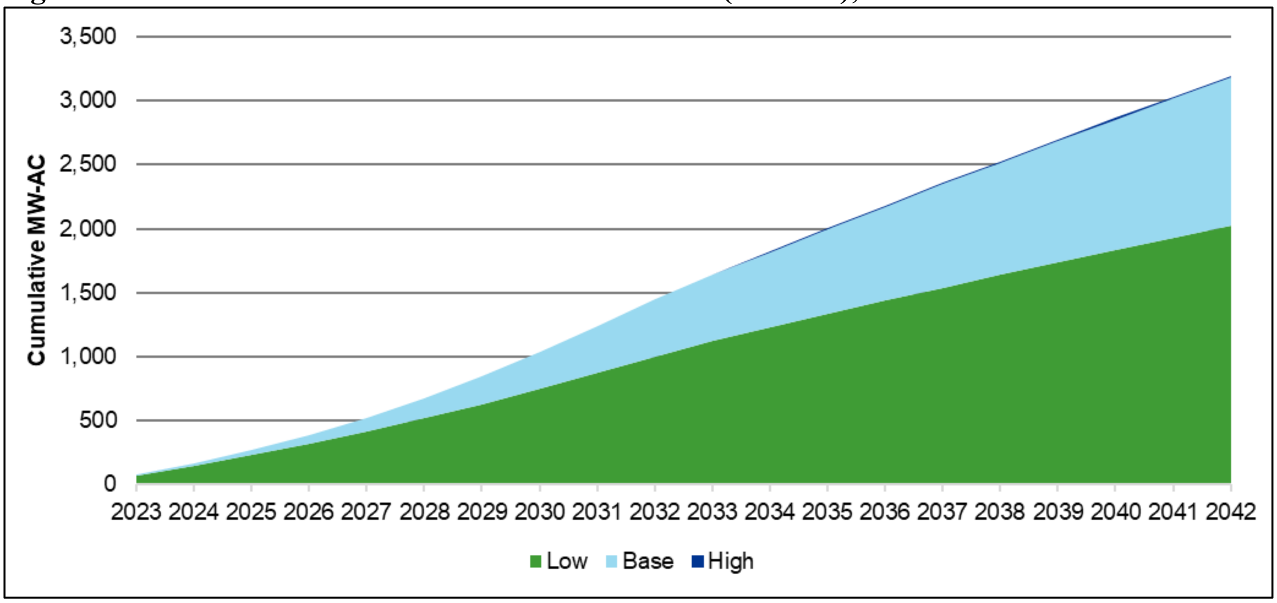
For the 2023 IRP, PacifiCorp contracted with DNV to update the assessment of private generation (PG) penetration performed for the 2023 IRP with new market, policy, and incentive developments. The study provided a forecast of adoption of behind-the-meter (BTM) customer generation resources in each of the six states served by PacifiCorp. Specific technologies studied included solar photovoltaic, photovoltaic solar coupled with battery storage, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines.

DNV estimates approximately 3.18 gigawatts (GW) of PG capacity will be installed in PacifiCorp's territory from 2023-2042 in the base case scenario. As shown in Figure 6.1, the low

[1] The historical effects of previous Energy Efficiency savings are captured in the load forecast before the modeling for new Energy Efficiency.

and high scenarios project a cumulative installed capacity of 2.03 GW and 3.20 GW by 2042, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions. The Inflation Reduction Act of 2022 (IRA) extends tax credits for private generation that creates favorable economics for adoption and is incorporated into each case. While the high case included lower technology cost estimates and higher retail electricity rates, these had very little impact on adoption, and the result was only slightly higher than the base case. The DNV study identifies expected levels of customer-sited private generation, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes and informs customer cited demand response battery potential for the conservation potential assessment (CPA).

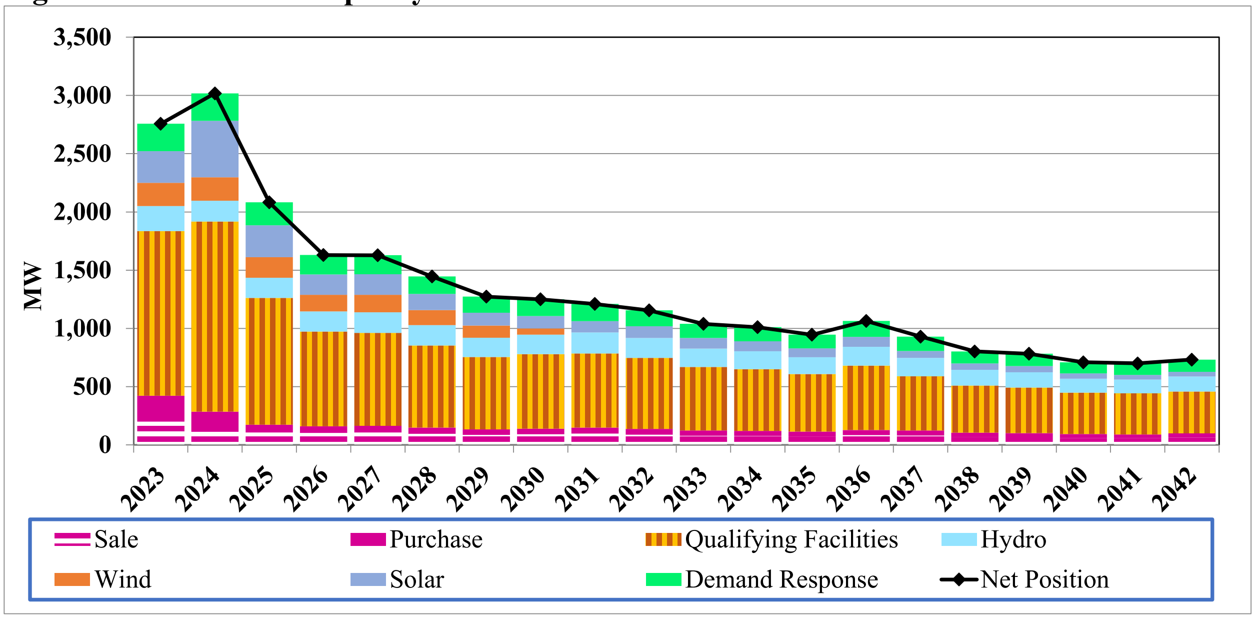
Figure 6.1 – Private Generation Market Penetration (MWAC), 2023-2042



Power-Purchase Agreements

PacifiCorp obtains the remainder of its capacity and energy requirements through long-term firm contracts, short-term firm contracts, and spot market purchases. Figure 6.2 presents the contract capacity in place for 2023 through 2043. As shown, major capacity reductions in solar purchases, wind purchases, and QF contracts occur. For planning purposes, PacifiCorp assumes interruptible load contracts and demand response are extended through the end of the IRP study period. All contracts are shown at their peak capacity contribution levels.

Figure 6.2 – Contract Capacity in the 2021 IRP Summer Load and Resource Balance



Capacity Load and Resource Balance

Capacity Balance Overview

The purpose of the load and resource balance is to compare annual obligations with the annual capability of PacifiCorp's existing resources, without new generating resource additions.

The capacity balance compares generating capability to load obligations across both summer and winter. In the past, the coincident peak load hour was almost always the hour with the lowest margin, because the available resource output was comparable in the peak load hour and in other hours. With the significant penetration of solar resources in PacifiCorp's portfolio, the hour with the lowest margin is no longer readily identifiable from load alone, as solar resources have high availability during the peak load hour but no availability a few hours later when loads are slightly lower. Wind, storage, hydro, and other resources further complicate the calculation. Considering this, for the 2023 IRP, PacifiCorp evaluated the balance of generating capability and load obligations not just during the coincident peak load hour, but across all hours, to identify the winter and summer hours in each year with the lowest margin as a percentage of load. Under this method, the reported planning reserve margin is necessarily met in the coincident peak load hour, but the hour with the lowest margin generally coincides with a period of relatively high load and relatively low renewable resource output.

For reporting purposes, the capacity balance summarized in this chapter is developed by first reducing the hourly system load by hourly private generation projections to determine the net system coincident peak load for each of the first ten years (2023-2032) of the planning horizon. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are further netted from the peak load forecast to compute the annual peak-hour obligation. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. The annual resource deficit or surplus is then computed by multiplying the obligation by the planning reserve margin (13% for the 2023 IRP) and then subtracting the result from existing resources. This view is presented both without and with uncommitted Market purchases.

The economics of adding resources to the system to meet both capacity and energy needs are addressed during the resource portfolio development process described in Chapter 8 (Modeling and Portfolio Evaluation Approach).

Load and Resource Balance Components

The main component categories consist of the following: resources, obligation, reserves, position, and available market purchases.

Under the calculations, there are negative values in the table in both the resource and obligation sections. This is consistent with how resource categories are represented in portfolio modeling. The resource categories include resources by type—thermal, hydroelectric, renewable, QFs, purchases, and sales. Categories in the obligation section include load (net of private generation), existing demand response, existing energy efficiency, and new energy efficiency from the preferred portfolio.

Existing Resources
A description of the resource categories follows:

Resources without duration limits
For the purpose of reporting the capacity contribution resources without duration limits, including thermal, wind, solar, and other small generators, PacifiCorp first calculated the availability of each resource type during the top five percent of net load hours in each season (calculated as PacifiCorp's load less the wind and solar generation in its portfolio). For the purpose of reporting load in the load and resource balance, the single highest load hour is used, and a planning reserve margin of 13% is added. Resources whose is output higher in the top five percent load hours than in the top five percent net load hours are then allocated additional capacity value for their role in meeting peak requirements. It should be noted that while allocation of capacity among resources as described in this section is helpful for presenting a load and resource balance, the allocation to specific resources has no bearing on the reliability or economics of the preferred portfolio, which reflects the coordinated dispatch of all available resources in every hour of the year. The economics of resource additions are more closely aligned with marginal or "last-in" capacity contribution estimates, which are generally lower for resources whose output is positively correlated with other resources already present in the portfolio. For a discussion of marginal capacity contribution methodologies, please refer to PacifiCorp's 2021 IRP, specifically Volume II, Appendix K (Capacity Contribution).

Resources with duration limits
Certain resource types have duration limits, such that while they could be called upon in any given hour, they cannot be called upon continuously for more than specified duration. Such resources include energy storage, such as batteries or pumped hydro, as well as demand response programs and contracts, which generally have limits on consecutive hours, hours per day, and/or hours per year. As a result, while these resources are available in every hour, they are limited in how often they can be called upon for energy. However, reliable system operation also requires resources that can be deployed at short notice to address unexpected events that occur relatively infrequently, such as a generator outage, increase in load, or decrease in wind and solar output. These operating

reserve requirements are part of the load and resource balance, and because they do not require frequent energy dispatch, duration-limited resources are assumed to be able to provide operating reserves continuously. Once operating reserve needs are fulfilled in a given hour, energy limited resources would need to deploy energy to make additional contributions to serving load. This incremental energy is assumed to be deployed in the hours with the highest shortfalls, but is capped for each day at the lesser of the total duration of energy-limited resources (in MWh) and available excess generation capacity in hours where resources exceed the capacity requirement. This represents the need to charge batteries, for example, which represent the vast majority of the energy-limited resources through the study horizon. After summing the operating reserve and energy contributions of duration-limited resources, their capacity contribution as a class is calculated based on the net output in the top five percent net load hours, as described above. This total contribution is then allocated back to individual resources based on their duration capability, with shorter duration resources receiving a lower contribution. As their share of the system capacity need increases, longer duration resources are needed to provide the equivalent capacity and reliability benefits, and the contribution from shorter duration resources is reduced.

Sales

Contracts for the sale of firm capacity and energy are treated the same as all other resources, except that they have a negative capacity value.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less private generation, existing energy efficiency, new energy efficiency from the preferred portfolio, existing demand response and interruptible contracts. The following are descriptions of each of these components:

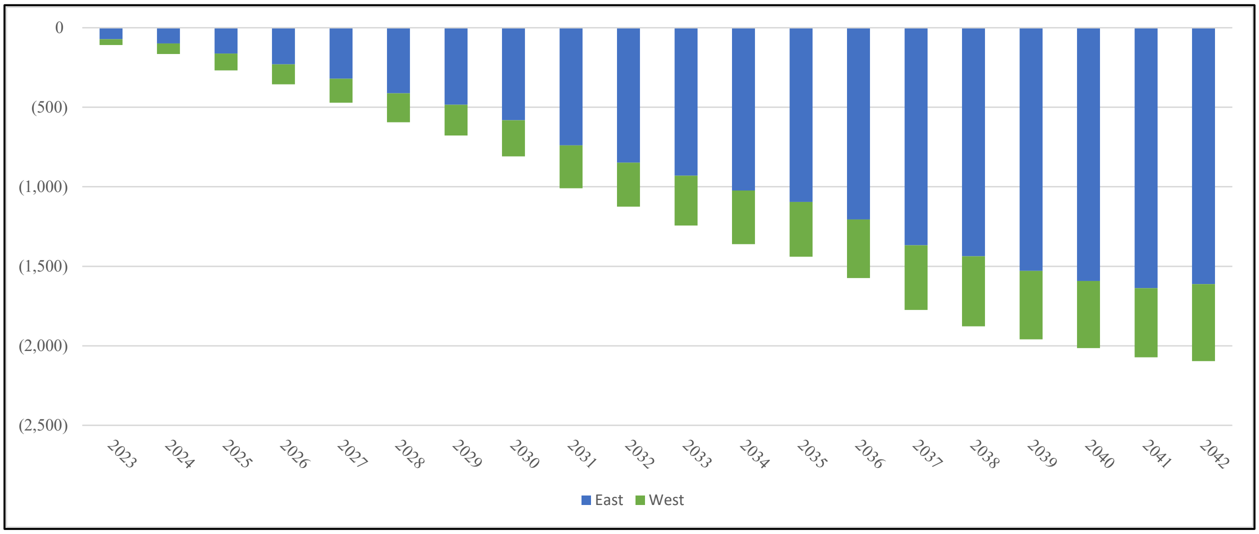
Load Net of Private Generation

The largest component of the obligation is retail load. In the 2023 IRP, the hourly retail load at a location is first reduced by hourly private generation at the same location. The system coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year and season. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks.

Energy Efficiency

An adjustment is made to load to remove the projected embedded energy efficiency as a reduction to load. Due to timing issues with the vintage of the load forecast, there is a level of 2022 energy efficiency that is not incorporated in the forecast. The 2022 energy efficiency forecast (100 MW) has been accounted for by adding an existing energy efficiency resource in the load and resource balance. The energy efficiency line also includes the energy efficiency selected in the 2023 IRP preferred portfolio. Figure 6.3 shows the energy efficiency for the east and west control areas in the 2023 IRP preferred portfolio.

Figure 6.3 – Energy Efficiency Peak Contribution in Summer Capacity Load and Resource Balance (reduction to load, in MW)



Demand Response

Existing demand response program capacity is categorized as a reduction to peak load. Also included in the demand response category are interruptible contracts. PacifiCorp has had a number of interruptible contracts with large load customers for many years. These contracts are a key aspect of the retail service provided to the associated customers, and absent these contracts their demand would likely be different from that included in the load forecast. To maintain an alignment with the load forecast, these contracts are assumed to continue indefinitely under their current structure.

Planning Reserve Margin

Planning reserve margin (PRM) represents an incremental capacity requirement, applied as an increase to the obligation to ensure that there will be sufficient capacity available on the system to manage uncertain events (i.e., weather, outages) and known requirements (i.e., operating reserves).

Position

The position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources.

Capacity Balance Determination

Methodology

The capacity balance is developed by first determining the system coincident peak load for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system summer and winter peak periods, as applicable, and summed as follows:

> **Existing Resources** = Thermal + Hydro + Renewable + Storage + Firm Purchases + Qualifying Facilities – Firm Sales

The peak load, private generation, demand response, existing energy efficiency, and new energy efficiency (from the preferred portfolio) are netted together for each of the annual system summer and winter peaks, as applicable, to compute the annual peak obligation:

> **Obligation** = Load – Private Generation – Demand Response – New and Existing Energy Efficiency

The level of reserves to be added to the obligation is then calculated. This is accomplished by taking the net system obligation calculated above multiplied by the 13 percent PRM adopted for the 2023 IRP. The formula for this calculation is:

> **Planning Reserves** = Obligation x PRM

Finally, the annual capacity position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources, including available Market purchases, as shown in the following formula:

> **Capacity Position** = (Existing Resources + Available Market purchases) – (Obligation + Planning Reserves)

Capacity Balance Results

Table 6.11 and Table 6.12 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target PRM of 13 percent to calculate the planning reserve amount. Balances for PacifiCorp's system as well as the east and west control areas are shown. While east and west control area balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis. Also note that new QF wind and solar projects listed earlier in the chapter are reported under the QF line item rather than the renewables line item.

Table 6.11 -- Summer Peak – System Capacity Loads and Resources without Resource Additions

East	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Thermal	5,271	5,056	4,873	4,893	4,857	4,523	4,191	4,332	4,454	3,886
Hydroelectric	87	70	65	65	65	62	60	62	64	59
Renewable	771	648	541	460	480	484	405	412	388	376
Storage	1	1	1	1	1	1	1	1	1	1
Purchase	104	100	31	27	26	23	22	22	23	21
Qualifying Facilities	834	983	576	375	358	329	285	296	275	265
Sale	(21)	0	0	0	0	0	0	0	0	0
East Existing Resources	**7,047**	**6,857**	**6,087**	**5,821**	**5,786**	**5,422**	**4,963**	**5,125**	**5,205**	**4,608**
Load	7,485	7,720	7,889	7,886	8,074	8,406	8,376	8,516	8,731	8,849
Private Generation	(83)	(118)	(157)	(200)	(248)	(301)	(263)	(311)	(364)	(418)
Existing - Demand Response	(159)	(166)	(132)	(112)	(107)	(98)	(93)	(97)	(96)	(87)
Existing - Energy Efficiency	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
New Energy Efficiency	(71)	(99)	(162)	(231)	(321)	(412)	(484)	(581)	(739)	(848)
East Total obligation	**7,101**	**7,267**	**7,368**	**7,272**	**7,328**	**7,525**	**7,466**	**7,457**	**7,461**	**7,426**
Planning Reserve Margin (13%)	923	945	958	945	953	978	971	969	970	965
East Obligation + Reserves	8,024	8,212	8,326	8,218	8,281	8,503	8,437	8,427	8,431	8,391
East Position	(977)	(1,355)	(2,239)	(2,397)	(2,494)	(3,081)	(3,473)	(3,302)	(3,227)	(3,783)
Available Market Purchases	325	325	325	325	325	0	0	0	0	0
West										
Thermal	631	603	575	585	579	560	542	468	481	446
Hydroelectric	604	535	515	525	520	502	486	503	517	480
Renewable	120	118	91	87	85	84	80	82	83	70
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	255	291	200	150	139	128	110	115	111	105
Sale	(75)	(54)	(51)	(50)	(50)	(48)	(43)	(46)	(47)	(42)
West Existing Resources	**1,536**	**1,493**	**1,331**	**1,297**	**1,274**	**1,226**	**1,176**	**1,123**	**1,148**	**1,061**
Load	3,656	3,863	4,067	4,140	4,309	4,481	4,655	4,711	4,873	4,913
Private Generation	(25)	(37)	(51)	(67)	(83)	(101)	(85)	(100)	(117)	(135)
Existing - Demand Response	(8)	(7)	(7)	(6)	(6)	(5)	(5)	(5)	(5)	(5)
Existing - Energy Efficiency	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)
New Energy Efficiency	(37)	(66)	(107)	(125)	(150)	(182)	(193)	(228)	(269)	(277)
West Total obligation	**3,556**	**3,722**	**3,871**	**3,911**	**4,039**	**4,162**	**4,342**	**4,347**	**4,451**	**4,466**
Planning Reserve Margin (13%)	462	484	503	508	525	541	564	565	579	581
West Obligation + Reserves	4,018	4,205	4,374	4,420	4,564	4,703	4,906	4,912	5,030	5,047
West Position	(2,482)	(2,712)	(3,044)	(3,122)	(3,290)	(3,476)	(3,730)	(3,789)	(3,882)	(3,986)
Available Market Purchases	3,000	3,000	3,000	3,000	3,000	500	500	500	500	500
System										
Total Resources	8,584	8,351	7,418	7,118	7,060	6,648	6,139	6,248	6,352	5,668
Obligation	10,657	10,989	11,239	11,184	11,367	11,686	11,808	11,804	11,912	11,892
Planning Reserves (13%)	1,385	1,429	1,461	1,454	1,478	1,519	1,535	1,535	1,549	1,546
Obligation + Reserves	12,043	12,417	12,700	12,638	12,845	13,206	13,343	13,339	13,461	13,438
System Position	(3,459)	(4,066)	(5,283)	(5,519)	(5,785)	(6,557)	(7,204)	(7,091)	(7,109)	(7,769)
Available Market Purchases	3,325	3,325	3,325	3,325	3,325	500	500	500	500	500
Uncommitted FOTs to meet remaining Need	3,459	4,066	5,283	3,325	3,325	500	500	500	500	500
Net Surplus/(Deficit)	0	0	0	(2,194)	(2,460)	(6,057)	(6,704)	(6,591)	(6,609)	(7,269)

Table 6.11 (cont.) – Summer Peak System Capacity Loads and Resources without Resource Additions

East	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	2,555	2,347	2,338	2,759	2,198	1,100	1,111	710	748	827
Hydroelectric	53	53	52	62	57	47	47	41	43	47
Renewable	364	356	332	419	346	300	305	261	257	263
Storage	1	0	0	0	0	0	0	0	0	0
Purchase	19	19	19	22	20	16	16	14	15	17
Qualifying Facilities	241	241	225	261	192	173	170	151	152	154
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**3,232**	**3,017**	**2,966**	**3,523**	**2,812**	**1,636**	**1,649**	**1,178**	**1,215**	**1,308**
Load	8,981	9,134	9,301	9,541	9,680	9,844	9,987	10,160	10,340	10,565
Private Generation	(472)	(522)	(571)	(620)	(668)	(716)	(763)	(808)	(856)	(902)
Existing - Demand Response	(76)	(78)	(78)	(94)	(80)	(66)	(68)	(61)	(65)	(68)
Existing - Energy Efficiency	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
New Energy Efficiency	(931)	(1,023)	(1,096)	(1,205)	(1,368)	(1,437)	(1,529)	(1,592)	(1,638)	(1,612)
East Total obligation	**7,432**	**7,442**	**7,486**	**7,553**	**7,494**	**7,556**	**7,558**	**7,630**	**7,712**	**7,913**
Planning Reserve Margin (13%)	966	967	973	982	974	982	983	992	1,003	1,029
East Obligation + Reserves	8,399	8,409	8,459	8,535	8,468	8,538	8,541	8,622	8,715	8,942
East Position	(5,166)	(5,392)	(5,493)	(5,013)	(5,656)	(6,902)	(6,891)	(7,443)	(7,500)	(7,633)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0
West										
Thermal	397	396	395	466	430	234	237	206	217	240
Hydroelectric	426	426	424	501	461	374	379	329	346	383
Renewable	67	68	64	80	65	56	62	54	56	56
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	96	97	92	111	90	79	77	68	69	71
Sale	(38)	(38)	(37)	(43)	(40)	(34)	(34)	(29)	(30)	(33)
West Existing Resources	**950**	**949**	**939**	**1,115**	**1,007**	**711**	**722**	**629**	**658**	**716**
Load	4,992	5,070	5,147	5,230	5,320	5,400	5,481	5,575	5,667	5,807
Private Generation	(153)	(169)	(185)	(199)	(214)	(228)	(242)	(256)	(270)	(283)
Existing - Demand Response	(4)	(4)	(4)	(5)	(4)	(4)	(4)	(3)	(3)	(4)
Existing - Energy Efficiency	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)
New Energy Efficiency	(313)	(337)	(343)	(369)	(406)	(440)	(429)	(423)	(434)	(485)
West Total obligation	**4,491**	**4,529**	**4,584**	**4,627**	**4,665**	**4,697**	**4,775**	**4,863**	**4,929**	**5,005**
Planning Reserve Margin (13%)	584	589	596	601	606	611	621	632	641	651
East Obligation + Reserves	271	252	252	232	201	171	192	209	206	166
East Position	679	697	686	883	806	540	530	420	451	550
Available Market Purchases	500	500	500	500	500	500	500	500	500	500
System										
Total Resources	4,182	3,965	3,905	4,638	3,819	2,346	2,371	1,808	1,873	2,025
Obligation	11,924	11,970	12,070	12,180	12,159	12,253	12,333	12,493	12,641	12,918
Planning Reserves (13%)	1,550	1,556	1,569	1,583	1,581	1,593	1,603	1,624	1,643	1,679
Obligation + Reserves	13,474	13,526	13,640	13,763	13,739	13,845	13,937	14,117	14,285	14,598
System Position	(9,291)	(9,561)	(9,734)	(9,126)	(9,920)	(11,499)	(11,566)	(12,309)	(12,412)	(12,573)
Available Market Purchases	500	500	500	500	500	500	500	500	500	500
Uncommitted FOTs to meet remaining Need	500	500	500	500	500	500	500	500	500	500
Net Surplus/(Deficit)	(8,791)	(9,061)	(9,234)	(8,626)	(9,420)	(10,999)	(11,066)	(11,809)	(11,912)	(12,073)

Table 6.12 – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Thermal	5,894	5,321	5,478	5,151	5,547	5,383	4,804	4,613	5,407	4,786
Hydroelectric	71	57	56	54	57	58	54	54	61	58
Renewable	790	999	877	827	921	682	568	585	604	618
Storage	1	1	1	1	1	1	1	1	1	1
Purchase	116	70	34	28	28	27	24	24	27	25
Qualifying Facilities	243	274	234	217	233	183	166	169	182	179
Sale	(23)	0	0	0	0	0	0	0	0	0
East Existing Resources	**7,093**	**6,721**	**6,679**	**6,279**	**6,786**	**6,333**	**5,617**	**5,445**	**6,280**	**5,667**
Load	5,833	5,890	6,032	6,039	6,253	6,426	6,496	6,586	6,680	6,739
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(68)	(63)	(59)	(48)	(49)	(46)	(41)	(41)	(47)	(44)
Existing - Energy Efficiency	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)
New Energy Efficiency	(41)	(80)	(150)	(180)	(238)	(301)	(346)	(416)	(544)	(598)
East Total obligation	**5,684**	**5,707**	**5,783**	**5,771**	**5,926**	**6,038**	**6,069**	**6,089**	**6,048**	**6,056**
Planning Reserve Margin (13%)	739	742	752	750	770	785	789	792	786	787
East Obligation + Reserves	6,423	6,449	6,535	6,521	6,696	6,823	6,858	6,880	6,835	6,843
East Position	670	272	144	(242)	90	(490)	(1,241)	(1,435)	(554)	(1,176)
Available Market Purchases	325	325	325	325	325	300	300	300	300	300
West										
Thermal	745	707	687	672	701	698	655	563	630	606
Hydroelectric	749	692	655	642	670	680	637	637	714	684
Renewable	89	100	91	83	85	72	66	76	83	75
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	81	84	79	72	69	67	60	60	67	61
Sale	(80)	(58)	(55)	(53)	(56)	(48)	(43)	(45)	(50)	(46)
West Existing Resources	**1,586**	**1,526**	**1,459**	**1,417**	**1,470**	**1,471**	**1,377**	**1,292**	**1,445**	**1,381**
Load	3,485	3,738	3,911	3,993	4,148	4,336	4,397	4,415	4,530	4,562
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	0	0	0	(0)	0	0	0	(0)	(0)	(0)
Existing - Energy Efficiency	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
New Energy Efficiency	(35)	(66)	(98)	(168)	(214)	(244)	(310)	(331)	(360)	(399)
West Total obligation	**3,421**	**3,643**	**3,783**	**3,795**	**3,905**	**4,062**	**4,057**	**4,054**	**4,141**	**4,133**
Planning Reserve Margin (13%)	445	474	492	493	508	528	527	527	538	537
West Obligation + Reserves	409	407	4,274	4,289	4,413	4,591	4,585	4,581	4,679	4,670
West Position	1,176	1,119	(2,815)	(2,872)	(2,942)	(3,120)	(3,208)	(3,289)	(3,234)	(3,289)
Available Market Purchases	3,000	3,000	3,000	3,000	3,000	700	700	700	700	700
System										
Total Resources	8,678	8,248	8,138	7,696	8,257	7,804	6,994	6,737	7,726	7,048
Obligation	9,104	9,350	9,566	9,566	9,831	10,101	10,126	10,143	10,190	10,189
Planning Reserves (13%)	1,184	1,215	1,244	1,244	1,278	1,313	1,316	1,319	1,325	1,325
Obligation + Reserves	10,288	10,565	10,809	10,810	11,109	11,414	11,442	11,461	11,514	11,513
System Position	(1,609)	(2,318)	(2,671)	(3,114)	(2,852)	(3,610)	(4,448)	(4,724)	(3,788)	(4,466)
Available Market Purchases	3,325	3,325	3,325	3,325	3,325	1,000	1,000	1,000	1,000	1,000
Uncommitted FOTs to meet remaining Need	1,609	2,318	2,671	3,114	2,852	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	0	0	0	0	0	(2,610)	(3,448)	(3,724)	(2,788)	(3,466)

Table 6.12 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	3,451	3,007	2,712	2,702	2,471	1,398	1,307	934	876	941
Hydroelectric	56	52	47	49	52	46	44	41	39	42
Renewable	501	491	466	535	507	397	358	364	327	337
Storage	1	0	0	0	0	0	0	0	0	0
Purchase	24	22	20	21	22	20	19	18	17	18
Qualifying Facilities	151	138	127	129	130	107	102	94	91	92
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**4,183**	**3,711**	**3,373**	**3,438**	**3,182**	**1,968**	**1,829**	**1,452**	**1,349**	**1,429**
Load	6,882	6,990	7,093	7,171	7,319	7,448	7,592	7,711	7,816	7,969
Private Generation	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Existing - Demand Response	(42)	(39)	(35)	(37)	(39)	(34)	(34)	(32)	(30)	(32)
Existing - Energy Efficiency	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)
New Energy Efficiency	(669)	(729)	(770)	(827)	(951)	(986)	(1,025)	(1,090)	(1,057)	(1,144)
East Total obligation	**6,130**	**6,181**	**6,246**	**6,266**	**6,289**	**6,387**	**6,492**	**6,549**	**6,688**	**6,751**
Planning Reserve Margin (13%)	797	804	812	815	818	830	844	851	869	878
East Obligation + Reserves	6,927	6,985	7,059	7,080	7,106	7,217	7,336	7,400	7,558	7,629
East Position	(2,744)	(3,274)	(3,685)	(3,643)	(3,924)	(5,249)	(5,507)	(5,948)	(6,209)	(6,200)
Available Market Purchases	300	300	300	300	300	300	300	300	300	300
West										
Thermal	575	541	490	514	522	325	307	291	271	291
Hydroelectric	657	616	556	581	614	541	517	484	451	485
Renewable	59	61	54	64	65	51	46	46	46	50
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	57	55	50	52	53	46	44	42	40	42
Sale	(41)	(39)	(36)	(40)	(39)	(34)	(30)	(30)	(27)	(29)
West Existing Resources	**1,308**	**1,234**	**1,116**	**1,172**	**1,216**	**929**	**885**	**834**	**782**	**841**
Load	4,607	4,654	4,702	4,772	4,830	4,878	4,943	4,995	5,054	5,132
Private Generation	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Existing - Demand Response	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Energy Efficiency	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
New Energy Efficiency	(426)	(469)	(506)	(581)	(597)	(634)	(663)	(648)	(719)	(671)
West Total obligation	**4,151**	**4,155**	**4,166**	**4,161**	**4,202**	**4,214**	**4,249**	**4,317**	**4,304**	**4,430**
Planning Reserve Margin (13%)	540	540	542	541	546	548	552	561	560	576
East Obligation + Reserves	113	71	35	(40)	(51)	(86)	(110)	(87)	(159)	(95)
East Position	1,195	1,163	1,081	1,212	1,267	1,015	995	920	942	936
Available Market Purchases	700	700	700	700	700	700	700	700	700	700
System										
Total Resources	5,492	4,945	4,489	4,610	4,398	2,897	2,714	2,285	2,131	2,270
Obligation	10,281	10,336	10,412	10,427	10,491	10,601	10,741	10,865	10,992	11,181
Planning Reserves (13%)	1,337	1,344	1,354	1,355	1,364	1,378	1,396	1,413	1,429	1,454
Obligation + Reserves	11,617	11,680	11,766	11,782	11,855	11,979	12,138	12,278	12,422	12,635
System Position	(6,126)	(6,735)	(7,277)	(7,173)	(7,457)	(9,082)	(9,424)	(9,992)	(10,291)	(10,364)
Available Market Purchases	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Uncommitted FOTs to meet remaining Need	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	(5,126)	(5,735)	(6,277)	(6,173)	(6,457)	(8,082)	(8,424)	(8,992)	(9,291)	(9,364)

Figure 6.4 through Figure 6.7 are graphic representations of the above tables for annual capacity position for the summer system, winter system, east control area, and west control area. Also shown in the system capacity position graph are available Market purchases, which can be used

to meet capacity needs. The market availability assumptions used for portfolio modeling are discussed further in Chapter 7 (Resource Options).

Figure 6.4 – Summer System Capacity Position Trend

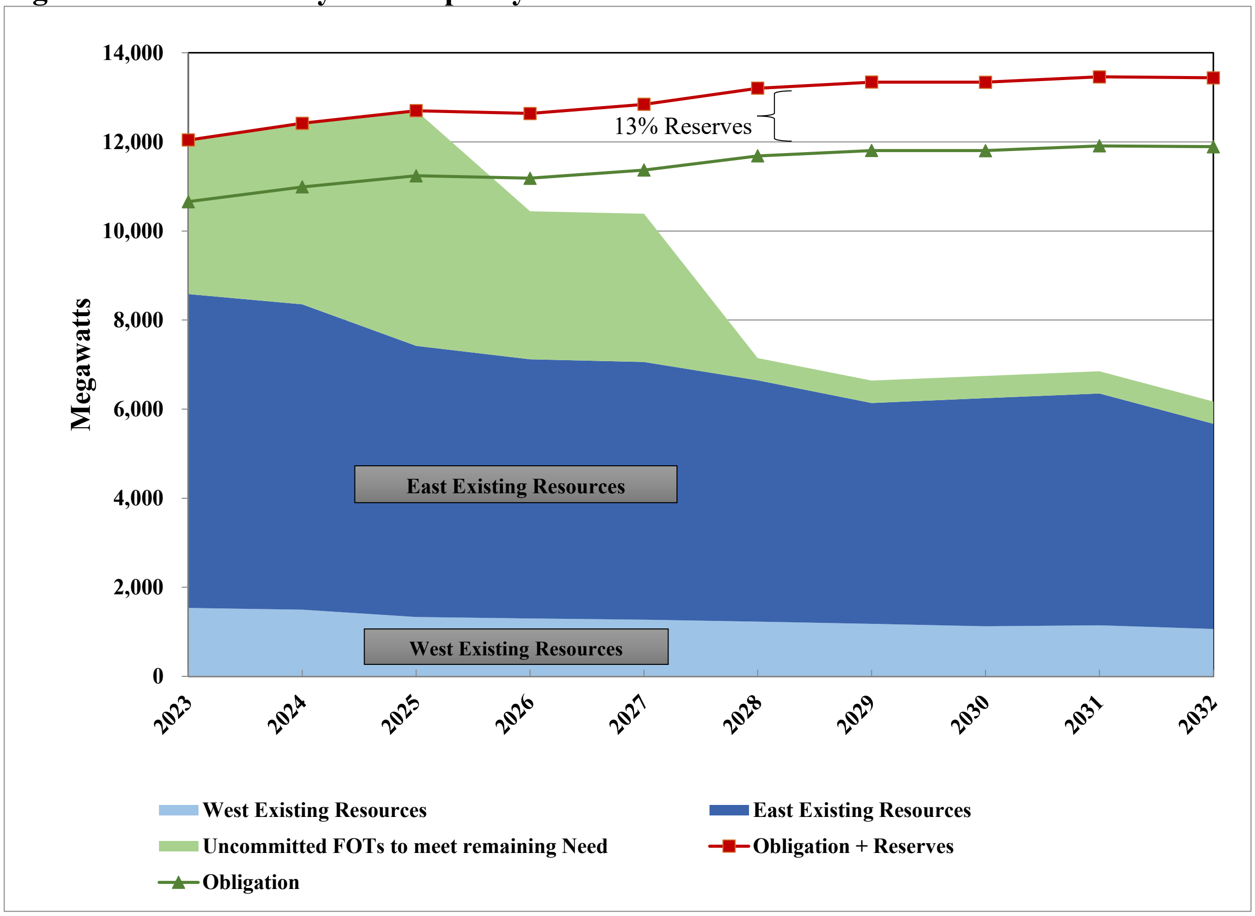


Figure 6.5 – Winter System Capacity Position Trend

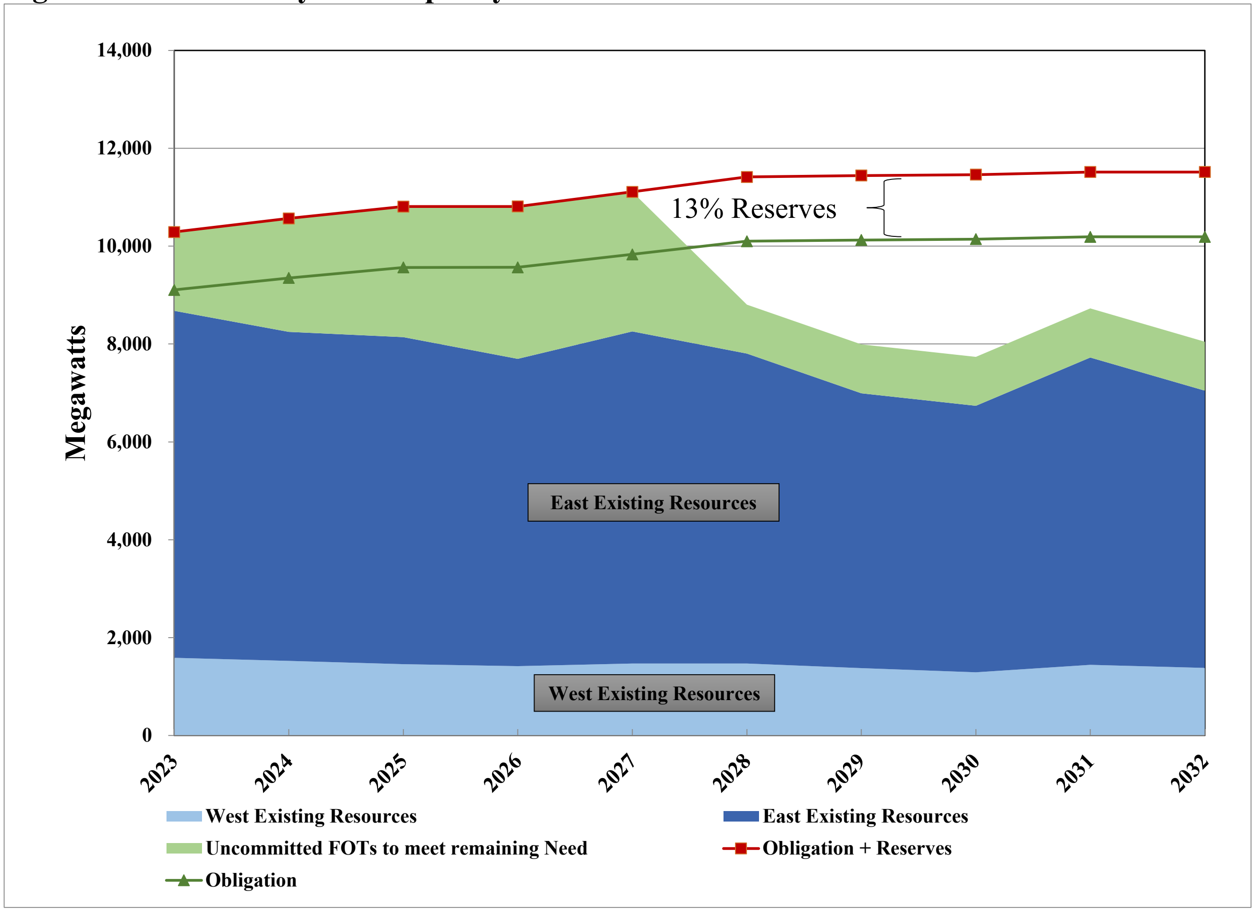


Figure 6.6 – East Summer Capacity Position Trend

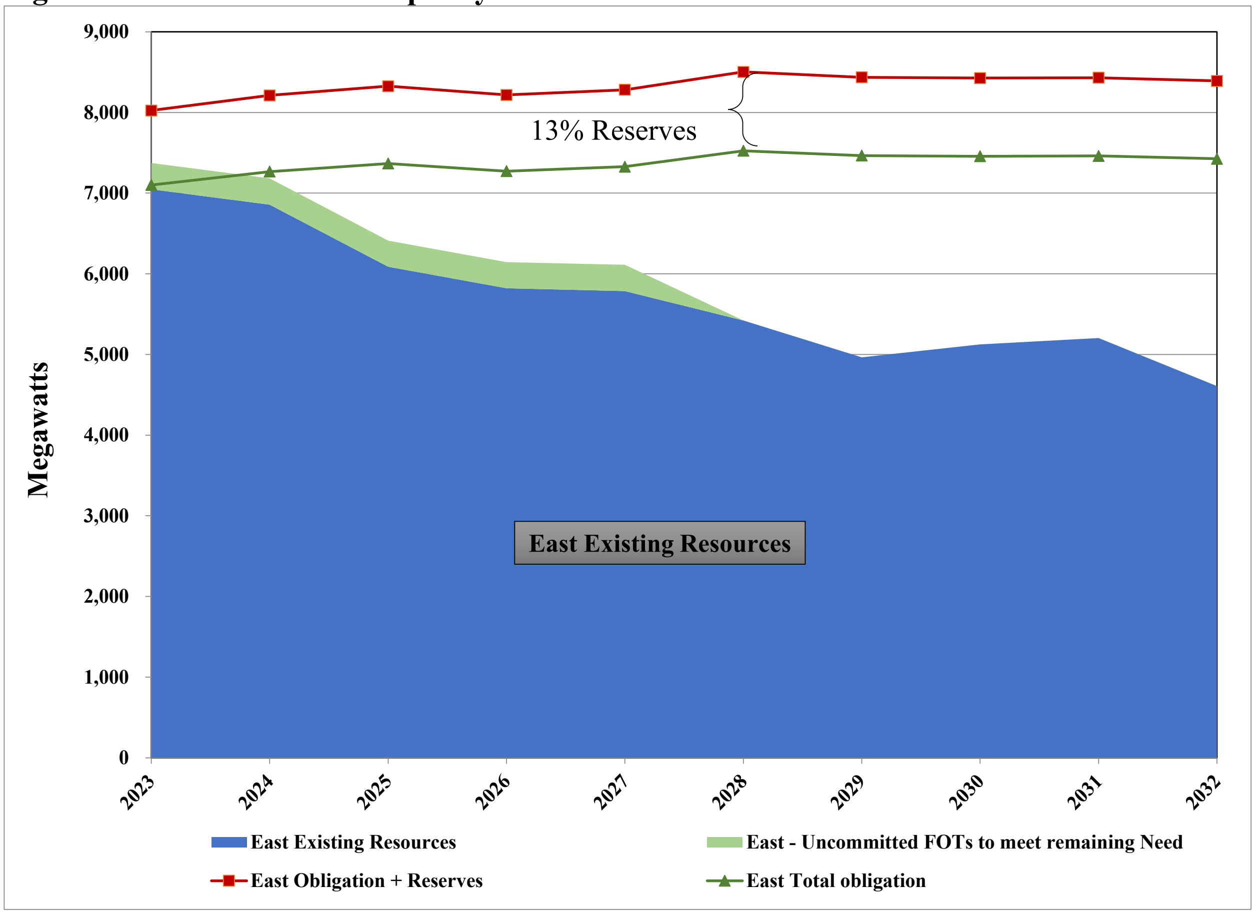
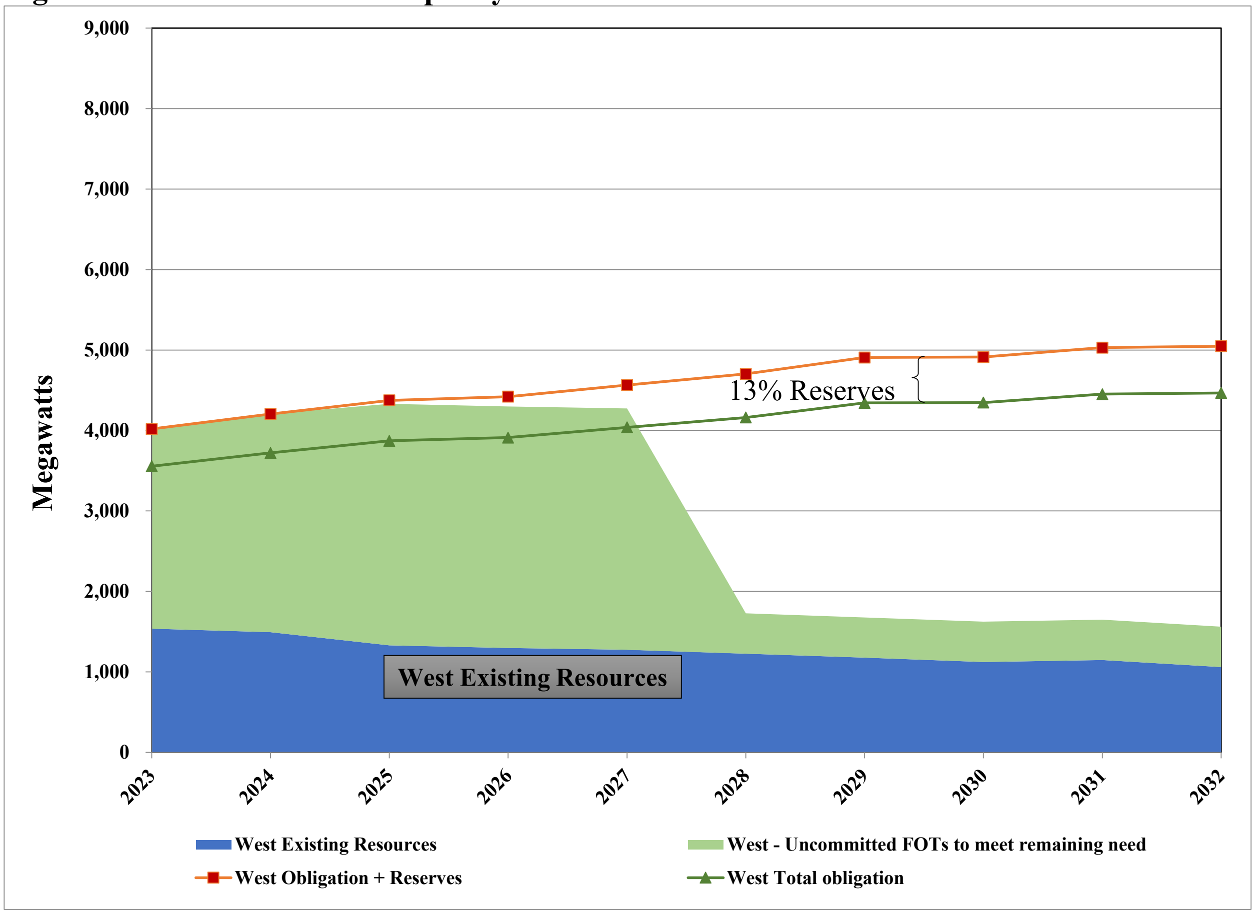


Figure 6.7 – West Summer Capacity Position Trend



CHAPTER 7 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp developed resource attributes and costs for future generation resource options that reflect updated information from project experience, industry vendors, public meeting comments and studies.
- Resource costs have been unstable since the previous integrated resource plan (IRP) and cost increases have been significant. The cost of solar photovoltaic modules and balance of plant equipment increased in 2022, deviating from the downward cost trend of the past several years. Likewise, costs of wind turbines and batteries, and associated balance of plant costs, have shown increases.
- Hypothetical expansion of the Blundell geothermal plant as well as greenfield geothermal costs have been updated to reflect advances in geothermal technology.
- The combustion turbine types, configurations, and siting locations are identified in the supply-side resource options table. Performance and costs have been updated.
- Options for utility scale batteries (20 megawatts (MW) and 200 MW options), renewables (wind and solar) with storage, gravity energy storage systems, pumped hydro energy storage (PHES), one-hundred-hour storage, and adiabatic compressed air energy storage are included in this IRP.
- The Plexos model can endogenously model transmission upgrades.
- PacifiCorp continued to apply cost reduction credits to energy efficiency, reflecting risk mitigation benefits, transmission and distribution investment deferral benefits, and a ten percent market price credit for Washington and Oregon as allowed by the Northwest Power Act.

Introduction

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of utility-scale supply-side generation, demand-side management (DSM) programs, transmission resources and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the various technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures.

Supply-Side Resources

The list of supply-side resource options reflects the realities evidenced through permitting, internally generated studies and externally commissioned studies undertaken to better understand details of available generation resources. Capital costs for some resource options have declined while others have remained stable compared to the 2021 IRP. Wind, Solar, and energy storage resources were updated for 200 MW and 20 MW proxy capacity ratings. The updated information is based on input from WSP's 2023 RENEWABLES IRP Assessment ("Assessment") (Appendix M) and market trends. The WSP report adds offshore wind and gravity energy storage systems. A variety of gas-fueled generating resources were identified after consultation with major suppliers, large engineering-consulting firm and stakeholders. Combustion turbine types and configurations remained unchanged because the market continued to improve the ability of existing technology to provide firming for variable energy resources. The capital and operating costs of simple and combined-cycle gas turbine plants have remained relatively low in recent years, with a fairly flat cost trend.[1] Carbon capture, utilization, and storage (CCUS) retrofit costs were updated using cost data from existing carbon capture facilities, studies and CCUS developers.

Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2021 IRP. This resource list was reviewed and modified to reflect stakeholder input, new technology developments, environmental factors, cost dynamics and anticipated permitting requirements. Once the basic list of resources was determined, the cost-and-performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the supply-side resource table (SSR), which is used to develop inputs for IRP modeling:

- Recent (2022) third-party engineering cost and performance estimates;
- Original equipment manufacturers capital and operation and maintenance estimates;
- Developer cost and performance estimates;
- Publicly available cost and performance estimates;
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes; and
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options.

Black and Veatch and original equipment manufacturers provided estimated capital costs, operating and maintenance costs, performance, operating characteristics and planned outage cycles for simple cycle and combined cycle resources. Carbon capture, utilization and sequestration (CCUS) costs, revenues, and performance were estimated from existing carbon capture facilities, studies and CCUS developers. WSP provided a cost and performance study for solar, wind, energy storage (excluding PHES) and geothermal generation resources (Appendix M). The WSP study builds upon prior studies, updates cost and technical information and adds gravity energy storage options (other than PHES) and offshore wind (OSW). Although, WSP provided compressed air energy storage (CAES) costs, adiabatic CAES costs used in this IRP were obtained from RESC for a project under development within PacifiCorp's territory. In addition to battery costs provided in the WSP study, PacifiCorp added a low capital cost long duration battery technology resource. Small Modular Reactor costs were escalated from those listed in the 2021 IRP.

PacifiCorp or industry installations provide a solid basis for capital/maintenance costs and operating histories. Performance characteristics were adjusted to site-specific conditions identified in the SSR. For instance, the capacity of combustion turbine-based resources varies with elevation and ambient temperature and, to a lesser extent, relative humidity. Adjustments were made for site-specific elevations of actual plants to more generic, regional elevations for future resources. Examples of actual PacifiCorp installations used to develop the cost-and-performance information

[1] While cost-and-performance metrics for natural gas-fired resources are presented in this chapter, there are significant future risks for new greenhouse gas emitting resources. Please refer to Chapter 8 for a discussion of the risks PacifiCorp considered. A sensitivity case will be developed that includes new gas-fired proxy resources.

provided in the SSR include operation and maintenance (O&M) costs for PacifiCorp's Gadsby GE LM6000PC peaking units and the Lake Side 2 combined cycle plant.

PacifiCorp completed an Economic Study Request ("ESR"), submitted by the Oregon Public Utility Commission ("OPUC") Staff March 2022 to have PacifiCorp evaluate the effects of 1.0 GW of Offshore Wind (OSW) generation in southern Oregon, assumed to be interconnected to PacifiCorp's Del Norte substation located in Del Norte, California.

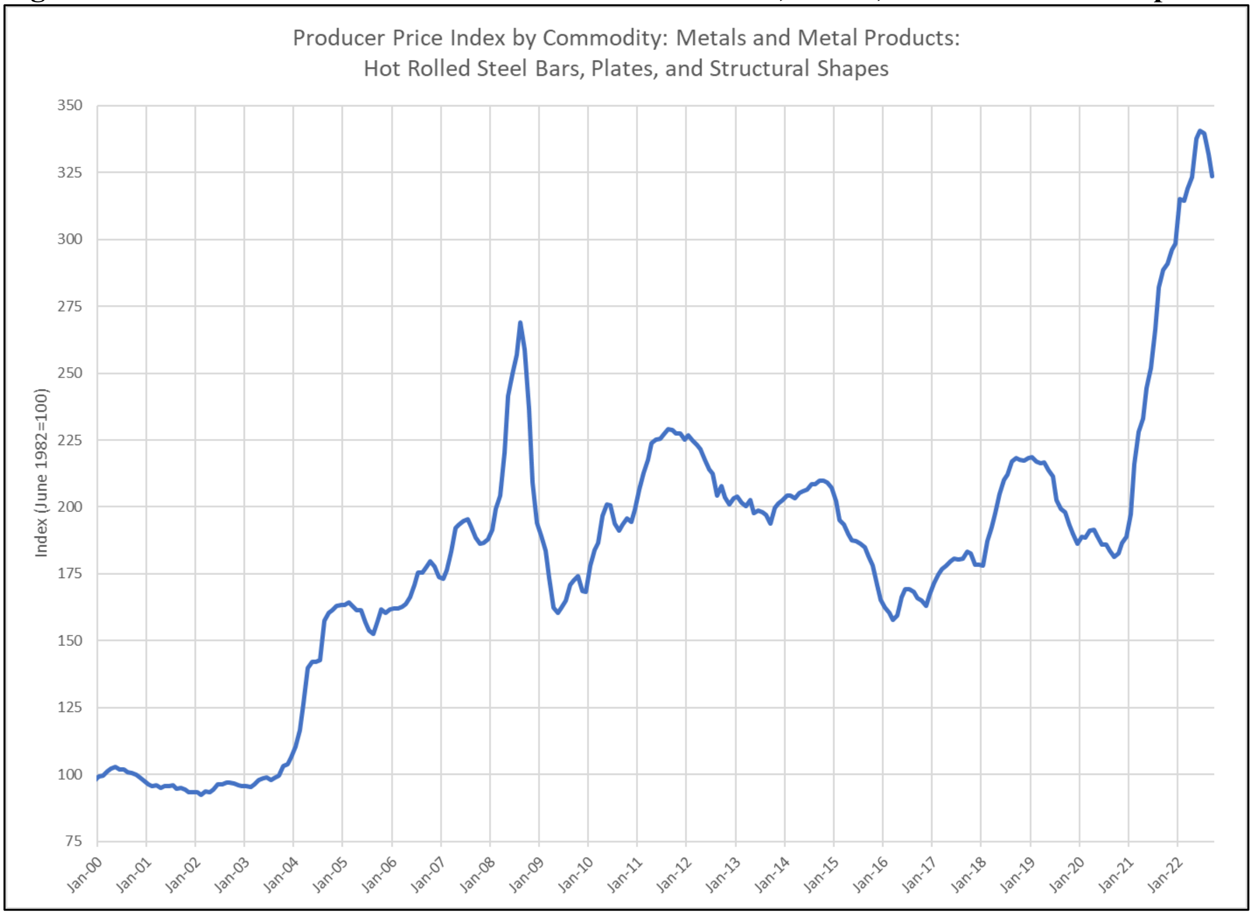
To achieve this, the objective of the ESR study was to provide high-level analyses of how the 1.0 GW of OSW displaces other resources that are integral to the WECC 2032 Anchor Data Set ("ADS") and are serving PacifiCorp network Loads, consistent with Loads and Resources in PacifiCorp 2021 IRP. A conceptual plan of the transmission grid in 10 years, meeting the resource and electric load needs of Southern and Central Oregon cover solutions from generation interconnection cluster studies. In particular, it was critical that transmission solutions were developed through a transparent process, considering the best currently available information, including potential transmission costs, used to establish baseline grid expansion.[2]

Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for some generation technologies is relatively high. Various factors contribute to this uncertainty including new and emerging technologies that have been built at a utility scale, technologies for which relatively few facilities have been built, and projects with multiple year lead times that are exposed to the risk of commodity price fluctuations and economic uncertainty. For example, Figure 7.1 shows the trend in U.S. steel prices over the period from January 2000 through October 2022. This figure illustrates changes in capital costs of generation resources. The 2023 IRP includes demolition costs first introduced in the 2021 IRP. Demolition costs are impacted by the salvage of metals, including steel. Figure 7.2 shows the trend in U.S. carbon steel scrap and illustrates the uncertainty in demolition costs.

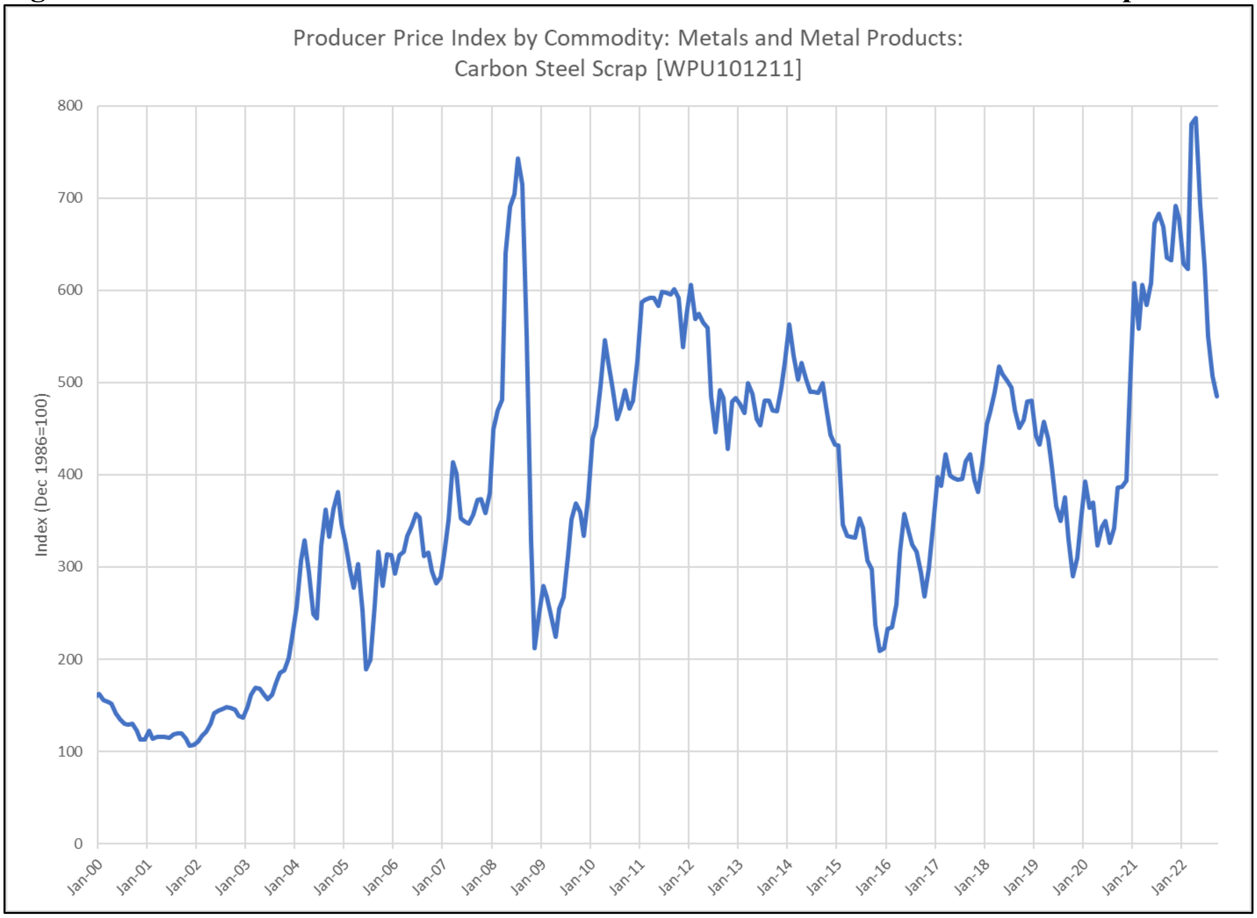
2 https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Adding_OffShore_Wind_at_DelNorte_Draft_ESR_Report.pdf

Figure 7.1 – Producer Price Index: Hot Rolled Steel Bars, Plates, and Structural Shapes[3]



[3] U.S. Bureau of Labor Statistics, Producer Price Index by Commodity: Metals and Metal Products: Hot Rolled Steel Bars, Plates, and Structural Shapes [WPU101704], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/WPU101704, June 13, 2021.

Figure 7.2 – Producer Price Index: Metals and Metal Products: Carbon Steel Scrap[4]



Prices for solar PV modules and balance of plant costs have increased since the 2021 IRP. High demand for renewables and energy storage created by the Inflation Reduction Act combined with trade tariffs and restrictions (US Customs and Border Patrol Withhold Release Orders (WRO)) are believed to have changed the supply and demand balance to drive up costs in the renewables and energy storage markets, especially for the solar market. The Inflation Reduction Act, comprehensive legislation impacting the cost-effectiveness of non-emitting resources, is discussed in Volume I, Chapter 3 (Planning Environment). The solar market is largely affected by WRO's against solar panels with silicon products originating in the Xinjiang province of China, where forced labor conditions violate basic human rights. With regards to lithium-ion batteries for energy storage, although there is a WRO against cobalt mined in the Congo, most lithium-ion battery suppliers are switching from nickel manganese and cobalt (NMC) chemistries to lithium iron phosphate (LFP) chemistries which are safer, less toxic and avoid the need for cobalt which is primarily mined in the Congo where forced labor conditions violate basic human rights. The WSP study provided costs based largely on the US Energy Information Agency (EIA) Annual Technology Baseline (ATB) database; however, those costs were updated prior to the market dynamics described above. PacifiCorp created a cost escalation curve that differs from the ATB forecast (at the time of the WSP Assessment) to account for the observed market conditions. Real prices are projected to continue to remain high until manufacturing capability catches up to demand

[4] U.S. Bureau of Labor Statistics, Producer Price Index by Commodity: Metals and Metal Products: Carbon Steel Scrap [WPU101211], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/WPU101211, June 14, 2021.

and/or until import tariffs and restrictions are lifted. With a lead time of approximately four years for utility scale solar panel orders placed in 2022, solar costs are not expected to decline to previously forecasted costs until 2028. Starting in 2029 the 2023 IRP anticipates the cost of new solar, wind, and lithium-ion batteries will decline and return to 2022 ATB projection from 2032 onward.

Some generation technologies, such as integrated gasification combined cycle (IGCC), as well as CCUS technologies, have shown significant cost uncertainty because only a few units have been built and operated. For example, experience with significant cost overruns on IGCC projects, such as Southern Company's Kemper County IGCC plant, illustrate the difficulty in accurately estimating capital costs of these resource options. Where carbon capture is dependent on revenues from enhanced oil recovery (EOR) to offset costs, the volatility in the price of oil adds an additional level of uncertainty. For example, declining oil prices caused NRG Energy's Petra Nova carbon capture facility to cease operation. The loss of revenue at Petra Nova illustrates the added uncertainty of recovering costs through carbon dioxide sales. As these technologies mature and more facilities are proven at commercial scale, the associated costs may decrease.

The potential to provide reliable capital and operating cost estimates is limited by the number of installed and successfully operated resources. Reliable cost and performance estimates are not expected to be realized until the next generation of new plants are built and successfully operated. As such, future IRPs will be better able to incorporate the potential benefits of future cost reductions. Given the current emphasis on construction and operating experience associated with renewable generation, PacifiCorp anticipates the cost benefits for these technologies to be available sooner. The estimated capital costs are displayed in the SSR along with expected availability of each technology for commercial utilization.

Unless stated otherwise, other resources are assumed to escalate at 2.27% per year.

Resource Options and Attributes

Table 7.1 lists the cost-and-performance attributes for supply-side resource options designated by generic, elevation-specific (for thermal resources) regions where resources could potentially be located:

- 0 feet elevation: international organization for standardization (ISO) conditions (sea level and 59 degrees F); this is used as a reference for certain modeling purposes.
- 1,500 feet elevation: eastern Oregon/Washington.
- 3,000 feet elevation: southern/central Oregon.
- 4,500 feet elevation: northern Utah, specifically Salt Lake/Utah/Tooele/Box Elder counties.
- 5,050 feet elevation: central Utah, southern Idaho, central Wyoming.
- 6,500 feet elevation: southwestern Wyoming.

Table 7.2 and present the total resource cost attributes for supply-side resource options and are based on estimates of the first-year, real-levelized costs for resources, stated in June 2020 dollars. Similar to the approach taken in previous IRPs, it is not currently envisioned that new combined cycle resources could be economically permitted in northern Utah, specifically Salt Lake, Utah, Davis, and Box Elder counties due to state implementation plans for these counties regarding particulate matter of 2.5 microns and less ($PM_{2.5}$).

A Glossary of Terms and a Glossary of Acronyms from the SSR is summarized in Table 7.3 and Table 7.4.

Table 7.1 – 2023 Supply-Side Resource Table (2022$)

Description		Resource Characteristics				Costs				Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Demolition Cost ($/kW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Natural Gas	SCCT Aero x4	0	229	2027	30	$ 1,530	$ 35	$ 0.28	$ 18.68	9241	0.7	2.0	23.0000	0.0014	0.0910	0.2550	120.2000
Natural Gas	SCCT Frame "J" x1	0	354	2027	40	$ 814	$ 21	$ 2.32	$ 14.09	9073	5.6	7.2	0.0000	0.0020	0.0570	0.2550	128.0000
Natural Gas	SCCT Frame "J" x1, 30H2	0	337	2028	40	$ 3,932	$ 28	$ 2.44	$ 44.80	9191	5.6	7.2	121.8750	0.0018	0.0550	0.1785	112.0000
Natural Gas	SCCT Frame "J" X1, 100H2	0	362	2035	40	$ 6,588	$ 31	$ 2.23	$ 69.00	9489	5.6	7.2	406.2500	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF	0	362	2033	40	$ 5,894	$ 31	$ 2.27	$ 66.37	9489	5.6	7.2	406.2500	0.0000	0.0655	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	0	548	2028	40	$ 1,361	$ 21	$ 1.61	$ 22.72	6227	5.6	7.2	7.8000	0.0020	0.0076	0.2550	128.0000
Natural Gas	CCCT Dry "J", DF, 1x1	0	63	2028	40	$ -	$ -	$ 1.15	$ -	8726	5.6	7.2	8.3000	0.0020	0.0076	0.2550	127.0000
Natural Gas	SCCT Aero x4	1,500	216	2027	30	$ 1,619	$ 46	$ 0.30	$ 19.77	9258	0.7	2.0	24.4000	0.0014	0.0910	0.2550	120.3000
Natural Gas	SCCT Frame "J" x1	1,500	338	2027	40	$ 853	$ 28	$ 2.43	$ 14.76	9066	5.6	7.2	0.0000	0.0020	0.0570	0.2550	128.0000
Natural Gas	SCCT Frame "J" x1, 30H2	1,500	322	2028	40	$ 4,118	$ 38	$ 2.55	$ 46.92	9184	5.6	7.2	121.8750	0.0018	0.0550	0.1785	113.0000
Natural Gas	SCCT Frame "J" X1, 100H2	1,500	345	2035	40	$ 6,903	$ 41	$ 2.38	$ 73.77	9481	5.6	7.2	406.2500	0.0000	0.0654	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF	1,500	345	2033	40	$ 6,176	$ 41	$ 2.38	$ 69.54	9481	5.6	7.2	406.2500	0.0000	0.0654	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	1,500	523	2028	40	$ 1,427	$ 28	$ 1.68	$ 23.81	6227	5.6	7.2	7.9000	0.0020	0.0076	0.2550	128.0000
Natural Gas	CCCT Dry "J", DF, 1x1	1,500	63	2028	40	$ -	$ -	$ 1.15	$ -	8688	5.6	7.2	8.5000	0.0020	0.0076	0.2550	127.0000
Natural Gas	SCCT Frame "J" x1, 30H2	3,000	305	2027	40	$ 4,355	$ 38	$ 2.70	$ 49.63	9189	5.6	7.2	121.8750	0.0018	0.0550	0.1785	113.0000
Natural Gas	SCCT Frame "J" X1, 100H2	3,000	327	2034	40	$ 7,297	$ 43	$ 2.52	$ 77.98	9486	5.6	7.2	406.2500	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF	3,000	327	2034	40	$ 6,529	$ 43	$ 2.52	$ 73.52	9486	5.6	7.2	406.2500	0.0000	0.0655	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	3,000	495	2027	40	$ 1,507	$ 27	$ 1.78	$ 25.15	6226	5.6	7.2	8.0000	0.0020	0.0076	0.2550	128.0000
Natural Gas	CCCT Dry "J", DF, 1x1	3,000	63	2028	40	$ -	$ -	$ 1.15	$ -	8705	5.6	7.2	8.7000	0.0020	0.0076	0.2550	127.0000
Natural Gas	SCCT Aero x4	5,050	190	2028	30	$ 1,844	$ 42	$ 0.34	$ 22.54	9326	0.7	2.0	27.8000	0.0014	0.0914	0.2550	120.2000
Natural Gas	SCCT Frame "J" x1	5,050	296	2029	40	$ 971	$ 25	$ 2.78	$ 16.83	9080	5.6	7.2	0.0000	0.0020	0.0571	0.2550	128.0000
Natural Gas	SCCT Frame "J" x1, 30H2	5,050	282	2029	40	$ 4,696	$ 34	$ 2.91	$ 53.53	9197	5.6	7.2	121.8750	0.0018	0.0550	0.1785	112.0000
Natural Gas	SCCT Frame "J" X1, 100H2	5,050	303	2035	40	$ 7,869	$ 37	$ 2.72	$ 84.10	9493	5.6	7.2	406.2500	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF	5,050	303	2035	40	$ 7,041	$ 37	$ 2.72	$ 79.29	9493	5.6	7.2	406.2500	0.0000	0.0655	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	5,050	459	2029	40	$ 1,625	$ 25	$ 1.92	$ 27.13	6234	5.6	7.2	8.2000	0.0019	0.0076	0.2550	128.0000
Natural Gas	CCCT Dry "J", DF, 1x1	5,050	63	2029	40	$ -	$ -	$ 1.15	$ -	8652	5.6	7.2	8.9000	0.0020	0.0076	0.2550	127.0000
Natural Gas	SCCT Aero x4	6,500	171	2028	30	$ 2,044	$ 49	$ 0.38	$ 24.98	9208	0.7	2.0	29.8000	0.0000	0.0913	0.2550	120.3000
Natural Gas	SCCT Frame "J" x1	6,500	283	2028	40	$ 1,017	$ 29	$ 2.91	$ 17.63	9076	5.6	7.2	0.0000	0.0000	0.0571	0.2550	127.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF	6,500	289	2034	40	$ 7,374	$ 44	$ 2.84	$ 83.04	9489	5.6	7.2	406.2500	0.0000	0.0654	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	6,500	437	2027	40	$ 1,704	$ 43	$ 2.01	$ 28.46	6241	5.6	7.2	8.4000	0.0000	0.0076	0.2550	128.0000
Natural Gas	CCCT Dry "J", DF, 1x1	6,500	63	2027	40	$ -	$ -	$ 1.15	$ -	8590	5.6	7.2	9.0000	0.0000	0.0076	0.2550	127.0000
Coal	PC CCUS Oxy-Combustion retrofit @ 100 MW pre-retrofit basis	5,000	-39	2028	30	$ 4,673	$ 37	$ 18.68	$ 54.24	18321	5	5.0	193.1188	0.0040	0.0420	1.2000	6.2400
Coal	PC CCUS retrofit @ 330 MW pre-retrofit basis	6,500	-99	2028	20	$ 2,826	$ 37	$ 21.70	$ 32.71	15632	5	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
Coal	PC CCUS retrofit @ 700 MW pre-retrofit basis	6,500	-187	2028	20	$ 1,932	$ 37	$ 20.79	$ 18.04	14656	5	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
Storage	Li-Ion, 4-hour, 200 MW	N/A	200	2025	20	$ 1,817	$ 24	Included	$ 42.32	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (L-ion, 4hr, 200MW)	N/A	200	2025	20	$ 1,486	$ 24	Included	$ 42.32	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion, 4-hour, 500 MW	N/A	500	2025	20	$ 1,775	$ 24	Included	$ 41.36	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (L-ion, 4hr, 500MW)	N/A	500	2025	20	$ 1,460	$ 24	Included	$ 41.36	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion, 4-hour, 1000 MW	N/A	1,000	2025	20	$ 1,729	$ 24	Included	$ 40.31	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (L-ion, 4hr, 1000MW)	N/A	1,000	2025	20	$ 1,422	$ 24	Included	$ 40.31	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, 4 hour, 200 MW	N/A	200	2025	25	$ 2,458	$ 34	$ 0.03	$ 64.27	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (Flow, 4hr, 200MW)	N/A	200	2025	25	$ 2,060	$ 34	$ -	$ 7.00	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, 4 hour, 1000 MW	N/A	1,000	2025	25	$ 2,281	$ 32	$ 0.13	$ 54.86	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (Flow, 4hr, 1000MW)	N/A	1,000	2025	25	$ 1,892	$ 32	$ -	$ 1.66	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Gravity Battery, 4 hour,	N/A	200	2025	50	$ 3,474	$ 0	Included	$ 80.97	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (Gravity, 4hr, 200MW)	N/A	200	2025	50	$ 1,894	$ 0	Included	$ -	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Gravity Battery, 4 hour,	N/A	500	2025	50	$ 3,249	$ 0	Included	$ 75.75	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (Gravity, 4hr, 500MW)	N/A	500	2025	50	$ 1,695	$ 0	Included	$ -	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Gravity Battery, 4 hour,	N/A	1,000	2025	50	$ 2,026	$ 0	Included	$ 47.25	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Incremental, double energy capacity (Gravity, 4hr, 1000MW)	N/A	1,000	2025	50	$ 988	$ 0	Included	$ -	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 1000 MWh	6500'	125	2026	30	$ 2,310	$ 49	$ 1.05	$ 16.91	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 1250 MWh	6500'	125	2026	30	$ 2,332	$ 49	$ 1.05	$ 16.95	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 1500 MWh	6500'	125	2027	30	$ 2,574	$ 49	$ 1.05	$ 16.99	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 2000 MWh	6500'	125	2027	30	$ 2,659	$ 49	$ 1.05	$ 17.07	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000

Table 7.1 – 2023 Supply-Side Resource Table (2022$) (Continued)

Description		Resource Characteristics				Costs				Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Demolition Cost ($/kW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Storage	Adiabatic CAES, RESC, 125 MW, 3000 MWh	6500'	125	2027	30	$ 2,854	$ 49	$ 1.05	$ 17.23	n/a	0.0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 6000 MWh	6500'	125	2029	30	$ 3,867	$ 49	$ 1.05	$ 17.71	n/a	0.0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 250 MW, 4000 MWh	6500'	250	2028	30	$ 2,440	$ 49	$ 1.05	$ 12.65	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 250 MW, 6000 MWh	6500'	250	2029	30	$ 2,734	$ 49	$ 1.05	$ 12.81	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 250 MW, 12000 MWh	6500'	250	2032	30	$ 3,660	$ 49	$ 1.05	$ 13.29	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 4000 MWh	6500'	500	2028	30	$ 2,013	$ 49	$ 1.05	$ 10.28	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 5000 MWh	6500'	500	2028	30	$ 2,027	$ 49	$ 1.05	$ 10.32	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 6000 MWh	6500'	500	2029	30	$ 2,169	$ 49	$ 1.05	$ 10.36	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 8000 MWh	6500'	500	2030	30	$ 2,315	$ 49	$ 1.05	$ 10.44	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 12000 MWh	6500'	500	2032	30	$ 2,631	$ 49	$ 1.05	$ 10.60	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 500 MW, 24000 MWh	6500'	500	2035	30	$ 3,629	$ 49	$ 1.05	$ 11.08	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Southern OR	N/A	400	2028	100	$ 4,303	$ 485	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Portland North Coast	N/A	400	2028	100	$ 4,303	$ 485	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Central WY	N/A	400	2028	100	$ 4,303	$ 485	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Eastern WY	N/A	400	2028	100	$ 4,303	$ 485	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Central UT	N/A	400	2028	100	$ 4,303	$ 485	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Solar	Idaho Falls, ID, 20 MW, 26.1% CF	4,700	20	2025	25	$ 1,427	$ 29	$ -	$ 20.87	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 20 MW, 27.6% CF	4,800	20	2023	25	$ 1,527	$ 32	$ -	$ 20.87	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Milford, UT, 20 MW, 30.2% CF	5,000	20	2023	25	$ 1,412	$ 29	$ -	$ 20.87	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Milford, UT, 200 MW, 30.2% CF	5,000	200	2023	25	$ 1,140	$ 29	$ -	$ 20.87	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 200 MW, 27.9% CF	6,400	200	2023	25	$ 1,187	$ 30	$ -	$ 20.87	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 200 MW, 24.2% CF	1,000	200	2025	25	$ 1,211	$ 31	$ -	$ 20.87	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Idaho Falls, ID, 200 MW, 26.1% CF + BESS: 100% pwr, 4 hours	4,700	200	2025	25	$ 2,879	$ 54	$ -	$ 63.19	1	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Lakeview, OR, 200 MW, 27.6% CF + BESS: 100% pwr, 4 hours	4,800	200	2025	25	$ 2,864	$ 56	$ -	$ 63.19	1	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Milford, UT, 200 MW, 30.2% CF + BESS: 100% pwr, 4 hours	5,000	200	2025	25	$ 2,881	$ 54	$ -	$ 63.19	1	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Rock Springs, WY, 200 MW, 27.9% CF + BESS: 100% pwr, 4 hours	6,400	200	2025	25	$ 2,902	$ 55	$ -	$ 63.19	1	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Yakima, WA, 200 MW, 24.2% CF + BESS: 100% pwr, 4 hours	1,000	200	2025	25	$ 2,977	$ 56	$ -	$ 63.19	1	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Pocatello, ID, 20 MW, CF: 37.1%	4,500	20	2026	30	$ 2,161	$ 59	$ -	$ 43.00	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Pocatello, ID, 200 MW, CF: 37.1%	4,500	200	2026	30	$ 1,597	$ 59	$ -	$ 43.00	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Arlington, OR, 20 MW, CF: 37.1%	1,500	20	2026	30	$ 2,149	$ 59	$ -	$ 43.00	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Arlington, OR, 200 MW, CF: 37.1%	1,500	200	2026	30	$ 1,567	$ 59	$ -	$ 43.00	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Monticello, UT, 20 MW, CF: 29.5%	4,500	20	2026	30	$ 2,186	$ 59	$ -	$ 43.00	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Monticello, UT, 200 MW, CF: 29.5%	4,500	200	2026	30	$ 1,626	$ 59	$ -	$ 43.00	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Medicine Bow, WY, 20 MW, CF: 43.6%	6,500	20	2026	30	$ 2,129	$ 59	$ -	$ 43.00	n/a	ncluded with CI	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Medicine Bow, WY, 200 MW, CF: 43.6%	6,500	200	2026	30	$ 1,568	$ 59	$ -	$ 43.00	n/a	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Wind	Goldendale, WA, 20 MW, CF: 37.1%	1,500	20	2026	30	$ 2,274	$ 59	$ -	$ 43.00	n/a	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Wind	Goldendale, WA, 200 MW, CF: 37.1%	1,500	200	2026	30	$ 1,660	$ 59	$ -	$ 43.00	n/a	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Wind	Offshore, Northern, CA, CF: 47.0%	0	200	2028	30	$ 4,636	$ 158	$ -	$ 103.00	n/a	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Wind	Offshore, Northern, CA, 1GW, CF: 47.0%	0	1,000	2028	30	$ 4,633	$ 158	$ -	$ 103.00	n/a	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Pocatello, ID, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	4,500	200	2026	30	$ 3,166	$ 83	$ -	$ 85.32	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Arlington, OR, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	200	2026	30	$ 3,332	$ 83	$ -	$ 85.32	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Monticello, UT, 200 MW, CF: 29.5% + BESS: 100% pwr, 4 hours	4,500	200	2026	30	$ 3,252	$ 83	$ -	$ 85.32	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 100% pwr, 4 hours	6,500	200	2026	30	$ 3,389	$ 83	$ -	$ 85.32	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Goldendale, WA, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	200	2026	30	$ 7,244	$ 83	$ -	$ 85.32	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Offshore, Northern, CA, CF: 47.0% + BESS: 100% pwr, 4 hours	0	200	2028	30	$ 5,797	$ 182	$ -	$ 145.32	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Solar+Wind+Storage	Idaho Falls, ID Solar + Wind + BESS: 100% pwr, 4 hours	4,700	200	2026	25	$ 5,797	$ 114	$ -	$ 148.51	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Solar+Wind+Storage	Lakeview, OR Solar + Wind + BESS: 100% pwr, 4 hours	4,800	200	2026	25	$ 6,052	$ 116	$ -	$ 148.51	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Solar+Wind+Storage	Milford, UT Solar + Wind + BESS: 100% pwr, 4 hours	5,000	200	2026	25	$ 6,238	$ 113	$ -	$ 148.51	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Solar+Wind+Storage	Rock Springs, WY Solar + Wind + BESS: 100% pwr, 4 hours	6,400	200	2026	25	$ 5,703	$ 114	$ -	$ 148.51	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Solar+Wind+Storage	Yakima, WA Solar + Wind + BESS: 100% pwr, 4 hours	1,000	200	2026	25	$ 5,898	$ 115	$ -	$ 148.51	85%	ncluded with C	Included with CI	n/a	n/a	n/a	n/a	n/a
Geothermal	Dual Flash Expansion of Blundell Plant	4,500	200	2026	40	$ 3,800	$ 117	$ -	$ 115.00	n/a	0.0	0.0	1,453.3827	n/a	n/a	n/a	n/a
Geothermal	Greenfield Binary Plant	4,500	200	2026	40	$ 5,568	$ 117	$ -	$ 115.00	n/a	0.0	0.0	1,453.3827	n/a	n/a	n/a	n/a
Nuclear	Small Modular Reactor x 12	5,000	854	2028	60	$ 5,706	$ 763	$ 7.11	$ 68.77	N/A	5.0	5.0	na	767.1587	0.0000	0.0000	0.0000

Table 7.2 - Total Resource Cost for Supply-Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
SCCT Aero x4	No	0	$1,530	$35	7.140%	$111.68	$18.68	0.000%	$0.00	$31.94	$50.62	$162.30
SCCT Frame "J" x1	No	0	$814	$21	6.456%	$53.89	$14.09	0.000%	$0.00	$33.77	$47.86	$101.75
SCCT Frame "J" x1, 30H2	No	0	$3,932	$28	6.456%	$255.67	$44.80	0.000%	$0.00	$33.77	$78.57	$334.25
SCCT Frame "J" X1, 100H2	No	0	$6,588	$31	6.456%	$427.34	$69.00	0.000%	$0.00	$33.77	$102.77	$530.11
SCCT Frame "J" X1, 100H2, BF	No	0	$5,894	$31	6.456%	$382.59	$66.37	0.000%	$0.00	$33.77	$100.14	$482.72
CCCT Dry "J", 1X1	No	0	$1,361	$21	6.609%	$91.33	$22.72	2.616%	$0.59	$23.36	$46.67	$138.00
CCCT Dry "J", DF, 1x1	No	0	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$23.36	$23.36	$23.36
SCCT Aero x4	No	1,500	$1,619	$46	7.140%	$118.87	$19.77	0.000%	$0.00	$31.76	$51.54	$170.41
SCCT Frame "J" x1	No	1,500	$853	$28	6.456%	$56.89	$14.76	0.000%	$0.00	$33.71	$48.47	$105.36
SCCT Frame "J" x1, 30H2	No	1,500	$4,118	$38	6.456%	$268.33	$46.92	0.000%	$0.00	$33.71	$80.63	$348.95
SCCT Frame "J" X1, 100H2	No	1,500	$6,903	$41	6.456%	$448.32	$73.77	0.000%	$0.00	$33.71	$107.47	$555.79
SCCT Frame "J" X1, 100H2, BF	No	1,500	$6,176	$41	6.456%	$401.43	$69.54	0.000%	$0.00	$33.71	$103.25	$504.67
CCCT Dry "J", 1X1	No	1,500	$1,427	$28	6.609%	$96.11	$23.81	2.616%	$0.62	$23.17	$47.61	$143.72
CCCT Dry "J", DF, 1x1	No	1,500	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$23.17	$23.17	$23.17
SCCT Frame "J" x1, 30H2	No	3,000	$4,355	$38	6.456%	$283.62	$49.63	0.000%	$0.00	$17.98	$67.61	$351.23
SCCT Frame "J" X1, 100H2	No	3,000	$7,297	$43	6.456%	$473.86	$77.98	0.000%	$0.00	$17.98	$95.96	$569.82
SCCT Frame "J" X1, 100H2, BF	No	3,000	$6,529	$43	6.456%	$424.29	$73.52	0.000%	$0.00	$17.98	$91.49	$515.79
CCCT Dry "J", 1X1	No	3,000	$1,507	$27	6.609%	$101.38	$25.15	2.616%	$0.66	$12.27	$38.09	$139.46
CCCT Dry "J", DF, 1x1	No	3,000	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$12.27	$12.27	$12.27
SCCT Aero x4	Yes	5,050	$1,844	$42	7.140%	$134.64	$22.54	0.000%	$0.00	$14.06	$36.60	$171.24
SCCT Frame "J" x1	Yes	5,050	$971	$25	6.456%	$64.31	$16.83	0.000%	$0.00	$14.93	$31.76	$96.07
SCCT Frame "J" x1, 30H2	No	5,050	$4,696	$34	6.456%	$305.37	$53.53	0.000%	$0.00	$14.93	$68.46	$373.83
SCCT Frame "J" X1, 100H2	Yes	5,050	$7,869	$37	6.456%	$510.43	$84.10	0.000%	$0.00	$14.93	$99.04	$609.47
SCCT Frame "J" X1, 100H2, BF	No	5,050	$7,041	$37	6.456%	$456.98	$79.29	0.000%	$0.00	$14.93	$94.22	$551.20
CCCT Dry "J", 1X1	Yes	5,050	$1,625	$25	6.609%	$109.01	$27.13	2.616%	$0.71	$9.84	$37.69	$146.70
CCCT Dry "J", DF, 1x1	Yes	5,050	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$9.84	$9.84	$9.84
SCCT Aero x4	Yes	6,500	$2,044	$49	7.140%	$149.43	$24.98	0.000%	$0.00	$9.13	$34.11	$183.54
SCCT Frame "J" x1	Yes	6,500	$1,017	$29	6.456%	$67.52	$17.63	0.000%	$0.00	$9.70	$27.33	$94.84
SCCT Frame "J" X1, 100H2, BF	No	6,500	$7,374	$44	6.456%	$479	$83.04	0.000%	$0.00	$9.70	$92.74	$571.70
CCCT Dry "J", 1X1	Yes	6,500	$1,704	$43	6.609%	$115	$28.46	2.616%	$0.74	$6.62	$35.83	$151.31
CCCT Dry "J", DF, 1x1	Yes	6,500	$0	$0	6.609%	$0	$0.00	2.616%	$0.00	$6.62	$6.62	$6.62
PC CCUS Oxy-Combustion retrofit @ 100 MW pre-retrofit basis	Yes	5,000	$4,673	$37	7.289%	$343	$54.24	5.541%	$3.01	$0.00	$57.25	$400.54

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
PC CCUS retrofit @ 330 MW pre-retrofit basis	Yes	6,500	$2,826	$37	8.887%	$254.47	$32.71	5.541%	$1.81	$0.00	$34.52	$288.99
PC CCUS retrofit @ 700 MW pre-retrofit basis	Yes	6,500	$1,932	$37	8.903%	$175.28	$18.04	5.541%	$1.00	$0.00	$19.04	$194.32
Li-Ion, 4-hour, 200 MW	No	N/A	$1,817	$24	8.405%	$154.74	$42.32	0.000%	$0.00	$0.00	$42.32	$197.05
Incremental, double energy capacity (L-ion, 4hr, 200MW)	No	N/A	$1,486	$24	8.405%	$126.95	$42.32	0.000%	$0.00	$0.00	$42.32	$169.27
Li-Ion, 4-hour, 500 MW	Yes	N/A	$1,775	$24	8.405%	$151.18	$41.36	0.000%	$0.00	$0.00	$41.36	$192.54
Incremental, double energy capacity (L-ion, 4hr, 500MW)	Yes	N/A	$1,460	$24	8.405%	$124.70	$41.36	0.000%	$0.00	$0.00	$41.36	$166.06
Li-Ion, 4-hour, 1000 MW	No	N/A	$1,729	$24	8.405%	$147.31	$40.31	0.000%	$0.00	$0.00	$40.31	$187.62
Incremental, double energy capacity (L-ion, 4hr, 1000MW)	No	N/A	$1,422	$24	8.405%	$121.55	$40.31	0.000%	$0.00	$0.00	$40.31	$161.85
Flow Battery, 4 hour, 200 MW	Yes	N/A	$2,458	$34	8.405%	$209.47	$64.27	0.000%	$0.00	$0.00	$64.27	$273.74
Incremental, double energy capacity (Flow, 4hr, 200MW)	Yes	N/A	$2,060	$34	8.405%	$175.97	$7.00	0.000%	$0.00	$0.00	$7.00	$182.97
Flow Battery, 4 hour, 1000 MW	No	N/A	$2,281	$32	8.405%	$194.44	$54.86	0.000%	$0.00	$0.00	$54.86	$249.30
Incremental, double energy capacity (Flow, 4hr, 1000MW)	Yes	N/A	$1,892	$32	8.405%	$161.67	$1.66	0.000%	$0.00	$0.00	$1.66	$163.33
Gravity Battery, 4 hour,	Yes	N/A	$3,474	$0	8.405%	$292.01	$80.97	0.000%	$0.00	$0.00	$80.97	$372.98
Incremental, double energy capacity (Gravity, 4hr, 200MW)	Yes	N/A	$1,894	$0	8.405%	$159.20	$0.00	0.000%	$0.00	$0.00	$0.00	$159.20
Gravity Battery, 4 hour,	Yes	N/A	$3,249	$0	8.405%	$273.08	$75.75	0.000%	$0.00	$0.00	$75.75	$348.84
Incremental, double energy capacity (Gravity, 4hr, 500MW)	Yes	N/A	$1,695	$0	8.405%	$142.53	$0.00	0.000%	$0.00	$0.00	$0.00	$142.53
Gravity Battery, 4 hour,	Yes	N/A	$2,026	$0	8.405%	$170.31	$47.25	0.000%	$0.00	$0.00	$47.25	$217.55
Incremental, double energy capacity (Gravity, 4hr, 1000MW)	No	N/A	$988	$0	8.405%	$83.05	$0.00	0.000%	$0.00	$0.00	$0.00	$83.05
Adiabatic CAES, RESC, 125 MW, 1000 MWh	No	6500'	$2,310	$49	8.633%	$203.65	$16.91	5.480%	$0.93	$0.00	$17.84	$221.49
Adiabatic CAES, RESC, 125 MW, 1250 MWh	No	6500'	$2,332	$49	8.633%	$205.58	$16.95	5.480%	$0.93	$0.00	$17.88	$223.46
Adiabatic CAES, RESC, 125 MW, 1500 MWh	No	6500'	$2,574	$49	8.633%	$226.48	$16.99	5.480%	$0.93	$0.00	$17.92	$244.40
Adiabatic CAES, RESC, 125 MW, 2000 MWh	No	6500'	$2,659	$49	8.633%	$233.81	$17.07	5.480%	$0.94	$0.00	$18.01	$251.81
Adiabatic CAES, RESC, 125 MW, 3000 MWh	No	6500'	$2,854	$49	8.633%	$250.68	$17.23	5.480%	$0.94	$0.00	$18.18	$268.86
Adiabatic CAES, RESC, 125 MW, 6000 MWh	No	6500'	$3,867	$49	8.633%	$338.10	$17.71	5.480%	$0.97	$0.00	$18.68	$356.78
Adiabatic CAES, RESC, 250 MW, 4000 MWh	No	6500'	$2,440	$49	8.633%	$214.91	$12.65	5.480%	$0.69	$0.00	$13.35	$228.26
Adiabatic CAES, RESC, 250 MW, 6000 MWh	No	6500'	$2,734	$49	8.633%	$240.30	$12.81	5.480%	$0.70	$0.00	$13.52	$253.81
Adiabatic CAES, RESC, 250 MW, 12000 MWh	No	6500'	$3,660	$49	8.633%	$320.20	$13.29	5.480%	$0.73	$0.00	$14.02	$334.22
Adiabatic CAES, RESC, 500 MW, 4000 MWh	Yes	6500'	$2,013	$49	8.633%	$178.03	$10.28	5.480%	$0.56	$0.00	$10.85	$188.88
Adiabatic CAES, RESC, 500 MW, 5000 MWh	No	6500'	$2,027	$49	8.633%	$179.26	$10.32	5.480%	$0.57	$0.00	$10.89	$190.15
Adiabatic CAES, RESC, 500 MW, 6000 MWh	Yes	6500'	$2,169	$49	8.633%	$191.49	$10.36	5.480%	$0.57	$0.00	$10.93	$202.43

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
Adiabatic CAES, RESC, 500 MW, 8000 MWh	No	6500'	$2,315	$49	8.633%	$204.12	$10.44	5.480%	$0.57	$0.00	$11.02	$215.14
Adiabatic CAES, RESC, 500 MW, 12000 MWh	No	6500'	$2,631	$49	8.633%	$231.42	$10.60	5.480%	$0.58	$0.00	$11.19	$242.61
Adiabatic CAES, RESC, 500 MW, 24000 MWh	No	6500'	$3,629	$49	8.633%	$317.57	$11.08	5.480%	$0.61	$0.00	$11.69	$329.26
Pumped Hydro, Southern OR	Yes	N/A	$4,303	$485	5.567%	$266.55	$18.00	2.617%	$0.47	$0.00	$18.47	$285.02
Pumped Hydro, Portland North Coast	Yes	N/A	$4,303	$485	5.567%	$266.55	$18.00	2.617%	$0.47	$0.00	$18.47	$285.02
Pumped Hydro, Central WY	Yes	N/A	$4,303	$485	5.567%	$266.55	$18.00	2.617%	$0.47	$0.00	$18.47	$285.02
Pumped Hydro, Eastern WY	Yes	N/A	$4,303	$485	5.567%	$266.55	$18.00	2.617%	$0.47	$0.00	$18.47	$285.02
Pumped Hydro, Central UT	Yes	N/A	$4,303	$485	5.567%	$266.55	$18.00	2.617%	$0.47	$0.00	$18.47	$285.02
Idaho Falls, ID, 20 MW, 26.1% CF	Yes	4,700	$1,427	$29	5.056%	$73.62	$20.87	1.370%	$0.29	$0.00	$21.16	$94.77
Lakeview, OR, 20 MW, 27.6% CF	Yes	4,800	$1,527	$32	5.056%	$78.78	$20.87	1.370%	$0.29	$0.00	$21.16	$99.94
Milford, UT, 20 MW, 30.2% CF	Yes	5,000	$1,412	$29	5.056%	$72.88	$20.87	1.370%	$0.29	$0.00	$21.16	$94.04
Milford, UT, 200 MW, 30.2% CF	Yes	5,000	$1,140	$29	5.056%	$59.13	$20.87	1.370%	$0.29	$0.00	$21.16	$80.29
Rock Springs, WY, 200 MW, 27.9% CF	Yes	6,400	$1,187	$30	5.056%	$61.56	$20.87	1.370%	$0.29	$0.00	$21.16	$82.72
Yakima, WA, 200 MW, 24.2% CF	Yes	1,000	$1,211	$31	5.056%	$62.78	$20.87	1.370%	$0.29	$0.00	$21.16	$83.94
Idaho Falls, ID, 200 MW, 26.1% CF + BESS: 100% pwr, 4 hours	No	4,700	$2,879	$54	5.056%	$148.28	$63.19	1.370%	$0.87	$0.00	$64.06	$212.34
Lakeview, OR, 200 MW, 27.6% CF + BESS: 100% pwr, 4 hours	No	4,800	$2,864	$56	5.056%	$147.63	$63.19	1.370%	$0.87	$0.00	$64.06	$211.69
Milford, UT, 200 MW, 30.2% CF + BESS: 100% pwr, 4 hours	No	5,000	$2,881	$54	5.056%	$148.37	$63.19	1.370%	$0.87	$0.00	$64.06	$212.43
Rock Springs, WY, 200 MW, 27.9% CF + BESS: 100% pwr, 4 hours	No	6,400	$2,902	$55	5.056%	$149.51	$63.19	1.370%	$0.87	$0.00	$64.06	$213.57
Yakima, WA, 200 MW, 24.2% CF + BESS: 100% pwr, 4 hours	No	1,000	$2,977	$56	5.056%	$153.34	$63.19	1.370%	$0.87	$0.00	$64.06	$217.39
Pocatello, ID, 20 MW, CF: 37.1%	Yes	4,500	$2,161	$59	6.657%	$147.82	$43.00	4.392%	$1.89	$0.00	$44.89	$192.71
Pocatello, ID, 200 MW, CF: 37.1%	Yes	4,500	$1,597	$59	6.657%	$110.25	$43.00	4.392%	$1.89	$0.00	$44.89	$155.14
Arlington, OR, 20 MW, CF: 37.1%	Yes	1,500	$2,149	$59	6.657%	$147.04	$43.00	4.392%	$1.89	$0.00	$44.89	$191.92
Arlington, OR, 200 MW, CF: 37.1%	Yes	1,500	$1,567	$59	6.657%	$108.27	$43.00	4.392%	$1.89	$0.00	$44.89	$153.16
Monticello, UT, 20 MW, CF: 29.5%	Yes	4,500	$2,186	$59	6.657%	$149.48	$43.00	4.392%	$1.89	$0.00	$44.89	$194.37
Monticello, UT, 200 MW, CF: 29.5%	Yes	4,500	$1,626	$59	6.657%	$112.20	$43.00	4.392%	$1.89	$0.00	$44.89	$157.09
Medicine Bow, WY, 20 MW, CF: 43.6%	Yes	6,500	$2,129	$59	6.657%	$145.71	$43.00	4.392%	$1.89	$0.00	$44.89	$190.60
Medicine Bow, WY, 200 MW, CF: 43.6%	Yes	6,500	$1,568	$59	6.657%	$108.31	$43.00	4.392%	$1.89	$0.00	$44.89	$153.20
Goldendale, WA, 20 MW, CF: 37.1%	Yes	1,500	$2,274	$59	6.657%	$155.32	$43.00	4.392%	$1.89	$0.00	$44.89	$200.21
Goldendale, WA, 200 MW, CF: 37.1%	Yes	1,500	$1,660	$59	6.657%	$114.49	$43.00	4.392%	$1.89	$0.00	$44.89	$159.38
Offshore, Northern, CA, CF: 47.0%	Yes	0	$4,636	$158	6.657%	$319.13	$103.00	4.392%	$4.52	$0.00	$107.52	$426.66
Offshore, Northern, CA, 1GW, CF: 47.0%	Yes	0	$4,633	$158	6.657%	$318.98	$103.00	4.392%	$4.52	$0.00	$107.52	$426.50
Pocatello, ID, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	No	4,500	$3,166	$83	6.657%	$216.30	$85.32	4.392%	$3.75	$0.00	$89.07	$305.36
Arlington, OR, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	No	1,500	$3,332	$83	6.657%	$227.34	$85.32	4.392%	$3.75	$0.00	$89.07	$316.40
Monticello, UT, 200 MW, CF: 29.5% + BESS: 100% pwr, 4 hours	No	4,500	$3,252	$83	6.657%	$222.05	$85.32	4.392%	$3.75	$0.00	$89.07	$311.12
Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 100% pwr, 4 hours	No	6,500	$3,389	$83	6.657%	$231.15	$85.32	4.392%	$3.75	$0.00	$89.07	$320.21
Goldendale, WA, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	No	1,500	$7,244	$83	6.657%	$487.79	$85.32	4.392%	$3.75	$0.00	$89.07	$576.85
Offshore, Northern, CA, CF: 47.0% + BESS: 100% pwr, 4 hours	No	0	$5,797	$182	6.657%	$398.02	$145.32	4.392%	$6.38	$0.00	$151.70	$549.72
Idaho Falls, ID Solar + Wind + BESS: 100% pwr, 4 hours	No	4,700	$5,797	$114	6.657%	$393.44	$148.51	4.392%	$6.52	$0.00	$155.03	$548.47
Lakeview, OR Solar + Wind + BESS: 100% pwr, 4 hours	No	4,800	$6,052	$116	6.657%	$410.55	$148.51	4.392%	$6.52	$0.00	$155.03	$565.58
Milford, UT Solar + Wind + BESS: 100% pwr, 4 hours	No	5,000	$6,238	$113	6.657%	$422.78	$148.51	4.392%	$6.52	$0.00	$155.03	$577.81
Rock Springs, WY Solar + Wind + BESS: 100% pwr, 4 hours	No	6,400	$5,703	$114	6.657%	$387.27	$148.51	4.392%	$6.52	$0.00	$155.03	$542.30
Yakima, WA Solar + Wind + BESS: 100% pwr, 4 hours	No	1,000	$5,898	$115	6.657%	$400.27	$148.51	4.392%	$6.52	$0.00	$155.03	$555.30
Dual Flash Expansion of Blundell Plant	Yes	4,500	$3,800	$117	6.015%	$235.61	$115.00	0.872%	$1.00	$0.00	$116.00	$351.61
Greenfield Binary Plant	Yes	4,500	$5,568	$117	6.015%	$341.93	$115.00	0.872%	$1.00	$0.00	$116.00	$457.93
Small Modular Reactor x 12	Yes	5,000	$5,706	$763	5.846%	$378.19	$68.77	9.424%	$6.48	$0.00	$75.26	$453.45

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)		Convert to $/MWh			Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 2/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
SCCT Aero x4	0	33%	$56.14	N/A	$ 4.46	$ 41.26	$ 0.28	14.14%	$ 0.04	$ -	$97.72	$ -	$97.72
SCCT Frame "J" x1	0	33%	$35.20	N/A	$ 4.46	$ 40.51	$ 2.32	14.14%	$ 0.33	$ -	$78.36	$ -	$78.36
SCCT Frame "J" x1, 30H2	0	33%	$115.62	N/A	$ 11.14	$ 102.41	$ 2.44	14.14%	$ 0.34	$ -	$220.81	$ -	$220.81
SCCT Frame "J" X1, 100H2	0	33%	$183.38	N/A	$ 26.72	$ 253.59	$ 2.23	14.14%	$ 0.32	$ -	$439.51	$ (31.91)	$407.60
SCCT Frame "J" X1, 100H2, BF	0	33%	$166.99	N/A	$ 26.72	$ 253.59	$ 2.27	14.14%	$ 0.32	$ -	$423.17	$ (28.55)	$394.62
CCCT Dry "J", 1X1	0	78%	$20.20	N/A	$ 4.46	$ 27.80	$ 1.61	14.39%	$ 0.23	$ -	$49.84	$ -	$49.84
CCCT Dry "J", DF, 1x1	0	12%	$22.22	N/A	$ 4.46	$ 38.96	$ 1.15	14.39%	$ 0.16	$ -	$62.49	$ -	$62.49
SCCT Aero x4	1,500	33%	$58.95	N/A	$ 4.46	$ 41.33	$ 0.30	14.14%	$ 0.04	$ -	$100.62	$ -	$100.62
SCCT Frame "J" x1	1,500	33%	$36.45	N/A	$ 4.46	$ 40.48	$ 2.43	14.14%	$ 0.34	$ -	$79.70	$ -	$79.70
SCCT Frame "J" x1, 30H2	1,500	33%	$120.71	N/A	$ 11.14	$ 102.33	$ 2.55	14.14%	$ 0.36	$ -	$225.96	$ -	$225.96
SCCT Frame "J" X1, 100H2	1,500	33%	$192.26	N/A	$ 26.72	$ 253.37	$ 2.38	14.14%	$ 0.34	$ -	$448.35	$ (33.44)	$414.91
SCCT Frame "J" X1, 100H2, BF	1,500	33%	$174.58	N/A	$ 26.72	$ 253.37	$ 2.38	14.14%	$ 0.34	$ -	$430.67	$ (29.92)	$400.75
CCCT Dry "J", 1X1	1,500	78%	$21.03	N/A	$ 4.46	$ 27.80	$ 1.68	14.39%	$ 0.24	$ -	$50.76	$ -	$50.76
CCCT Dry "J", DF, 1x1	1,500	12%	$22.04	N/A	$ 4.46	$ 38.79	$ 1.15	14.39%	$ 0.16	$ -	$62.14	$ -	$62.14
SCCT Frame "J" x1, 30H2	3,000	33%	$121.50	N/A	$ 11.22	$ 103.10	$ 2.70	14.14%	$ 0.38	$ -	$227.68	$ -	$227.68
SCCT Frame "J" X1, 100H2	3,000	33%	$197.12	N/A	$ 26.72	$ 253.51	$ 2.52	14.14%	$ 0.36	$ -	$453.50	$ (35.35)	$418.15
SCCT Frame "J" X1, 100H2, BF	3,000	33%	$178.42	N/A	$ 26.72	$ 253.51	$ 2.52	14.14%	$ 0.36	$ -	$434.80	$ (31.63)	$403.18
CCCT Dry "J", 1X1	3,000	78%	$20.41	N/A	$ 4.57	$ 28.48	$ 1.78	14.39%	$ 0.26	$ -	$50.92	$ -	$50.92
CCCT Dry "J", DF, 1x1	3,000	12%	$11.68	N/A	$ 4.57	$ 39.82	$ 1.15	14.39%	$ 0.16	$ -	$52.81	$ -	$52.81
SCCT Aero x4	5,050	33%	$59.24	N/A	$ 4.42	$ 41.24	$ 0.34	14.14%	$ 0.05	$ -	$100.87	$ -	$100.87
SCCT Frame "J" x1	5,050	33%	$33.23	N/A	$ 4.42	$ 40.15	$ 2.78	14.14%	$ 0.39	$ -	$76.55	$ -	$76.55
SCCT Frame "J" x1, 30H2	5,050	33%	$129.32	N/A	$ 11.11	$ 102.21	$ 2.91	14.14%	$ 0.41	$ -	$234.85	$ -	$234.85
SCCT Frame "J" X1, 100H2	5,050	33%	$210.83	N/A	$ 26.72	$ 253.70	$ 2.72	14.14%	$ 0.38	$ -	$467.62	$ (38.11)	$429.51
SCCT Frame "J" X1, 100H2, BF	5,050	33%	$190.67	N/A	$ 26.72	$ 253.70	$ 2.72	14.14%	$ 0.38	$ -	$447.47	$ (34.10)	$413.36
CCCT Dry "J", 1X1	5,050	78%	$21.47	N/A	$ 4.42	$ 27.57	$ 1.92	14.39%	$ 0.28	$ -	$51.23	$ -	$51.23
CCCT Dry "J", DF, 1x1	5,050	12%	$9.36	N/A	$ 4.42	$ 38.26	$ 1.15	14.39%	$ 0.16	$ -	$48.93	$ -	$48.93
SCCT Aero x4	6,500	33%	$63.49	N/A	$ 4.33	$ 39.89	$ 0.38	14.14%	$ 0.05	$ -	$103.82	$ -	$103.82
SCCT Frame "J" x1	6,500	33%	$32.81	N/A	$ 4.33	$ 39.32	$ 2.91	14.14%	$ 0.41	$ -	$75.45	$ -	$75.45
SCCT Frame "J" X1, 100H2, BF	6,500	33%	$197.76	N/A	$ 26.72	$ 253.58	$ 2.84	14.14%	$ 0.40	$ -	$454.59	$ (35.72)	$418.87
CCCT Dry "J", 1X1	6,500	78%	$22.14	N/A	$ 4.33	$ 27.04	$ 2.01	14.39%	$ 0.29	$ -	$51.49	$ -	$51.49
CCCT Dry "J", DF, 1x1	6,500	12%	$6.30	N/A	$ 4.33	$ 37.21	$ 1.15	14.39%	$ 0.16	$ -	$44.82	$ -	$44.82
PC CCUS Oxy-Combustion retrofit @ 100 MW pre-retrofit basis	5,000	90%	$50.80	N/A	$ 4.42	$ 81.01	$ 18.68	0.00%	$ -	$ -	$150.50	$ (54.36)	$96.13

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)		Convert to $/MWh			Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
PC CCUS retrofit @ 330 MW pre-retrofit basis	6,500	90%	$36.66	N/A	$ 4.42	$ 69.13	$ 21.70	0.00%	$ -	$ -	$127.48	$ (43.13)	$84.35
PC CCUS retrofit @ 700 MW pre-retrofit basis	6,500	90%	$24.65	N/A	$ 4.42	$ 64.81	$ 20.79	0.00%	$ -	$ -	$110.24	$ (40.44)	$69.81
Li-Ion, 4-hour, 200 MW	N/A	17%	$132.32	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$132.32	$ -	$132.32
Incremental, double energy capacity (L-ion, 4hr, 200MW)	N/A	34%	$56.83	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$56.83	$ -	$56.83
Li-Ion, 4-hour, 500 MW	N/A	17%	$129.29	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$129.29	$ -	$129.29
Incremental, double energy capacity (L-ion, 4hr, 500MW)	N/A	34%	$55.75	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$55.75	$ -	$55.75
Li-Ion, 4-hour, 1000 MW	N/A	17%	$125.99	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$125.99	$ -	$125.99
Incremental, double energy capacity (L-ion, 4hr, 1000MW)	N/A	34%	$54.34	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$54.34	$ -	$54.34
Flow Battery, 4 hour, 200 MW	N/A	17%	$183.82	N/A	$ -	$ -	$ 0.03	0.00%	$ -	$ -	$183.84	$ -	$183.84
Incremental, double energy capacity (Flow, 4hr, 200MW)	N/A	34%	$61.43	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$61.43	$ -	$61.43
Flow Battery, 4 hour, 1000 MW	N/A	17%	$167.41	N/A	$ -	$ -	$ 0.13	0.00%	$ -	$ -	$167.54	$ -	$167.54
Incremental, double energy capacity (Flow, 4hr, 1000MW)	N/A	34%	$54.84	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$54.84	$ -	$54.84
Gravity Battery, 4 hour,	N/A	17%	$250.46	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$250.46	$ -	$250.46
Incremental, double energy capacity (Gravity, 4hr, 200MW)	N/A	34%	$53.45	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$53.45	$ -	$53.45
Gravity Battery, 4 hour,	N/A	17%	$234.24	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$234.24	$ -	$234.24
Incremental, double energy capacity (Gravity, 4hr, 500MW)	N/A	34%	$47.85	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$47.85	$ -	$47.85
Gravity Battery, 4 hour,	N/A	17%	$146.09	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$146.09	$ -	$146.09
Incremental, double energy capacity (Gravity, 4hr, 1000MW)	N/A	34%	$27.88	N/A	$ -	$ -	Included	0.00%	$ -	$ -	$27.88	$ -	$27.88
Adiabatic CAES, RESC, 125 MW, 1000 MWh	6500'	33%	$75.85	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$76.97	$ -	$76.97
Adiabatic CAES, RESC, 125 MW, 1250 MWh	6500'	42%	$61.22	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$62.34	$ -	$62.34
Adiabatic CAES, RESC, 125 MW, 1500 MWh	6500'	50%	$55.80	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$56.91	$ -	$56.91
Adiabatic CAES, RESC, 125 MW, 2000 MWh	6500'	67%	$43.12	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$44.23	$ -	$44.23
Adiabatic CAES, RESC, 125 MW, 3000 MWh	6500'	80%	$38.36	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$39.48	$ -	$39.48
Adiabatic CAES, RESC, 125 MW, 6000 MWh	6500'	80%	$50.91	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$52.03	$ -	$52.03
Adiabatic CAES, RESC, 250 MW, 4000 MWh	6500'	67%	$39.09	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$40.20	$ -	$40.20
Adiabatic CAES, RESC, 250 MW, 6000 MWh	6500'	80%	$36.22	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$37.33	$ -	$37.33
Adiabatic CAES, RESC, 250 MW, 12000 MWh	6500'	80%	$47.69	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$48.81	$ -	$48.81
Adiabatic CAES, RESC, 500 MW, 4000 MWh	6500'	33%	$64.68	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$65.80	$ -	$65.80
Adiabatic CAES, RESC, 500 MW, 5000 MWh	6500'	42%	$52.09	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$53.21	$ -	$53.21
Adiabatic CAES, RESC, 500 MW, 6000 MWh	6500'	50%	$46.22	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$47.33	$ -	$47.33
Adiabatic CAES, RESC, 500 MW, 8000 MWh	6500'	67%	$36.84	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$37.95	$ -	$37.95

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)					Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
Adiabatic CAES, RESC, 500 MW, 12000 MWh	6500'	80%	$34.62	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$35.73	$ -	$35.73
Adiabatic CAES, RESC, 500 MW, 24000 MWh	6500'	80%	$46.98	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$48.10	$ -	$48.10
Pumped Hydro, Southern OR	N/A	42%	$78.09	N/A	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ -	$78.60
Pumped Hydro, Portland North Coast	N/A	42%	$78.09	N/A	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ -	$78.60
Pumped Hydro, Central WY	N/A	42%	$78.09	N/A	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ -	$78.60
Pumped Hydro, Eastern WY	N/A	42%	$78.09	N/A	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ -	$78.60
Pumped Hydro, Central UT	N/A	42%	$78.09	N/A	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ -	$78.60
Idaho Falls, ID, 20 MW, 26.1% CF	4,700	26%	$41.45	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$41.45	$ -	$41.45
Lakeview, OR, 20 MW, 27.6% CF	4,800	28%	$41.33	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$41.33	$ -	$41.33
Milford, UT, 20 MW, 30.2% CF	5,000	30%	$35.55	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$35.55	$ -	$35.55
Milford, UT, 200 MW, 30.2% CF	5,000	30%	$30.35	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$30.35	$ -	$30.35
Rock Springs, WY, 200 MW, 27.9% CF	6,400	28%	$33.85	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$33.85	$ -	$33.85
Yakima, WA, 200 MW, 24.2% CF	1,000	24%	$39.59	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$39.59	$ -	$39.59
Idaho Falls, ID, 200 MW, 26.1% CF + BESS: 100% pwr, 4 hours	4,700	26%	$92.87	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$92.87	$ (16.12)	$76.75
Lakeview, OR, 200 MW, 27.6% CF + BESS: 100% pwr, 4 hours	4,800	28%	$87.55	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$87.55	$ (16.12)	$71.43
Milford, UT, 200 MW, 30.2% CF + BESS: 100% pwr, 4 hours	5,000	30%	$80.30	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$80.30	$ (16.12)	$64.17
Rock Springs, WY, 200 MW, 27.9% CF + BESS: 100% pwr, 4 hours	6,400	28%	$87.38	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$88.36	$ (16.12)	$72.23
Yakima, WA, 200 MW, 24.2% CF + BESS: 100% pwr, 4 hours	1,000	24%	$102.55	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$103.52	$ (16.12)	$87.40
Pocatello, ID, 20 MW, CF: 37.1%	4,500	37%	$59.30	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$60.27	$ (16.12)	$44.14
Pocatello, ID, 200 MW, CF: 37.1%	4,500	37%	$47.74	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$48.71	$ (16.12)	$32.58
Arlington, OR, 20 MW, CF: 37.1%	1,500	37%	$59.05	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$60.03	$ (16.12)	$43.90
Arlington, OR, 200 MW, CF: 37.1%	1,500	37%	$47.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$48.10	$ (9.67)	$38.42
Monticello, UT, 20 MW, CF: 29.5%	4,500	30%	$75.22	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$76.19	$ (9.67)	$66.51
Monticello, UT, 200 MW, CF: 29.5%	4,500	30%	$60.79	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$61.76	$ (9.67)	$52.09
Medicine Bow, WY, 20 MW, CF: 43.6%	6,500	44%	$49.90	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$50.88	$ (9.67)	$41.20
Medicine Bow, WY, 200 MW, CF: 43.6%	6,500	44%	$40.11	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$41.08	$ (9.67)	$31.41
Goldendale, WA, 20 MW, CF: 37.1%	1,500	37%	$61.60	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$62.58	$ (16.12)	$46.45
Goldendale, WA, 200 MW, CF: 37.1%	1,500	37%	$49.04	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$50.01	$ (16.12)	$33.89
Offshore, Northern, CA, CF: 47.0%	0	47%	$103.63	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$104.60	$ (13.36)	$91.24
Offshore, Northern, CA, 1GW, CF: 47.0%	0	47%	$103.59	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$104.56	$ (13.36)	$91.20
Pocatello, ID, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	4,500	37%	$93.96	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$94.93	$ (11.56)	$83.37
Arlington, OR, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	37%	$97.36	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$98.09	$ (12.17)	$85.92
Monticello, UT, 200 MW, CF: 29.5% + BESS: 100% pwr, 4 hours	4,500	30%	$120.39	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$121.13	$ (14.94)	$106.19
Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 100% pwr, 4 hours	6,500	44%	$83.84	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$84.57	$ (10.53)	$74.04
Goldendale, WA, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	37%	$177.50	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$178.23	$ (26.46)	$151.77
Offshore, Northern, CA, CF: 47.0% + BESS: 100% pwr, 4 hours	0	47%	$133.52	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$134.25	$ (16.71)	$117.54
Idaho Falls, ID Solar + Wind + BESS: 100% pwr, 4 hours	4,700	26%	$239.89	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$240.63	$ (30.09)	$210.53
Lakeview, OR Solar + Wind + BESS: 100% pwr, 4 hours	4,800	28%	$233.93	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$234.66	$ (29.71)	$204.95
Milford, UT Solar + Wind + BESS: 100% pwr, 4 hours	5,000	30%	$218.41	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$219.15	$ (27.99)	$191.16
Rock Springs, WY Solar + Wind + BESS: 100% pwr, 4 hours	6,400	28%	$221.89	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$222.62	$ (27.70)	$194.92
Yakima, WA Solar + Wind + BESS: 100% pwr, 4 hours	1,000	24%	$261.94	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$262.68	$ (33.02)	$229.66
Dual Flash Expansion of Blundell Plant	4,500	90%	$44.60	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$45.33	$ (16.12)	$29.21
Greenfield Binary Plant	4,500	90%	$58.08	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$58.82	$ (16.12)	$42.69
Small Modular Reactor x 12	5,000	86%	$60.19	N/A	$ -	$ -	$ 7.11	0.00%	$ -	$ 0.74	$68.03	$ (5.98)	$62.05

Table 7.3 - Glossary of Terms from the Supply-Side Resource Table

Term	Description
Fuel	Primary fuel used for electricity generation or storage.
Resource	Primary technology used for electricity generation or storage.
Elevation (afsl)	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW)	For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition.
Commercial Operation Year	The resource availability year is the earliest year the technology associated with the given generating resource is commercially available for procurement and installation. The total implementation time is the number of years necessary to implement all phases of resource development and construction: site selection, permitting, maintenance contracts, IRP approval, RFP process, owner's engineering, construction, commissioning and grid interconnection.
Design Life (years)	Average number of years the resource is expected to be "used and useful," based on various factors such as manufacturer's guarantees, fuel availability and environmental regulations.
Base Capital ($/kW)	Total capital expenditure in dollars per kilowatt-hour ($/kW) for the development and construction of a resource including: direct costs (equipment, buildings, installation/overnight construction, commissioning, contractor fees/profit and contingency), owner's costs (land, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, owner's contingency), and financial costs (allowance for funds used during construction (AFUDC), capital surcharge, property taxes and escalation during construction, if applicable).
Var O&M ($/MWh)	Includes real levelized variable operating costs such as combustion turbine maintenance, water costs, boiler water/circulating water treatment chemicals, pollution control reagents, equipment maintenance and fired hour fees in dollars per megawatt hour ($/MWh).
Fixed O&M ($/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment and training.
Demolition Cost ($/kW)	Total cost to decommission and demolish the generating unit at the end of life in dollars per kilowatt ($/kW).
Full Load Heat Rate HHV (Btu/kWh)	Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis.
EFOR (%)	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates for a given resource at the given site.
POR (%)	Estimated Planned Outage Rate for a given resource at the given site.

Term	Description
Water Consumed (gal/MWh)	Average amount of water consumed by a resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO_2 (lbs/MMBtu)	Expected permitted level of sulfur dioxide (SO_2) emissions in pounds of sulfur dioxide per million Btu of heat input.
NOx (lbs/MMBtu)	Expected permitted level of nitrogen oxides (NO_x) (expressed as NO_2) in pounds of NOx per million Btu of heat input.
Hg (lbs/TBtu)	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO_2 (lbs/MMBtu)	Pounds of carbon dioxide (CO_2) emitted per million Btu of heat input.

Table 7.4 - Glossary of Acronyms Used in the Supply-Side Resources

Acronyms	Description
AFSL	Average Feet (Above) Sea Level
ATB	Annual Technology Baseline
CAES	Compressed Air Energy Storage
CCCT	Combined Cycle Combustion Turbine
CCUS	Carbon Capture, Utilization and Storage
CF	Capacity Factor
CSP	Concentrated Solar Power
DF	Duct Firing
IC	Internal Combustion
IGCC	Integrated Gasification Combined Cycle
ISO	International Organization for Standardization (Temp = 59 F/15 C, Pressure = 14.7 psia/1.013 bar)
Li-Ion	Lithium Ion
LFP	Lithium Iron Phosphate (sub-chemistry of lithium-ion)
NCM	Nickel Cobalt Manganese (sub-chemistry of lithium-ion)
OSW	Offshore Wind
PPA	Power Purchase Agreement
PC CCUS	Pulverized Coal retrofitted with Carbon Capture, Utilization and Storage
PHES	Pumped Hydro Energy Storage
PV Poly-Si	Photovoltaic modules constructed from poly-crystalline silicon semiconductor wafers
Recip	Reciprocating Engine
SCCT	Simple Cycle Combustion Turbine

Resource Option Descriptions

The following are brief descriptions of each of the resources listed in Table 7.1.

Natural Gas, Simple Combined Cycle Turbine (SCCT) Aero x 4 – a resource based on four General Electric simple cycle aero-derivative combustion turbines fueled on natural gas. The scope would include selective catalytic reduction systems and oxidation catalysts to reduce NO_X and carbon monoxide/volatile organic compounds (VOC) emissions.

Natural Gas, SCCT Frame "J" x 1 – a resource based on one General Electric 7HA.02 simple cycle frame type combustion turbine fueled by natural gas. Scope would not include selective catalytic reduction systems to reduce NOx emissions because the engines can meet the emissions requirements with the expected capacity factor.

Brownfield SCCT Frame "J" x1 - a resource located at an existing generating facility based on one General Electric 7HA.02 simple cycle frame type combustion turbine fueled by natural gas. Scope would not include selective catalytic reduction systems to reduce NOx emissions because the engines can meet the emissions requirements with the expected capacity factor.

Natural Gas, SCCT Frame "J" x 1, 30H2 – a resource based on one General Electric 7HA.02 simple cycle frame type combustion turbine fueled by 30 percent hydrogen and 70 percent natural gas. Scope would not include selective catalytic reduction systems to reduce NOx emissions because the engines can meet the emissions requirements with the expected capacity factor.

Natural Gas, SCCT Frame "J" x 1, 100H2 – a resource based on one General Electric 7HA.02 simple cycle frame type combustion turbine fueled by 100 percent hydrogen. Scope would not include selective catalytic reduction systems to reduce NOx emissions because the engines can meet the emissions requirements with the expected capacity factor.

Natural Gas, CCCT Dry "J", 1x1 – a combined cycle resource based on one frame-type General Electric 7HA.02 combustion turbine (air-cooled), one 3-pressure heat recovery steam generator and one steam turbine. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. Steam from the steam turbine is condensed in an air-cooled condenser.

Coal, PC CCUS Oxy-Combustion retrofit at 100 MW pre-retrofit – a retrofit of an existing conventional coal-fueled boiler and steam-turbine generator resource with an oxy-combustion carbon capture technology. Costs include the reduction in plant output due to increased auxiliary power requirements. The CCUS would remove above 95 percent of the carbon dioxide and would provide reductions in other emissions.

Coal, PC CCUS at 330 MW pre-retrofit – a retrofit of an existing conventional coal-fired boiler and steam-turbine generator resource with a post-combustion carbon capture technology. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output. The CCUS would remove 90 percent of the carbon dioxide and would provide reductions in other emissions.

Coal, PC CCUS at 700 MW pre-retrofit – a retrofit of an existing conventional coal-fired boiler and steam-turbine generator resource with a post-combustion carbon capture technology. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output. The CCUS would remove 90 percent of the carbon dioxide and would provide reductions in other emissions.

Wind, 37 percent Net Capacity Factor (NCF) WA/OR/ID – a wind resource based on 3.4 MW wind turbines located in Washington, Oregon, or Idaho with an estimated annual net capacity factor of 37.1 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Wind, 29 percent NCF UT – a wind resource based on 3.4 MW wind turbines located in Utah with an estimated annual net capacity factor of 29.5 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Wind, 43 percent NCF WY – a wind resource based on 3.4 MW wind turbines located in Wyoming with an estimated annual net capacity factor of 43.6 percent.

Wind, Offshore Northern California, 47 percent NCF – a wind resource based on 6.0 MW wind turbines located off the coast of northern California or southern Oregon with an estimated annual net capacity factor of 47.0 percent.

Wind + Energy Storage – a wind resource as described above paired with a 4-hour battery with 100% of the power capacity of the wind resource. The batteries paired with wind resources in the previous IRP had 50% of the power of the wind resources.

Solar, PV Single Axis Tracking in ID, OR, UT, WA, and WY with NCF between 24.2 and 30.2 percent depending upon location (1.30 MWdc/MWac) – a large utility scale (20 MW or 200 MW) solar photovoltaic resource using crystalline silica solar panels in a single axis tracking system located in Idaho Falls, Idaho; Lakeview, Oregon; Milford, Utah; Rock Springs, WY; and Yakima, Washington.

Solar + Energy Storage – a solar resource as described above paired with a 4-hour battery with 100% of the power capacity of the solar resource. The batteries paired with solar resources in the previous IRP had 50% of the power of the solar resources.

Storage, Pumped Hydro Storage – a nominal 400 MW PHES system using a combination of natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 hours combined with recharging that capacity over 14 hours. Total development time is estimated at 10 years due to permitting and construction durations. The total round-trip efficiency for this resource is projected to be 78 percent.

Storage, Lithium Ion Battery –lithium-ion batteries rated at 200, 500, and 1,000 MW capacities with 4-hour duration. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year. The total round-trip efficiency for this resource is projected to be 83 percent.

Incremental, double energy capacity – to double the duration of the energy storage resource in the preceding row, costs on this row must be added to the costs in the row above.

Storage, Flow Battery – a battery utilizing electrolyte solution that changes its chemical state when flowing through a cell. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year. The total round-trip efficiency for this resource is projected to be 70 percent.

Storage, Adiabatic CAES – compressed air energy storage (CAES) system consists of air storage reservoir pressurized by a compressor similar to a conventional gas turbine compression section but driven by an electric motor coupled with an adiabatic power generation turbine. The compressed air powers the adiabatic turbine. Energy is stored by compressing air into the storage reservoir. System sizes of 125, 250 and 500 MW are assumed. The air storage reservoir is assumed to be solution mined to size for the indicated MWh of energy storage. No natural gas is required to generate power. The total round-trip efficiency for this resource is projected to be 69 percent. The CAES resource modeled in the 2019 and prior IRPs was a diabatic system which differed from this resource in that it required burning fuel in the power generation turbine similar to a gas turbine engine.

Storage, One-hundred-hour duration -
Nuclear, Small Modular Reactor – such systems hold the promise of being built off-site and transported to a location at lower cost than traditional nuclear facilities. A nominal 854 MW concept is included. It is recognized that this concept is still in the design and licensing stage and is not commercially available requiring approximately 7 years for availability.

Resource Types

Renewables
PacifiCorp retained WSP to evaluate various renewable energy resources in support of the development of the 2023 IRP and associated resource acquisition portfolios and/or products. The WSP Assessment (Volume II, Appendix M) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and O&M costs that are representative of renewable energy and storage technologies listed below. The Assessment contains preliminary information in support of the long-term power supply planning process. Any technologies of interest to PacifiCorp shall be followed by additional detailed studies during procurement proposal evaluation to further investigate each technology and its direct application within the owner's long-term plans. The following technologies are addressed in the WSP Assessment.

- Geothermal
- Solar
- Wind
- Energy Storage
    - Lithium-Ion Battery
    - Flow Battery
    - Gravity Battery
    - Compressed Air
- Solar + Energy Storage
- Wind + Energy Storage
- Wind + Solar + Energy Storage

Each renewable resource is defined within the Assessment. General assumptions, technology specific assumptions and cost inclusions and exclusions are described within the Assessment. The following paragraphs discuss highlights from the Assessment, a comparison to previous IRP data and additional assessment performed by PacifiCorp.

Costs
The following costs which were excluded from the renewables costs estimates were added by PacifiCorp:

- AFUDC
- Escalation
- Sales tax
- Property taxes and insurance
- Utility demand costs

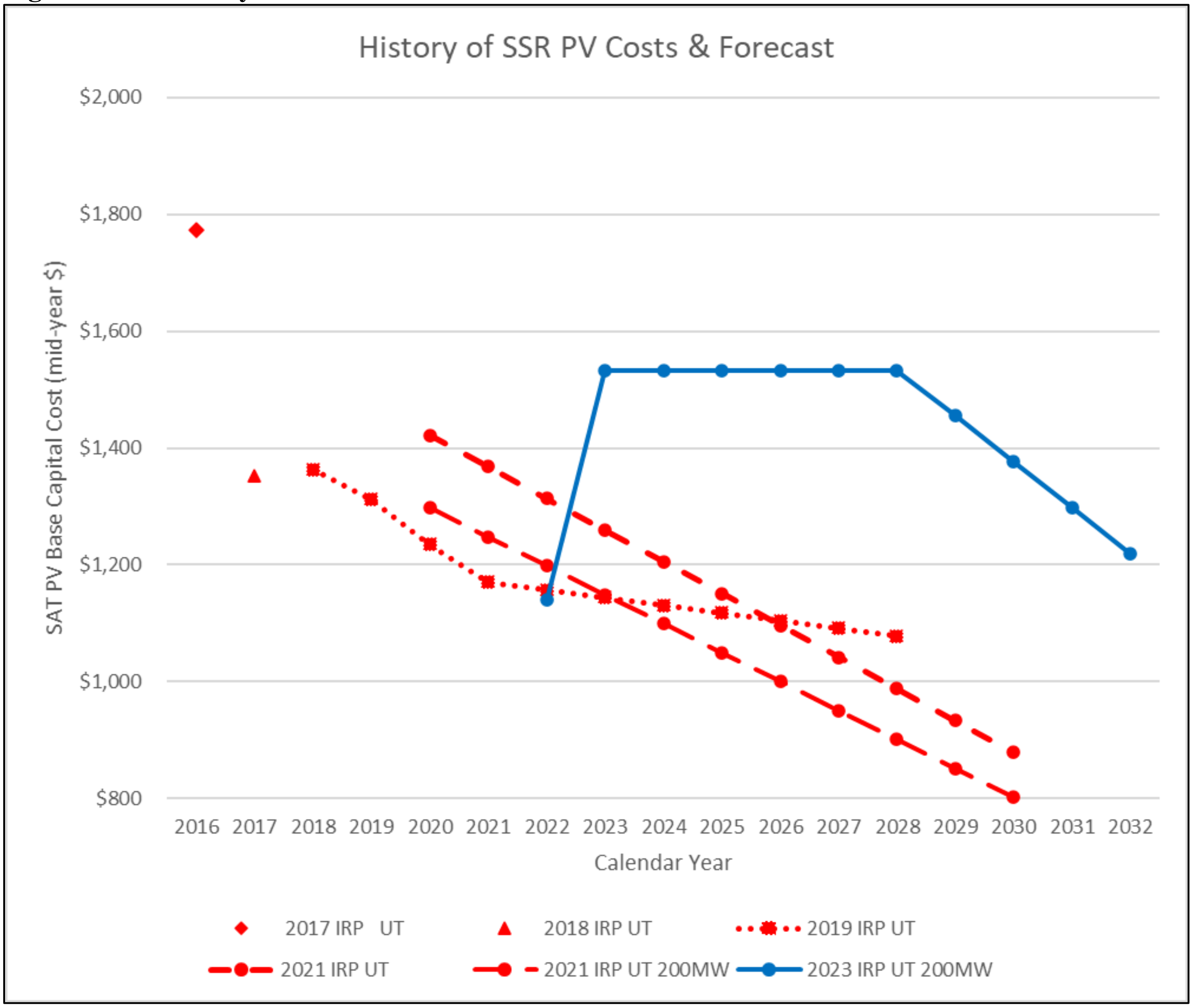
Solar
The WSP Assessment includes 20 MW, and 200 MW single axis tracking (SAT), PV options evaluated at five locations within the PacifiCorp services area. The 2023 IRP differs from the previous IRP in the following ways:

- The 100 MW option was removed as most bids in response to Company Requests for Proposals in the near future are expected to leverage advantages at the 200 MW size.
- 20 MW options were added to comply with Washington regulation WAC 480-100-620, as well as Oregon House Bill 2021, which expanded a requirement for small-scale renewables of up to 20 MW.

Initially, 2022 solar cost estimates used for the 2023 IRP closely matched the forecasted costs from the 2021 IRP. However recent global changes appear to have driven up capital costs for solar PV generation projects. Three events are believed to have significantly contributed to the increase in cost: 1) inflation, 2) higher demand largely due to Inflation Reduction Act incentives, and 3) trade restrictions intended to discourage unethical labor practices, particularly in China where most of the market's crystalline panels are produced.

Figure 7.3 shows a history of capital cost forecasts used in the SSR for PV resources in Utah. The 2023 IRP Capital cost estimates for solar resources are based upon a combination of information sources including the WSP Assessment, recent studies from NREL and others, and from PacifiCorp's experience. The red lines show the forecasts from previous IRP's. The data from IRP's prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2023 IRP price forecast at the 200 MW scale. The sharp increase from 2022 to 2023 represents the observed market correction. The cost increase is assumed to remain in place until panel producers fulfill all back-orders, and increase manufacturing capability to keep up with market demand.

Figure 7.3 – History of SSR PV Cost & Forecast



Wind

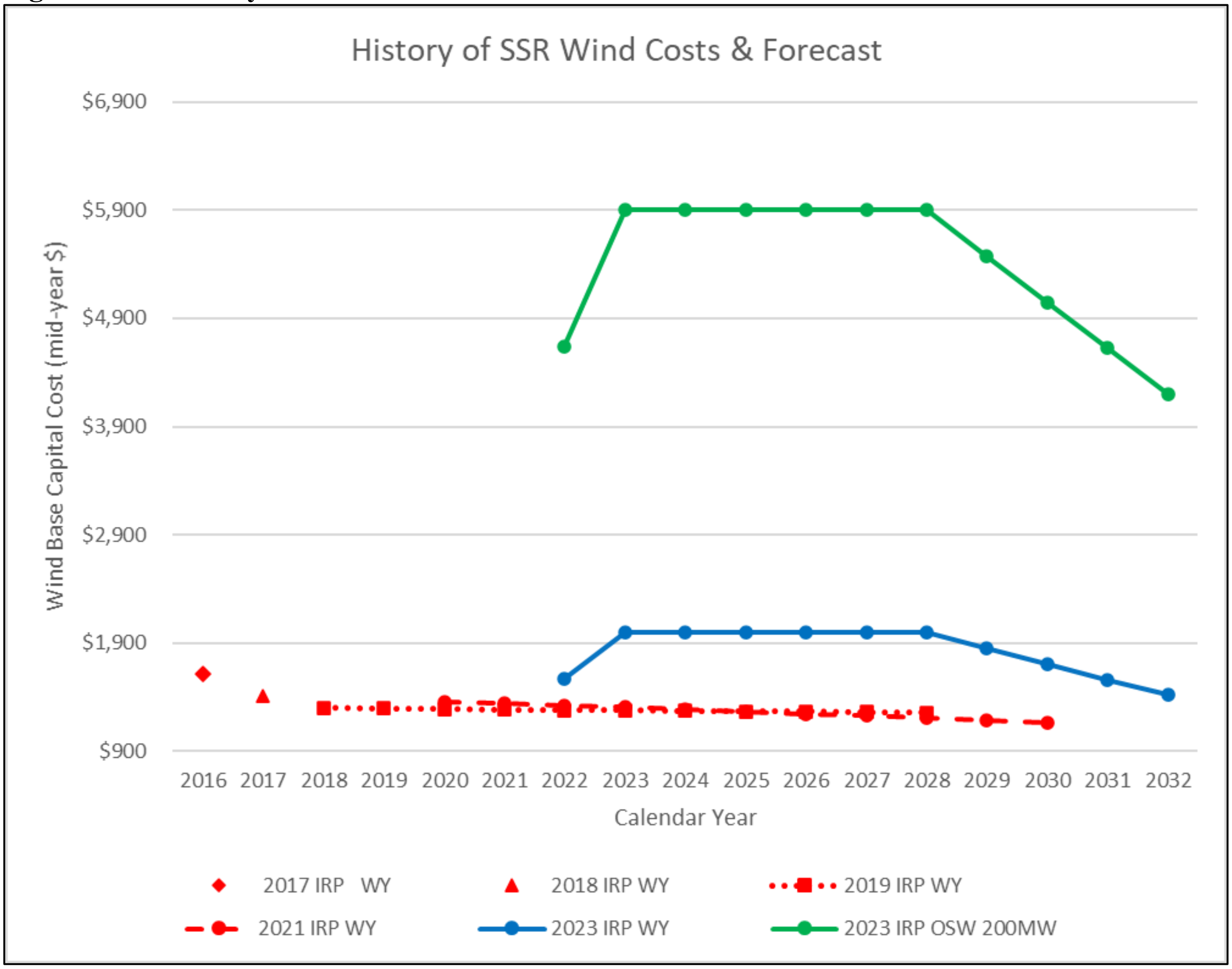
Wind energy has been one of the most cost-effective new generation resources for PacifiCorp's customers in recent IRPs and was the largest source of new resource commitments in PacifiCorp's recently completed 2020 All-Source Request for Proposals. PacifiCorp has also committed to repower two existing wind sites, combining prime geographic locations with existing transmission infrastructure with updated technology. The wind market knowledge PacifiCorp gained and continues to gain from these wind projects has been combined with the information in the WSP Assessment to inform the wind costs in the 2023 IRP.

The WSP Assessment uses a 200 MW project size that can be realized within most wind development areas in PacifiCorp's service territory and large enough to achieve economies of scale. The net capacity factors for onshore wind generating facilities in the states of Idaho, Oregon, Utah, Washington, and Wyoming reflect strong wind resources that are achievable within or near PacifiCorp's service areas. Generic project locations were selected by the company based on viable wind project locations where there are favorable wind profiles. All wind resources are specified in 200 MW blocks, but the model can choose multiple blocks or a fractional amount of a block.

Offshore Wind

PacifiCorp added offshore wind as a resource in the SSR for the 2023 IRP. A 200 MW option is included for comparison to the onshore 200 MW size, and for potential modeling in a scenario without extensive onshore transmission upgrades. A 1,000 MW option is included for modeling in a potential scenario which would require extensive onshore transmission system upgrades. The solid green line in Figure 7.4 shows the higher capital cost of offshore wind versus onshore wind. The cost difference between the 200 MW and 1,000 MW resource options is imperceivable on this graph and does not include on-shore transmission upgrades as those costs are location dependent. Offshore wind holds the promise of high production capacity but faces various risks and costs that are higher than onshore wind projects. The most promising offshore wind regimes are located approximately 10 to 20 miles from the coast and will require underwater electric transmission lines to connect to the shore. New offshore wind projects will have to bear the cost of underwater transmission lines and any land-based transmission upgrades that are required to interconnect the project to the grid. Offshore wind turbines along the Pacific coast will need to be built on floating bases due to water depths that are hundreds of meters deep, as compared to offshore wind developments in shallower waters along the Atlantic coast. Floating offshore wind turbines are much less common than seabed-mounted offshore wind turbines that can be built in ocean waters up to 60 meters deep. Interest in offshore wind along the Pacific coast has increased during the past IRP cycle and the advancement of two areas for offshore wind development along the coast of California by the US Department of the Interior was a significant step forward in the development process.

Figure 7.4 – History of SSR Wind Costs & Forecast



Geothermal

Geothermal resources can produce base-load energy and have high reliability and availability. However, geothermal resources have significantly higher development costs and exploration risks than other renewable technologies such as wind and solar. PacifiCorp has commissioned several studies of geothermal options during the past ten plus years to determine if additional sources of production can be added to the company's generation portfolio in a cost-effective manner. A 2010 study commissioned by PacifiCorp and completed by Black & Veatch focused on geothermal projects near PacifiCorp's service territory that were in advanced phases of development and could demonstrate commercial viability. PacifiCorp commissioned Black & Veatch to perform additional analysis of geothermal projects in the early stages of development and a report was issued in 2012. An evaluation of the PacifiCorp's Roosevelt Hot Springs geothermal resource was commissioned in 2013. The geothermal costs in the 2023 supply side resource option were developed by WSP's geothermal experts in New Zealand and reflect some potential cost reductions from recent and on-going advancements in geothermal resource exploration and development.

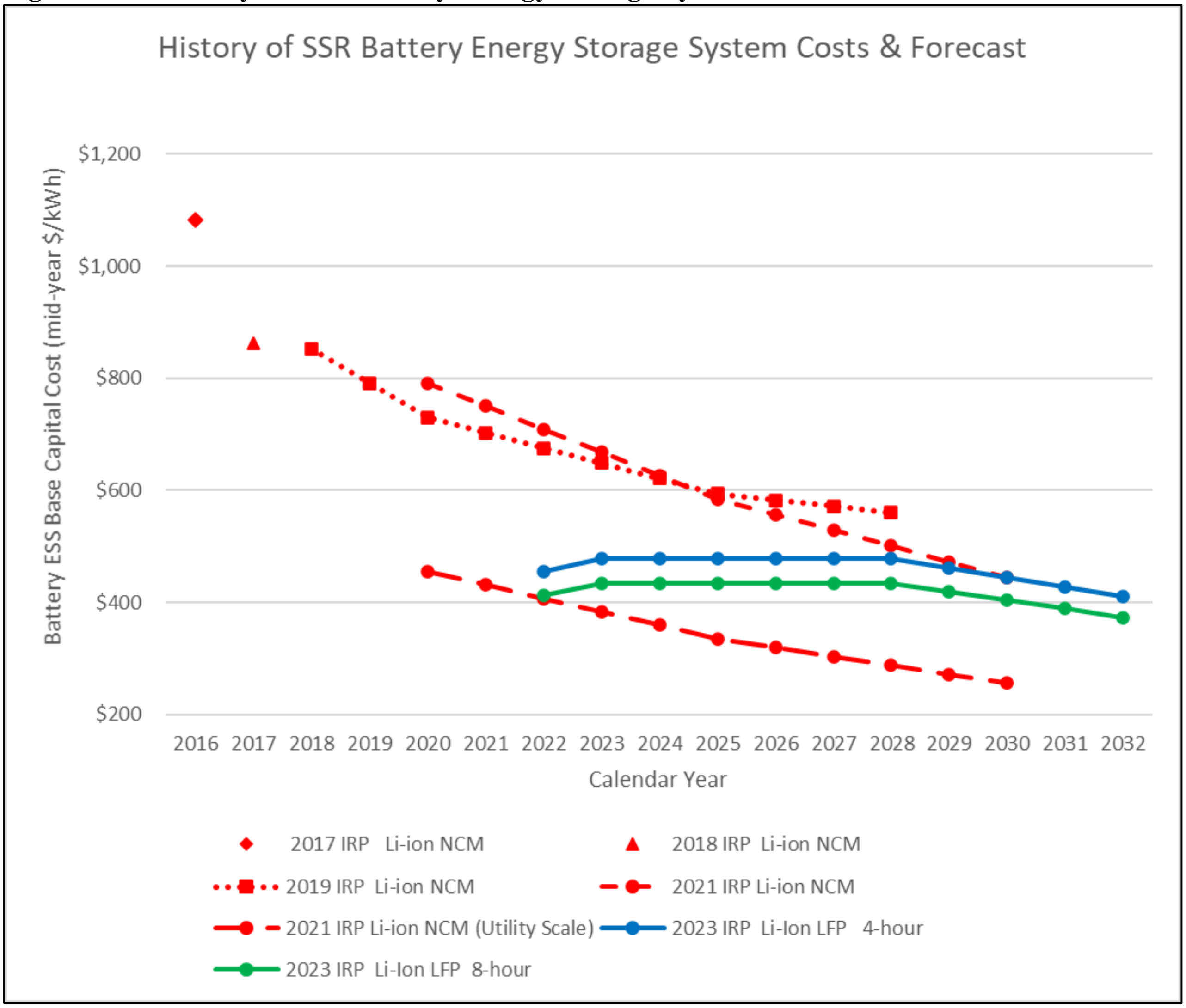
The cost recovery mechanisms currently available to PacifiCorp as a regulated electric utility are not compatible with the inherent risks associated with the development of geothermal resources for power generation. The primary risks of geothermal development are dry holes, well integrity and insufficient resource adequacy (flow, temperature, and pressure). These risks cannot be fully quantified until wells are drilled and completed. The cost to validate total production capability of a geothermal resource can be as high as 35 percent of total project costs. Exploration test wells typically cost between $500,000 and $1.5 million per well. Full production and injection wells cost between $4-5 million per well. Variations in the permeability of subsurface materials can determine whether wells in proximity are commercially viable, lacking in pressure or temperature, or completely dry with no interconnectivity to a geothermal resource. As a regulated utility subject to the public utility commissions of six states, PacifiCorp is not compensated nor incentivized to engage in these inherently risky development efforts.

To mitigate the financial risks of geothermal development, PacifiCorp would use an RFP process to obtain market proposals for geothermal power purchase agreements or build-own-transfer project agreement structures. Geothermal developers, external to PacifiCorp, have the flexibility to structure project pricing to include all development risks. Through an RFP process, PacifiCorp could choose the geothermal project with the lowest cost offered by the market and avoid considerable risk for the company and its customers. Several geothermal projects submitted proposals in response to the 2016 Oregon Renewables RFP, but none of the geothermal projects were selected by PacifiCorp. In the event PacifiCorp identifies a geothermal asset that appears to be economically attractive but also determines that there is a significant possibility of development risk that the market will not economically absorb, PacifiCorp may approach state regulators with estimates of resource development costs and risks associated to obtain approval for a mechanism to address risks such as dry holes. Because public utility commissions typically do not allow recovery of expenditures which do not result in a direct benefit to customers, and at least one state has a statute that precludes cost recovery of any asset that is not considered to be “used and useful,” obtaining a mechanism to recover geothermal development costs may be difficult.

Energy Storage

The WSP Assessment discusses four energy storage resource options: 1) lithium-ion batteries, 2) flow batteries, 3) gravity batteries (other than pumped hydro), and 4) compressed air energy storage (CAES). Lithium-ion battery storage was also considered in combination with solar and wind. Due to on-going confidential discussions with pumped hydro project developers, pump hydro was simplified in the 2023 IRP with a standard 400 MW resource for all locations. The details were developed internally and are intended to represent a reasonable option within the IRP modeling, while maintaining neutrality among the specific projects within PacifiCorp territory. PacifiCorp worked with both WSP and Renewable Energy Storage Company, LLC (a developer of an adiabatic CAES project within PacifiCorp’s territory. The costs appear to be competitive with the CAES option modeled in the 2021 IRP. No forecasts have been used for pumped hydro and CAES. Both technologies are expected to have a flat forecast escalating at the standard inflation rate used in the IRP modeling.. Figure 7.5 shows a history of capital costs on a per MWh *energy capacity* basis (note that similar graphs for other resources are on a per kW *power capacity* basis) and forecasts used in the SSR for Li-Ion battery resources. The solid lines indicate the 2022 price and forecast at the 200 MW scale considered for the 2023 IRP at 4-hour duration in blue and an 8-hour duration in green. The 200 MW capacity is in an increase from the 50 MW capacity used in the 2021 IRP, as projects at the 200 MW scale are being proposed in RFP’s. Like solar project costs, battery project costs appear to have increased due to inflation and increased demand, but do not seem to have been significantly impacted by trade restrictions.

Figure 7.5 – History of SSR Battery Energy Storage System Costs & Forecast



PacifiCorp and its Berkshire Hathaway Energy affiliates continuously monitor and evaluate technical developments in the utility power industry, including energy storage technologies (lithium-ion and flow batteries, pumped storage hydro and hybrid energy-storage solutions), nuclear and carbon capture technologies. With the ever-advancing technological developments, market conditions, and regulatory environment, it is critical that PacifiCorp understand when developing technologies and other opportunities become sufficiently established in the marketplace that they can be implemented with minimal risk to PacifiCorp's system customers.

PacifiCorp also leverages the broader Berkshire Hathaway Energy platform of companies including NV Energy and MidAmerican Energy to collaborate and share experiences and lessons learned regarding battery energy storage technology and capturing the value of energy storage. NV Energy has been a leader in battery storage.

In addition to leveraging the experience of its peer utilities, PacifiCorp has engaged the expertise of market-leading 3rd party technical experts including WSP, Black & Veatch, Power Engineers, DNV, FlexGen, Tesla, Powin, ESS, Lion, Form, Uni Energy Technologies and other leading battery consultants and suppliers to develop its proxy resource assumptions, develop its procurement specifications, evaluate bidders, develop benchmark projects, and design and construct utility-owned transmission and distribution facilities.

In 2021, PacifiCorp's IRP process identified over 6,000 megawatts of battery storage as a part of its least-cost portfolio through 2040. Leading up to the inclusion of battery storage in the 2022 All-Source Request for Proposals, PacifiCorp updated the standard specifications, and system control schemes for battery storage facilities. In the request for proposal, PacifiCorp outlined battery storage use cases and required functionality to ensure battery storage proposal value was captured through battery energy storage bids. Finally, PacifiCorp engaged outside legal expertise in negotiating contracting terms and conditions with short-listed bidders in the 2020 all-source RFP to further mitigate delivery risk to its customers.

PacifiCorp procurement and operational experience with battery storage projects

PacifiCorp completed the Panguitch Solar and Battery Storage project in Utah in 2020 as a utility-owned and operated transmission and distribution upgrade deferral project. In 2019-2020, PacifiCorp partnered with Sonnen, Inc. and the Wasatch Group to complete The Soleil Lofts Residential Apartment Project, a network of solar powered battery storage systems for the benefit of the apartment community and PacifiCorp's customers. PacifiCorp continues work towards completing the development and design for a project in Oregon to install a battery storage project at the Oregon Institute of Technology in Klamath Falls, which is scheduled for completion in 2023. These three projects demonstrate the capability and validate the value battery storage provides to the electrical grid through peak shifting to defer the cost to upgrade regional transmission and distribution lines, and other energy storage value cases. PacifiCorp had complete turnkey responsibility for the Panguitch Solar and Battery Storage facility and will similarly be responsible for the Oregon Institute of Technology facility. The Soleil Lofts facilities were developed, constructed and owned by a 3rd party, but are being dispatched by PacifiCorp's Energy Supply Management Group for the benefit of PacifiCorp's system. Leveraging lessons learned from the Soleil Lofts project, PacifiCorp's Wattsmart program added batteries to its Savings & Energy Choices.

The 2020 and 2022 All Source (AS) Requests for Proposal (RFP) have requested and received multiple utility scale battery energy storage system (BESS) bids. For the 2020 AS RFP, no standalone battery storage contracts were executed. For the 2022 AS RFP the PacifiCorp benchmark team has prepared and submitted four standalone BESS and four solar-plus-battery projects with over 1,200 MW of power capacity. The RFP evaluation team has received third party standalone BESS and solar-plus-battery bids from multiple counterparties representing more than 5,000 MW of storage capacity.

Panguitch Solar and Battery Storage Project

To correct voltage issues experienced during peak loading conditions on a portion of PacifiCorp's system in southern Utah, a stationary battery system and photovoltaic solar array was installed on a distribution circuit out of the Panguitch substation located in Garfield County, Utah. This project will alleviate peak loading on the power transformer, improve voltage conditions, and defer costs associated with upgrading the upstream 69-kV sub-transmission system under a traditional poles and wires build-out. The Panguitch project was a 650-kilowatt photovoltaic solar field and one megawatt, five-hour battery system in central Utah. PacifiCorp with Black & Veatch and battery supplier FlexGen developed multiple operating modes to demonstrate the full range and capabilities of 684 Samsung lithium-ion batteries and how different control modes affect energy system operation.

The Utah Public Service Commission approved the Panguitch battery storage project (1 MW, 5 MWh) under the Sustainable Transportation and Energy Plan/Utah Innovative Technologies (STEP/UIT) program December 29, 2016. The solar photovoltaic component (650 kW) of the project was separately funded by the company's Blue Sky program. PacifiCorp completed the purchase of a ten-acre project site in October 2017. Construction began in July 2019 and was completed in late 2019. Commercial operations began in 2020.

Since commercial operations began, the company has worked with the battery provider to refine the control algorithms to enable charging of the battery only from the on-site solar generation facility. The company is currently collecting solar and battery charge/discharge data from the site to further optimize operational performance.

Soleil Lofts Residential Apartment Project

Soleil Lofts, located in Herriman, Utah is an all-electric, net-zero development, designed to generate as much electricity as it uses through rooftop solar panels backed up with battery storage. PacifiCorp collaborated with the Soleil Lofts residential apartment project to develop a behind the meter application of battery systems. This project is the largest utility-managed residential battery demand response solution in the United States. PacifiCorp with Sonnen, Inc. and the Wasatch Group completed a network of solar powered battery storage systems for the benefit of the apartment community and PacifiCorp's customers. The project features over 630 individual Sonnen ecoLinx batteries, totaling 12.6 MWh of solar energy storage that is managed by PacifiCorp. The batteries provide emergency back-up power, daily management of peak energy use, and demand response for the overall management of the electric grid and demonstrating a way to expand residential renewable power capacity.

Wattsmart Battery Program

This innovative program is intended to solve some of today's challenges to help create a healthier environment and use renewable energy effectively while setting the foundation to evolve with technology and customer needs as we transition to a more renewable energy future. It is a voluntary program available to all Rocky Mountain Power customers who purchase and install a qualifying battery and who meet all program requirements. Program benefits include an upfront enrollment incentive plus ongoing bill credits while enabling back-up power. Qualified batteries will be connected to the electric grid through a customer generation meter, allowing Rocky Mountain Power to manage the battery to keep the grid reliable, resilient and secure. The program will evolve based on the lessons learned and the need to ensure sustainability for the long term. More information is available at rockymountainpower.net/battery.

Oregon Institute of Technology

Oregon House Bill (HB) 2193, passed in June of 2015 directed electric companies in Oregon to identify and evaluate potential energy storage technologies. PacifiCorp has commenced a project to engineer, design, procure, interconnect, and commission a 2 MW (6 MWh) battery storage project on the campus of the Oregon Institute of Technology ("OIT") in Klamath Falls, Oregon. Design and procurement activities are underway in parallel with the generation interconnection review process. The project is expected to go into service in 2023. PacifiCorp has contracted Power Engineers as the Engineer of Record, and has contracted with POWIN for the

BESS supply. Once the design is complete a construction contractor will be selected via competitive bid. PacifiCorp's engineering and management team are also working with OIT to provide a student learning experience once the system is operational.

Outside Engineering Support for Battery Storage Procurement and Operations

In preparation for the 2020 and 2022 all-source requests for proposal which resulted from the resource need action items in the 2019 and 2021 IRP processes, PacifiCorp engaged WSP to 1) develop preferred use case and technical specifications for collocated and stand-alone storage resource bids, 2) evaluate the technical bid responses, 3) update the generating-resource power purchase agreements to include battery storage terms and conditions and relevant exhibits needed for a collocated resource and storage power purchase agreement, and 4) provide cost and technical information and reports for renewable resources included in the 2023 IRP,.

WSP is a globally recognized professional services firm with a 130-year history. WSP's primary inputs have been in a supporting role, assisting in the development of revised specifications for wind and solar farm equipment and installations including accompanying battery storage facilities. Specific to battery storage, WSP has been influential in assisting PacifiCorp in the development of Li-battery specifications and has participated in the development of operating and contractual parameters that will become part of our revised power purchase agreement contract template in the 2020AS RFP contracting process.

PacifiCorp has actively monitored developments in battery storage since 2009 with support through the broader Berkshire Hathaway Energy platform of companies including NV Energy and MidAmerican Energy and through the engagement of market-leading companies like WSP, Black & Veatch, Burns & McDonnel, DNV, Power Engineers, FlexGen, Tesla, Sonnen, ESS Inc., Lion Energy, and Uni Energy Technologies. Further, PacifiCorp is actively evaluating and pursuing new control systems that will both integrate and optimize battery storage, and other electronically controlled distributed assets, to further assure both maximum customer benefit and improved system flexibility and stability for years to come. With each new battery storage resource added to our system, we gain additional depth and experience that we then apply to the next cycle of integrated resource planning and subsequent resource procurement.

Natural Gas

Natural gas-fueled generating resources offer several important services that support the safe and reliable operation of the energy grid in an economic manner. They include technologies that are capable of providing firming, peaking, intermediate and base generation.

A variety of natural gas-fueled generating resources are included in the SSR. The variety of natural gas resources were selected to provide for generating performance and services essential to safe and reliable operation of the energy grid. Performance, cost and operating characteristics for each resource were provided at elevations of 1,500, 3,000, 5,050 and 6,500 feet above mean sea level, representative of geographic areas in which the resource could be located. Performance, cost and operating characteristics were also provided at zero feet above mean sea level and 59 °F (ISO conditions) as a reference. The essential services provided by the resource are firming for variable energy resources, intermediate and base generation.

Two simple cycle combustion turbine options, and 3 simple cycle with hydrogen options, could provide peaking generating services. Peaking generating services require the ability to start and reach near full output in less than ten minutes. Peaking generating services also require the ability in increase (ramp up) and decrease (ramp down) very quickly in response to sudden changes in power demand as well as increases and decreases in production from intermittent power sources. Peaking generation provide the ability to meet peak power demand that exceed the capacity of intermediate and base generation. Peak generation also provide reserves to meet system upsets.

A combined cycle combustion turbine option could provide firming, intermediate and base generating service. Firming generating service requires resources that can increase and decrease generation to replace decreases and increases in generation from variable energy resources. Intermediate generating service requires resources that can efficiently operate at production rates well below full production in compliance with air emissions regulations for long periods of time. Intermediate generating service also require the ability to change production rates quickly. Intermediate generation services provide power demand that is greater than base load and lower than peak demands. Base generating service requires a resource that can operate at full production for long periods of time. Base generation provides for the minimum level of power demand over a day or longer period at a low cost.

Options for intermediate and base generation were based on the "J" size represented by the GE HA.02. Each engine was arranged in a one combustion turbine to one steam turbine (1x1) configuration. Installation of oxidation catalysts for CO control and SCR systems for NOx control is expected. All the combined cycle options included dry cooling allowing them to be located in areas with water resource concerns.

Duct Firing (DF) of the combined cycle is shown in the SSR table. Duct firing is a low-cost option to add peaking capability to a combined cycle at relatively high efficiency and also a mechanism to recover lost power generation capability at high ambient temperatures. In practice the amount of duct firing is a design consideration which is selected during the development of combined cycle generating facilities. In the 2023 IRP, the basic "J" turbines are assumed to be sized such that adding duct firing would result in a negligible capital cost increase, therefore duct firing was included in the combined cycle costs shown in the SSR table, but listed on a separate line to show the distinct operating characteristics it offers.

While equipment provided by specific manufacturers were used to for cost-and-performance information in the SSR table, more than one manufacturer produces these types of equipment. The costs and performance used here is representative of the cost and performance that would be expected from any of the manufacturers. Final selection of a manufacturer's equipment would be made based on a bid process.

Coal

Coal resources in the 2023 SSR table include three supercritical pulverized coal (PC) Carbon Capture, Utilization and Storage (CCUS) retrofit options located in Wyoming. The standard design technology for PC boilers is supercritical technology (compared to subcritical). Supercritical technology is generally more cost-effective because it has a higher efficiency (resulting in a lower overall emissions intensity), has better load following capability, faster ramp rates, uses less water and requires less steel for construction. As such, there is a greater competitive marketplace for large supercritical boilers than for subcritical boilers, and large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. A new coal-fueled generating facility would be subject to carbon dioxide emissions limits (1,400 lbs per megawatt-hour gross) under the Federal New Source Performance Standards (NSPS) for Greenhouse Gases (GHG). These emission limits are only achievable if a coal-fueled generating facility is equipped with CCUS technology;

however, this imposes a significant cost for both new and existing coal resources. Based on this requirement, only CCUS retrofit options for coal resources are included in the SSR table. The capital and O&M costs for a CCUS retrofit were updated by either escalating corresponding costs used in the 2021 IRP or updating information from existing carbon capture facilities, relevant studies and/or CCUS developers.

Carbon Capture, Utilization and Storage

There are a limited number of commercial-scale carbon capture projects in operation around the world. Most have been installed in conjunction with a planned carbon dioxide end use of injection for EOR. There are only two major utility-scale CCUS retrofit projects on coal plants in North America that have been operated commercially. SaskPower's Boundary Dam Power Station Unit 3 (115 MW net), located in Saskatchewan, Canada, was retrofitted with an amine-based carbon capture system and entered commercial operation in October 2014. The captured carbon dioxide is piped 41 miles to the Weyburn field to be used for EOR. Any carbon dioxide not used for EOR is sequestered at the Aquistore research project. The total cost of the project was approximately $1.24 billion (including approximately $200 million through federal grants). In July 2016, the plant reached a major milestone when it demonstrated that over 1,100,000 tons of carbon dioxide had been captured.

NRG Energy installed a 240 MW equivalent flue gas slipstream amine-based carbon capture system on W.A. Parish Generating Station Unit 8 that went into commercial operation in January 2017. The project, named the Petra Nova Project, was a joint venture between NRG Energy and JX Nippon Oil & Gas Exploration, and cost approximately $1 billion. Approximately $195 million of federal funding in grants was awarded to the project as part of the Clean Coal Power Initiative Program (CCPI), a cost-shared collaboration between the federal government and private industry. The Petra Nova Project included a retrofit of an existing coal-fueled plant using amine-based system and captured approximately 5,200 short tons per day when operating at full capacity.[5] Captured carbon dioxide was transported through an 81-mile pipeline and used for EOR at the West Ranch Oilfield, located on the Gulf Coast of Texas. It is the largest carbon capture retrofit of a pulverized coal plant in the world. The amine-based capture system utilizes Mitsubishi's proprietary KM CDR Process® and uses its KS-1™ amine solvent. Due to low demand for and price of oil in 2020, NRG Energy announced Petra Nova would be placed in a reserve shutdown effective May 1, 2020.[6] In January 2021, the Electric Reliability Council of Texas received a Notification of Suspension of Operations (NSO) for Petra Nova Power.[7] The NSO stated the resource would be mothballed indefinitely as of June 26, 2021.[8]

To address the availability and viability of commercial sequestration near PacifiCorp coal generation resources, three PacifiCorp power plants participated in federally funded research to conduct a Phase I pre-feasibility study, which was awarded in 2016, for carbon capture and storage. A grant from the U.S. Department of Energy (DOE) to the University of Wyoming was used to assess the storage of carbon dioxide in the Rock Springs Uplift, a geologic formation located

[5] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project Final Scientific/Technical Report; March 31, 2020.

[6] Petra Nova status update | NRG Energy

[7] W-A012721-01 Notification of Suspension of Operations (NSO) for Petra Nova Power I LLC (PNPI_GT2) (ercot.com)

[8] A March 2021 notice was issued, moving up the date to suspend operations to June 1, 2021. W-A012721-03 Date of suspension of operations changed - Indefinite Mothball Status of Petra Nova Power I LLC (PNPI_GT2) (ercot.com)

adjacent to the Jim Bridger Plant in southwest Wyoming. Similar funding was allocated to the University of Utah to study the feasibility of long-term carbon dioxide storage in the San Rafael Swell near the Hunter and Huntington plants in central Utah. Both projects showed that geological formations exist near the plants that may support carbon sequestration, though further studies would be required. Neither site was selected by the U.S. DOE for an advanced study in the Phase II of the grant program.

PacifiCorp issued a request for expression of interest to potential CCUS counterparties on September 7, 2018. The request focused on possible deployment of CCUS technologies at PacifiCorp's Dave Johnston generating facility, including utilization of EOR. On February 28, 2019, PacifiCorp received Phase I feasibility studies from three respondent parties. On April 23, 2019, the participants were notified they could opt to progress to a Phase II front-end engineering and design (FEED) study at their discretion. Only one of the parties expressed intent to complete a FEED study. No participants received DOE funds to support Phase II studies. PacifiCorp remains open to evaluate any CCUS project proposal that may arise from these efforts.

As part of its ongoing CCUS evaluation, PacifiCorp issued a new request for expression of interest (REOI) for CCUS on June 29, 2021, to identify and engage with any interested parties to explore the feasibility and design of CCUS facilities to remove carbon dioxide from exhaust gases for PacifiCorp's Wyoming coal-fueled generation, and subsequently utilize and/or sequester all removed carbon dioxide. PacifiCorp received 19 responses from a conglomerate of 60 interested parties.

The Company filed its initial CCUS application for compliance with Wyoming's House Bill 200 and corresponding rules on March 31, 2022. The initial application included a feasibility analysis of CCUS technologies and the Company's coal-fired generation units in Wyoming. The analysis identified Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 as potentially suitable candidates for CCUS and that the Company would further analyze these units in a subsequent request for proposal (RFP) process. The initial application also identified amine solvent based CCUS technology as being the only viable technology to date with the maturity level to be deployed at the scale required by Wyoming's House Bill 200 and administrative rules. The Company issued two CCUS RFPs, one for Jim Bridger Units 3 and/or 4, and one for Dave Johnston Unit 4 on November 1, 2022. Proposals were due March 7, 2023, and PacifiCorp is evaluating information received.

The Commission approved the Company's initial application on November 29, 2022 and directed the Company to consider CCUS proposals based on alternative technology and for alternative sites (Alternative Proposals), update the Company's initial application no later than March 31, 2023, and submit a final plan by March 31, 2024. To comply with Commission directives and to prevent delay to the RFP that was initiated before deliberations occurred, PacifiCorp re-engaged with interested parties on February 24, 2023, requesting information for any advancements to technology, updated cost information, updated partnerships, additional funds for CCUS projects (from the Department of Energy (DOE) or otherwise), any updated proposed CCUS structure(s), or any other information relevant to any of the Company's Wyoming coal units regarding CCUS. Responses were submitted on March 24, 2023, and are being reviewed. The Company also submitted its update to the initial application on March 31, 2023.

Nuclear

PacifiCorp's 2023 IRP includes the Natrium^{TM} advanced nuclear demonstration project: a molten sodium-cooled nuclear reactor paired with a molten salt thermal energy storage tank. Heat from the reactor and the molten salt energy storage is used to generate power through a single steam turbine.

At this time, the specific cost and performance assumptions for the Natrium^{TM} advanced nuclear demonstration project are confidential and are not summarized in the SSR. The demonstration project has three primary elements: a nuclear reactor that produces heat, a molten salt tank to store heat, and a steam generator to convert heat to electricity. Operating characteristics of this facility are summarized as follows:

- 345 MW of baseload energy production at a 92.5% capacity factor
- Maximum output of 500 MW
- Minimum output of 100 MW
- A ramp rate of approximately 40 MW per minute from min to max
- Molten salt storage supports maximum output of 500 MW for a 5.5-hour duration (max output then drops to 345 MW until output is reduced and more heat can be stored)
- Maximum storage efficiency is 99%

In October 2020, the U.S. Department of Energy (DOE), through its Advanced Reactor Demonstration Program (ARDP), awarded TerraPower $80 million in initial funding to demonstrate the Natrium technology. TerraPower signed the cooperative agreement with DOE in May 2021. To date, Congress has appropriated $160 million for the ARDP and DOE has committed additional funding in the coming years, subject to appropriations.

On June 2, 2021, PacifiCorp announced efforts with TerraPower and the U.S. Department of Energy to advance the Natrium^{TM} demonstration project to be sited at a retiring coal plant near, Kemmerer, Wyoming. More information can be found on the Wyoming Advanced Energy webpage at: wyomingadvancedenergy.com. The project features an advanced nuclear reactor developed by TerraPower and GE Hitachi, represented by a 345 MW sodium-cooled fast nuclear reactor with a molten salt-based energy storage system. The energy storage system can increase the project's output to 500 MW for more than five and a half hours when needed. The technology uses structural advancements that separate and simplify major structures, reducing complexity, cost and construction schedule while delivering safe and reliable electricity. The Natrium^{TM} advanced reactor also has enhanced safety features which take advantage of natural forces that do not require human intervention with the ability to shut down independently, indefinitely if needed.

On October 27, 2022, TerraPower and PacifiCorp announced their undertaking of a joint study to evaluate the feasibility of deploying up to five additional Natrium^{TM} reactor and integrated energy storage systems in the PacifiCorp service territory by 2035. The joint study will evaluate, among other things, the potential for advanced reactors to be located near current fossil-fueled generation sites, enabling PacifiCorp to repurpose existing generation and transmission assets for the benefit of its customers. The location of future Natrium^{TM} plants will be thoroughly explored through this study process, and both companies will engage with local communities before any final sites are selected.

Congress and the Department of Energy under the Biden Administration have taken proactive steps to continue to support the deployment of advanced nuclear technologies as part of a suite of solutions aimed at achieving carbon-free goals. With the passage of the Inflation Reduction Act, the bipartisan Infrastructure Investment and Jobs Act, and recent studies on the opportunities of a coal-to-nuclear energy transition, TerraPower and PacifiCorp remain committed to bringing the Natrium™ technology to market and providing reliability and stability to the grid as well as to energy producing communities.

NuScale is developing an advanced reactor design in the Small Modular Reactor (SMR) category. Although it is an FOAK technology, the design has inherent safety features which support reduced capital costs and operating cost estimates. Prior to 2022 PacifiCorp had a seat on the NuScale advisory board; however, PacifiCorp has no monetary interest in NuScale or the SMR project being developed for the Idaho National Lab site. PacifiCorp updated NuScale pricing for the 2023 IRP. Details of NuScale's SMR can be found at www.nuscalepower.com.

Demand-Side Resources

Resource Options and Attributes

Source of Demand-Side Management Resource Data

PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2023-2042, which provided DSM resource opportunity estimates for the 2023 IRP. The study was conducted by Applied Energy Group (AEG) on behalf of the company. The CPA provided a broad estimate of the size, type, location and cost of demand-side resources.[9] For the purpose of integrated resource planning, the DSM information from the CPA was converted into supply curves by type of resource (i.e. energy-based energy efficiency and demand response) for modeling against competing supply-side alternatives.

Demand-Side Management Supply Curves

DSM resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (e.g. products and quantities) based on each resource's competitiveness against alternative resource options. Due to the timing of the 2023 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2023 DSM program acquisition targets. To ensure that the 2023 IRP analysis is consistent with existing and planned demand response and energy efficiency acquisition levels (i.e., Class 1 & 2 DSM), expected DSM savings in each state were fixed for calendar year 2023. In 2024 and 2025 energy efficiency resources were optimized to reflect ongoing program experience and knowledge of current market conditions and timing challenges, to develop near terms levels of selected acquisition.

As with supply-side resources, the development of DSM supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to DSM curves include:

[9] The 2023 Conservation Potential Study is available on PacifiCorp's demand-side management web page. www.pacificorp.com/energy/integrated-resource-plan/support.html.

- Resource quantities available in each year either in terms of megawatts or megawatt-hours, recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year of the planning period;
- Persistence of resource savings (e.g., energy efficiency equipment measure lives);
- Seasonal availability and hours available (e.g., irrigation load control programs);
- The hourly shape of the resource (e.g., load shape of the resource); and
- Levelized resource costs (e.g., dollars per kilowatt-hour per year for energy efficiency, or dollars per megawatt over the resource's life for demand response resources).

Once developed, DSM supply curves are treated like discrete supply-side resources in the IRP modeling environment.

Demand Response: DSM Capacity Supply Curves

The potential and costs for demand response resources were provided at the state level, with impacts specified separately for summer and winter peak periods. Prior to 2023, PacifiCorp has launched and expanded a number of demand response programs to acquire resource needs identified in the 2021 IRP update. Several demand response resources characterized as potential demand response resources in the previous IRP are now considered existing or planned demand response resources which will be effective in 2023.

Table 7.8 – Demand Response Existing and Planned Programs

Product	State	Existing or Planned Offering
Res – HVAC DLC	UT	Existing
Res – Water Heater DLC	OR, WA	Planned
Res – Smart Thermostat	OR, WA	Planned
Res – Grid Interactive Water Heaters	OR, WA	Planned
Res –Battery DLC	ID, UT	Existing
C&I –Battery DLC	ID, UT	Existing
C&I – Third Party	OR, WA, UT	Existing
C&I – Third Party	ID	Planned
Ag – Irrigation DLC	UT, ID, OR, WA	Existing

Table 7.5 and Table 7.6 show the summary level demand response resource supply curve information, by control area. For additional detail on demand response resource assumptions used to develop these supply curves, see Volume 2 of the 2023 CPA.[10] Potential shown is incremental to the existing DSM resources identified in Table 7.5. For existing program offerings, it is assumed that the PacifiCorp could begin acquiring incremental potential in 2023. For resources representing expanded product offerings, it is assumed PacifiCorp could begin acquiring potential in 2024. New program offerings are assumed to be available in 2025 accounting for the time required for program design, regulatory approval, vendor selection, procurement and implementation.

[10] The CPA can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

Table 7.5 – Demand Response Program Attributes West Control Area[11],*

Product	Summer		Winter	
	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)
Res - EV DLC	46	$381	46	$381
Res – DLC of Smart Home	0.3	$700	1	$354
Res – HVAC DLC	53	$135	94	$73
Res – Pool Pump DLC	0.4	$721	0.1	$1900
Res – Water Heater DLC	35	$139	52	$93
Res – Smart Thermostat	42	$13	38	$15
Res – Grid Interactive Water Heaters	93	$76	135	$52
Battery DLC	4	$33	4	$28
C&I – Third Party	27	$30	42	$35
Ag – Irrigation DLC	24	$23	0	$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

Table 7.6 – Demand Response Program Attributes East Control Area[12],*

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
Res - EV DLC	85	$408	85	$408
Res – DLC of Smart Home	1	$814	1	$412
Res – HVAC DLC	119	$49	117	$254
Res – Pool Pump DLC	0.4	$812	0.2	$2141
Res – Water Heater DLC	65	$182	97	$122
Res – Smart Thermostat	73	$19	63	$22
Res – Grid Interactive Water Heaters	5	$131	8	$90
Battery DLC	74	$33	54	$51
C&I – Third Party	43	$40	44	$40
Ag – Irrigation DLC	56	$29	0	$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

Energy Efficiency DSM, Energy Supply Curves

The 2023 CPA provided the information to fully assess the potential contribution from DSM energy efficiency resources over the IRP planning horizon. The CPA analysis accounts for known changes in building codes, advancing equipment efficiency standards, market transformation,

[11] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

[12] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g., cost-effectiveness criteria).

DSM energy efficiency resource potential was assessed by state down to the individual measure and building levels (e.g., specific appliances, motors, lighting configurations for residential buildings, and small offices). The CPA provided DSM energy efficiency resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming[13]
- **Measure:**
  - 110 residential measures
  - 143 commercial measures
  - 96 industrial measures
  - 22 irrigation measures

- **Facility type:**[14]
  - 18 residential facility types
  - 28 commercial facility types
  - 30 industrial facility types
  - Two irrigation facility type

The 2023 CPA levelized total resource costs over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Costs include measure costs and a state-specific adder for program administrative costs for all states except Utah and Idaho. Consistent with regulatory mandates, Utah and Idaho DSM energy efficiency resource costs were levelized using utility costs instead of total resource costs (i.e. incentive and a state specific adder for program administration costs).

The technical potential for all DSM energy efficiency resources across all states except Oregon over the twenty-year CPA planning horizon totaled approximately 16 million MWh.[15] The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (i.e. technical achievable potential). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 13.3 million MWh for all five states. The technical achievable potential for all six states for modeling consideration is 16.8 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures by building type and state generated almost 75,000 separate permutations or distinct measures that

[13] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.
[14] Facility type includes such attributes as existing or new construction, single or multi-family, and income level for the residential sector. Facility types represent a combination of market segment and vintage and are more fully described in in the Analysis Approach in Volume 1, of the 2023 CPA.
[15] The identified technical potential represents the cumulative impact of DSM measure installations in the 20th year of the study period for California, Idaho, Washington, Wyoming, and Utah. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period. ETO provides PacifiCorp with technical achievable potential.

could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs and net cost of capacity to reduce the number of combinations to a more manageable number.

Bundle development began with the energy efficiency technical potential identified by the 2021 CPA. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 20-year planning horizon. Consistent with the Northwest Power and Conservation Council's achievability assumptions in the 2021 Power Plan as, which typically assume that 85% of the technical potential could be acquired over the 20-year period.[16]

For Oregon, the company does not assess potential for the Energy Trust of Oregon (ETO). Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the DSM energy efficiency supply curves used in the development of the 2023 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp's six states.

Twenty-seven cost bundles, with a separate bundle reserved for home energy reports, were available across six states (including Oregon), which equates to 162 DSM energy efficiency resource supply curves. Table 7.7 shows the 20-year MWh potential for DSM energy efficiency net cost of capacity bundle categorization.

Bundles are classified based on their measure's temperature dependency, as either heating or cooling. A measure is considered temperature dependent if at least 25% of annual kWh savings are derived from temperature dependent end-uses. Measures that have both heating and cooling savings are classified based on whichever has greater volume. Measures that are not temperature dependent, such as lighting, are classified based on whichever season (summer or winter) the measure has a greater capacity contribution. Measures are then ranked based on their net cost of capacity ($/kw-yr) and assigned to a bundle with measures of a similar net cost. There is little need to differentiate bundles that will provide value in nearly all conditions. Measures with a net cost less or equal to zero have energy benefits that exceed their costs, such that their capacity value (reliability benefits) are "free". These measures are assigned to a zero-cost temperature-sensitive bin or a zero-cost non-temperature sensitive bin, which together comprise roughly half of all potential. For non-zero cost measures, roughly equal volumes are distributed among the remaining bundles of heating, cooling, summer, or winter measures. The number of each type of bundle varies by state depending on the potential and load profile used in each state.

[16] The Northwest's achievability assumptions include savings realized through improved codes and standards and market transformation, and thus, applying them to identified technical potential represents an aggressive view of what could be achieved through utility DSM programs.

Table 7.7 – 2042 Total Cumulative Energy Efficiency Potential by Cost Bundle Category (MWh)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
Cooling Measures	27,058	89,984	435,590	2,191,500	138,834	203,854
Heating Measures	24,393	119,582	697,503	1,063,751	162,002	79,231
Summer Measures	11,928	20,354	0	448	5,112	1,559
Winter Measures	59,371	65,660	579,073	842,274	285,520	348,928
Zero Cost Temperature Dependent Measures	11,186	58,479	353,995	1,167,754	76,941	95,802
Zero Cost Non-Temperature Dependent Measures	35,105	338,878	1,303,580	4,581,945	455,591	823,909

Cost credits afforded to DSM energy efficiency resources include the following:

- A state-specific transmission and distribution investment deferral cost credit (Table 7.8)
- Stochastic risk reduction credit of $2.25/MWh[17]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[18]

Table 7.8 – State-specific Transmission and Distribution Credits

State	Transmission Deferral Value ($/KW-year)	Distribution Deferral Value ($/KW-year)	Total
California	$5.09	$8.38	$13.47
Oregon	$5.09	$10.46	$15.55
Washington	$5.09	$10.69	$15.78
Idaho	$5.09	$12.57	$17.66
Utah	$5.09	$12.90	$17.99
Wyoming	$5.09	$5.76	$10.85

PacifiCorp relies on simulated load shapes tied to weather stations in PacifiCorp's service territory. Weather is a major driver of PacifiCorp's load and in any given month weather results in a range of high and low load conditions. Weather also impacts the hourly timing of energy efficiency savings particularly for measures that are weather dependent. For the 2023 IRP, PacifiCorp chose to reshape daily energy efficiency volumes to better align with seasonal variations in the load forecast. The highest demand for temperature-sensitive end use loads is expected to occur at the time of the winter and summer peaks in PacifiCorp's service territory. For temperature dependent measures, the highest daily simulated savings were mapped to the highest to lowest load days to align with the load forecast. To capture the time-varying impacts of energy efficiency resources,

[17] PacifiCorp developed this credit from two sets of production dispatch simulations of a given resource portfolio, and each set has two runs with and without DSM. One simulation is on deterministic basis and another on stochastic basis. Differences in production costs between the two sets of simulations determine the dollar per MWh stochastic risk reduction credit.
[18] The formula for calculating the $/MWh Power Act credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

each bundle uses an annual 8,760 hourly load shape specifying the portion of the maximum capacity available in any hour of the year. These shapes are created by spreading measure-level annual energy savings over 8,760 load shapes, differentiated by state, sector, market segment, and end use accounting for the hourly variance of energy efficiency impacts by measure. These hourly impacts are then aggregated for all measures in each bundle to create a single weighted average load shape for that bundle.

Distribution Efficiency

PacifiCorp continues to develop its CYME CYMDIST® (power flow software) investment in ways that improve engineering response time and, indirectly, distribution system efficiency. In the last biennial period, more than 300 large (Level 2 and Level 3) distributed energy resource (DER) applications were studied in CYME. This resulted in more than 29 MW (nameplate) of approved private generation across the company. Any energy savings resulting from these approvals across the service territory has not been determined.

These distribution energy efficiency activities were not modeled as potential resources in this IRP.

Transmission Resources

In developing resource portfolios for the 2023 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the company cover short positions.

FOTs are proxy resources representing a range of purchase transaction types. They can be standard products, such as heavy load hour (HLH), light load hour (LLH), and super peak, but may be non-standard products provided the arrangements are considered firm. FOTs typically rely on standard enabling agreements as a contracting vehicle. FOT prices are determined at the time of the transaction, usually via an exchange or third-party broker, and are based on the then-current forward market price for power. An optimal mix of these purchases would include a range of volumes and terms for these transactions.

As described in Volume I, Chapter 5 (Reliability and Resiliency), solicitations for FOTs can be made years, quarters or months in advance, however, are generally committed to balance PacifiCorp's system on a balance of month, day-ahead, hour-ahead, or intra-hour basis. The terms, points of delivery, and products vary by individual market point. For FOT purchase limits, please refer to Volume I, Chapter 5 (Reliability and Resiliency), Table 5.8 – Maximum Available Front Office Transactions by Market Hub.

Additional discussion of how FOTs are modeled during the resource portfolio development process of the IRP is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

CHAPTER 8 – MODELING AND PORTFOLIO EVALUATION

CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios.
- PacifiCorp used Plexos software to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and number of new resources that could be pursued to serve customers over the next 20 years.
- The Plexos Long-Term (LT model) was used to generate initial portfolios and identify the resulting fixed costs. PacifiCorp used the Plexos Medium-Term schedule (MT model) to perform stochastic risk analysis of the portfolios. Each initial portfolio was evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three carbon dioxide (CO_2) price scenarios (zero, medium, high). An additional CO_2 policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gases (SC-GHG). Taken together, there are five distinct price-policy scenarios (medium gas/medium CO_2, medium gas/zero CO_2, high gas/high CO_2, low gas/zero CO_2, and the social cost of greenhouse gases).
- A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.
- Each initial portfolio was also evaluated in the Short-Term model (ST model) to establish system costs over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement (PVRR) which serves as the basis for selecting least-cost least-risk portfolios.
- The MT model risk-adjustment was added to the system cost determined by the ST model to calculate a final "risk-adjusted" PVRR measure of system cost. All three models in the Plexos suite, the LT, MT and ST, were thus used to arrive at final reliable portfolio for comparative analysis.
- A selection of competitive "variant" portfolios was analyzed using the other four price-policy scenarios in the ST and MT models to evaluate how each portfolio performs under differing market/policy conditions.
- Taking into consideration stakeholder comments and regulatory requirements, PacifiCorp produced additional studies that examine the potential impact of portfolio options on the system.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from the ST and MT models, comparing resource portfolios based on expected costs, low-probability high-cost outcomes, reliability, CO_2 emissions and other criteria.

Introduction

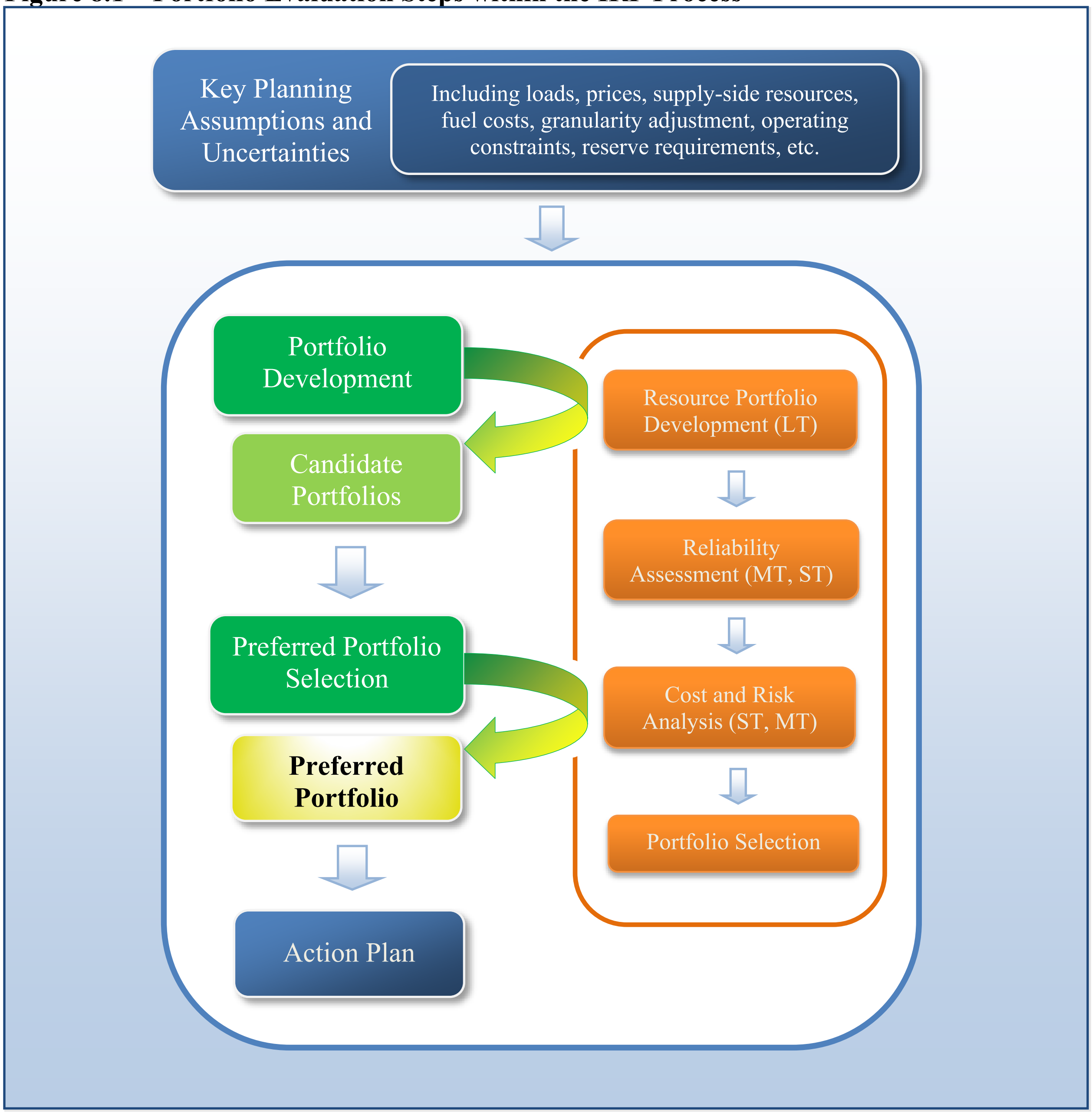
IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting reliability requirements. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter describes the cases examined at each modeling and evaluation step. The results of PacifiCorp's modeling and portfolio analysis are summarized in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).

Modeling and Evaluation Steps

Figure 8.1 summarizes the modeling and evaluation steps for the 2021 IRP, highlighted in green. The highest-level steps are (1) portfolio development, and (2) portfolio screening. The result of the final screening step is selection of the preferred portfolio.

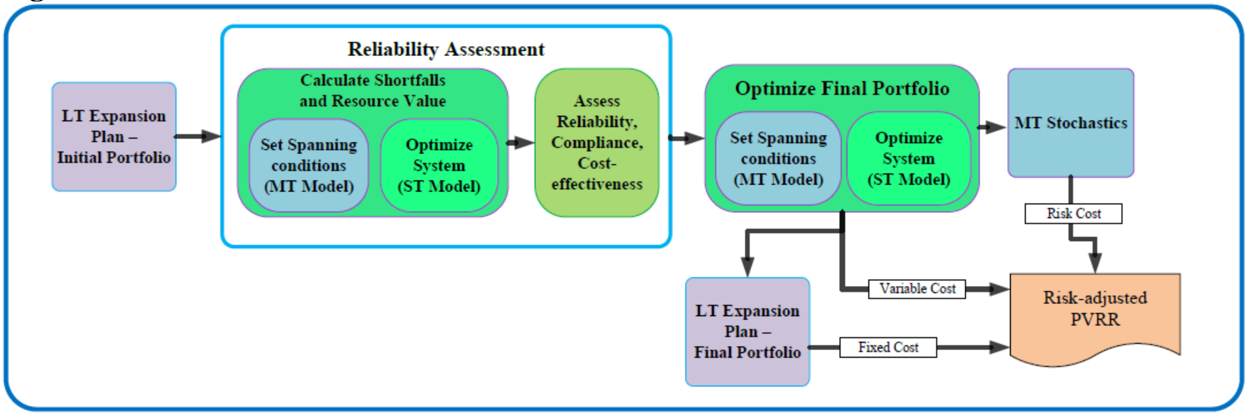
Figure 8.1 – Portfolio Evaluation Steps within the IRP Process



For each modeling and evaluation step, PacifiCorp developed unique resource portfolios, analyzed deterministic cost and stochastic risk metrics for each portfolio, and selected, based on comparative cost and risk metrics, the specific portfolios considered in the next modeling and evaluation step. The outcomes of each can inform the need for additional studies to test or refine assumptions in a subsequent screening analysis.

Figure 8.2 provides additional process detail regarding these portfolio processing elements, followed by descriptions of each element.

Figure 8.2 – Portfolio Production Process



Resource Portfolio Development

All IRP models are configured and loaded with the best available information at the time a model run is produced. This information is fed into the LT model, which is used to produce resource portfolios with sufficient capacity to be reliable on a 20-year aggregated granularity basis.

Reliability Assessment

Resource portfolios developed by the LT model are simulated in the ST model to quantify reliability shortfalls at an hourly level. The ST model also supports the assessment of each resource's net system value, inclusive of resources that are not part of the specific portfolio being examined. This allows for the refinement of each portfolio according to a highly granular view of its needs and at the same time provides the data necessary to incorporate portfolio modifications needed to optimally ensure reliability, regulatory compliance and cost-effectiveness. The adjusted portfolio is then rerun through the ST model to create an optimal dispatch which considers all resource availability and system requirements at an hourly level, inclusive of individual resource operations and market purchases.

Cost and Risk Analysis

Resource portfolios developed by the LT model and adjusted for reliability, compliance and cost-effectiveness by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed using Monte Carlo sampling of stochastic variables across the 20-year study horizon, which include load, natural gas and wholesale electricity prices, hydro generation, and unplanned thermal outages. The MT results are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR to guide portfolio selection.

Portfolio Selection

The portfolio selection process is based on modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the PVRR of system costs, assessed across a range of price-policy scenarios on a deterministic basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the deterministic PVRR with upper-tail stochastic risk PVRR. The final selection process considers cost-risk rankings, robustness of performance across pricing scenarios and other supplemental modeling results, including reliability and CO_2 emissions data as an indicator of risks associated with greenhouse gas emissions.

Resource Portfolio Development

Resource expansion plan modeling, performed with the LT model, is used to produce resource portfolios with sufficient capacity to achieve reliability over the 20-year study horizon by evaluating groups of hours on an aggregated basis. Each resource portfolio is refined for reliability at an hourly granularity during the reliability assessment development step. Each portfolio is uniquely characterized by the type, timing, location, and number of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks. New to this IRP is using the LT model to consider the retirement of both coal and gas resources endogenously in any year.

Long-Term (LT) Capacity Expansion Model

In the 2023 IRP, the LT model is used to establish an initial portfolio under expected conditions (medium gas, medium CO_2), and then modified for each case, based on study parameters, to eliminate shortfalls and maintain reliability. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints.[1] Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves plus a minimum planning reserve margin (PRM)[2] for each load area represented in the model.

The initial resource portfolio developed with the LT model is appropriately reliable to its granularity and performance limitations. Operating reserve requirements include contingency reserves, which are calculated as 3% of load and 3% of generation. The planning reserve margin in the 2023 IRP is set at a "floor" of 13% at each load area in the topology, as provided in Figure 8.3.

If an early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirement in each period and location. The LT model may also select additional resources that are more economic than an existing generating resource. In the 2023 IRP, the model is simultaneously considering resource additions for reliable and economic system operation both

[1] LT model performance limits the granularity at which the model can be run. For the 2023 IRP there is an additional reliability assessment performed in the ST model to ensure that final portfolios meet reliability requirements.

[2] The Plexos model uses 'capacity reserve margin' for what PacifiCorp has traditionally described as 'planning reserve margin' ("PRM"). While capacity reserve margin is slightly more precise, PRM is used in the 2023 IRP to reduce confusion over the use of multiple similar terms and because PRM is the industry standard term.

before and after existing generation resources retire, as well as which years to retire those existing resources in.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. To enhance the ability of the LT model to differentiate key resource types and system conditions, for the 2023 IRP, each month was split into seven blocks of hours based on load, wind, and solar, derived from PacifiCorp's 2021 IRP Update :

1. The single highest net load hour for the system (load net of wind and solar)
2. The single highest net load hour for the east balancing area
3. The single highest net load hour for the west balancing area
4. The top ten percent highest net load hours, excluding the above. 10% is approximately 70 hours per month, or an average of 2-3 per day, though some days may not have any hours in this group at all.
5. The top ten percent highest wind generation hours on a system basis.
6. The top ten percent highest solar generation hours on a system basis.
7. All other hours

The result of this modeling is to indicate to the LT model that wind and solar have very high availability in some hours, and very low availability in others. This would be expected to contribute to more moderate selections of wind and solar, as they will saturate some periods and have lower value. It would also be expected to contribute to selections of storage and peaking resources, targeted to cover periods in which wind and solar provide little generation supply.

Plexos LT model dispatch among blocks of hours in a month is not chronological, so it cannot constrain energy storage charging and discharging, except to ensure that over the course of a month these remain balanced. But within that limitation, Plexos determines generation and storage dispatch, optimal electricity flows between zones, and optimal market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Key modeling elements and inputs for the LT capacity expansion model include the following:

Transmission System

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths. Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.

Figure 8.3 – Transmission System Model Topology with Options

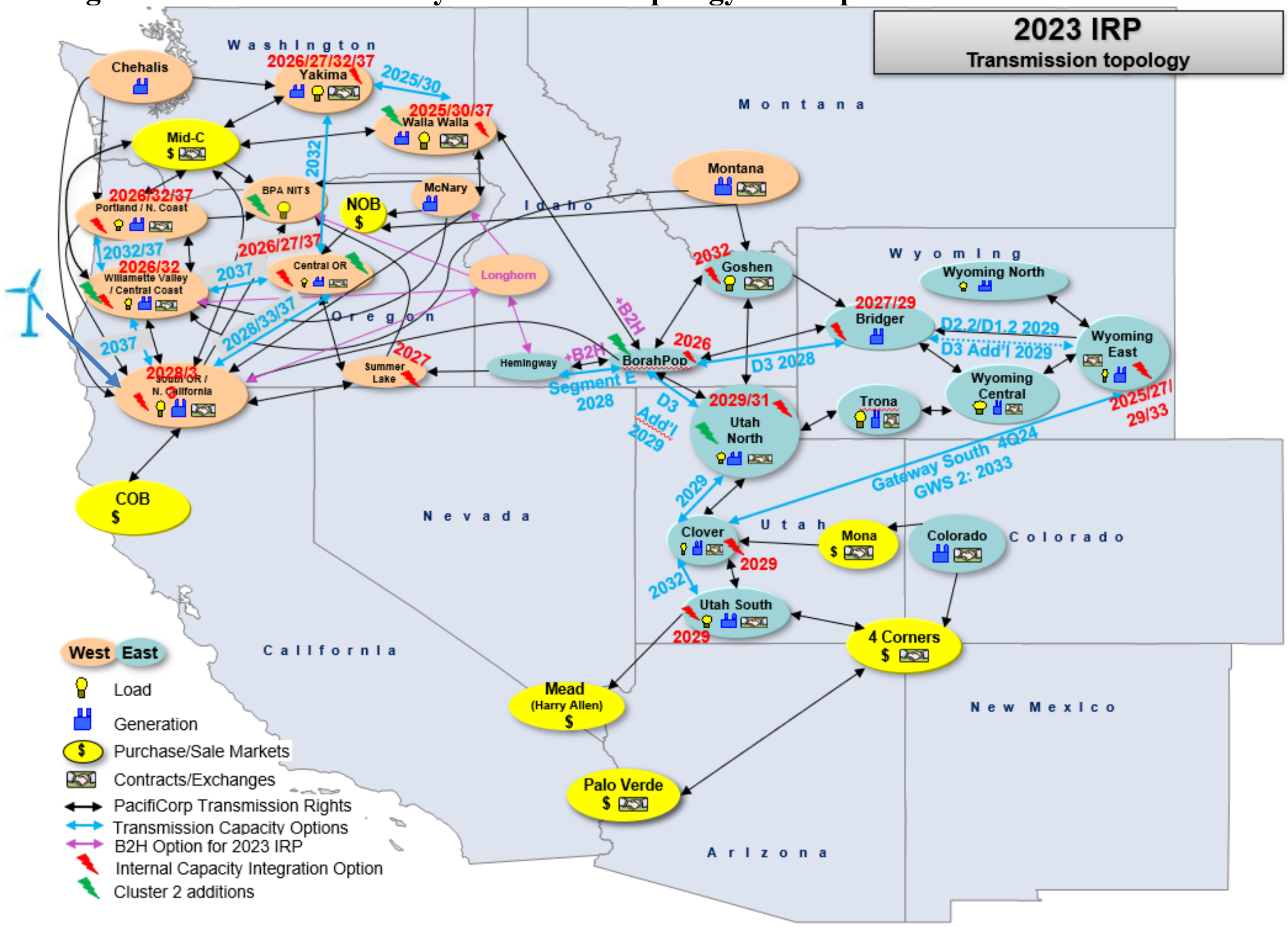


Figure 8.3 illustrates the 2023 IRP modeled topology where each transmission area or "bubble" is defined by any load and generation capability, it's location on the system and its connections to other bubbles.

Transmission Options

In addition to topology, Figure 8.3 illustrates modeled options for endogenous selection by the LT model. Over a span of three public input meeting, PacifiCorp presented information about transmission modeling as it was developed and presented interconnection and Cluster study results used to establish resource and transmission options based on the best available data.

"Interconnection" requires modifications, additions, or upgrades to physically and electrically connect a generating facility to the transmission system. Which requirements apply can be impacted by the generation facility type, detailed project specifications, location, prior/existing generation facilities and load.

Studies needed to identify interconnection requirements are interdependent and extensive. Interconnection is carefully regulated for the safety, reliability, and efficiency of the electrical grid. Requests for interconnection made by any project are regulated and managed in various ways, such as:

- **Serial queue:** Signed agreements and near-final serial queue requests.

- **Transition Cluster:** Remaining serial queue requests and 2020 requests.
- **Cluster Study 1:** Spring 2021 requests.
- **Cluster Study 2:** Spring 2022 requests.
- **Colstrip:** Interconnection to jointly-owned Colstrip transmission assets.
- **Surplus:** Interconnection of additional resources at the same point as an existing generator, with aggregate output not exceeding the existing limit.
- **Provisional:** Interconnection study identifies maximum permissible output before transmission upgrades that are not yet in service.
- **Oregon Community Solar:** projects under 3MW seeking to participate in the Oregon Community Solar program.
- ***Informational Studies*:** Informational only, proposal and results are not considered part of later interconnection requests and cannot lead to an interconnection agreement.

The process of evaluating the viability of future projects is complex and time-consuming, resulting in many pending interconnection requests. In 2020, PacifiCorp transitioned from a serial queue study process (one generator at a time) to an annual cluster study process (one study for all new requests in a given area). In the 2023 IRP PacifiCorp significantly enhanced its study of resource and transmission potential to better align with project expectations and costs resulting from these advanced studies. Cluster studies are described further in Chapter 4 – Transmission.

<u>Surplus Interconnections</u>

Surplus interconnections add more generation to an existing interconnection without requiring additional transmission lines. However, while installed nameplate capacity is increased at a site, the total megawatt output at any given time and location cannot exceed the original interconnection capacity. Considering the proliferation of variable resources which do not always occupy the entirety of a given transmission line, the 2023 IRP added surplus resource capability to its capacity expansion modeling options.

Added generation can be of the same type and can take the form of additional generating unit or increased generation capability, such as wind repowering resulting in higher nameplate capacity than the existing interconnection. In the event an added resource is of a different type, a hybrid is created. For example, a hybrid resource combination of solar, wind and storage allow a higher net capacity factor among all three resources, increasing overall generation, while avoiding the need for added transmission.

PacifiCorp has submitted surplus interconnection requests to evaluate the addition of solar to several wind resource sites in Wyoming.

Transmission Costs

In developing resource portfolios for the 2023 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.

Resource Adequacy

In its 2023 IRP, PacifiCorp used a 13% hourly planning reserve margin requirement for each topology location containing load in the LT model. The planning reserve margin applies in all periods and must be met by available resources within that area or imports from adjacent areas with excess resources available, subject to transmission constraints. This treatment is an improvement on a traditional planning reserve margin which accounts only for peak load capacity met by an estimated firm capacity contribution. Additionally, the 2023 IRP directly modeled operating reserve requirements in expansion plan model runs, which ensures that expansion resources selected to PRM requirements will also meet operating contingency spin and non-spin reserve requirements. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

Granularity and Reliability Adjustments

As detailed during the 2023 IRP public-input process, the granularity adjustment reflects the difference in economic value between an hourly 8760 cost calculation in ST modeling, and the seven-block per month representation used in the LT model.

This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the block granularity smooths out many of the storage arbitrage opportunities and also doesn't fully capture the effect of storage duration limits.

In parallel with the granularity adjustment, the reliability adjustment addresses unmet capacity needs by hour in the LT model portfolio selection. Much of the peak load hour requirements in mid-afternoon in the summer are adequately met by solar resources. However, resource requirements are driven by portfolio-dependent *net* load peaks (load less renewable resource output), which are harder for the LT model to identify.

While the granularity and reliability adjustments help direct the LT model to more cost-effective resources and a more reliable portfolio, the LT model cannot guarantee reliability at an hourly operational level. Marginal benefits decline as any resource type becomes a larger share of a portfolio, as it saturates the need in the hours it is available. A similar effect occurs with storage, where each incremental MW of system storage capacity must cover a longer duration.

Because of the performance limitations of capacity expansion optimization, the ST model is leveraged to refine the portfolio to achieve a final balanced and reliable mix of resources, as described under the Cost and Risk Analysis section of this analysis, further below.

Thermal Resource Options

Modeling in the 2023 IRP greatly expanded the range of endogenous selections available for optimization. In the 2019 IRP, 78 specific portfolio strategies were examined for the potential retirement of coal generating facilities. Upon moving to the Plexos model for the 2021 IRP this range of modeled possibilities expanded to more than 260,000 possible coal retirement configurations. In the 2021 RP cycle, for owned/operated coal units, potential retirement dates were based upon avoiding major overhauls, assuming a unit would be able to operate five years after an overhaul. In the 2023 IRP the possible combinations of outcomes available for endogenous selection in the LT model number in the trillions. This includes possibilities for conversion of coal units to burn natural gas, installation of carbon capture technology, selective catalytic reduction, selective non-catalytic reduction, and the capability to optimize natural gas generator retirements, new functionality in this IRP.[3]

In addition, for the 2023 IRP, all majority-owned and operated coal plant sites are considered candidates for surplus interconnection, such that other technologies can be added prior to the coal plant's retirement, with the aggregate of the existing and surplus resource output limited to the current maximum output of the coal resource. As a result, the LT model simultaneously evaluates the value of surplus resources both before and after the associated coal units retire, while at the same time evaluating when they should retire.

Table 8.1 reports the coal unit options modeled in the 2023 IRP, whereas Table 8.2 summarizes the options available for natural gas-fired units.

[3] Minority-owned coal units Colstrip 3 & 4 are subject to discussion with joint-owners; Craig and Hayden have agreed-upon retirement dates. Environmental compliance requirements were incorporated, including but not limited to Regional Haze, the Ozone Transport Rule, and carbon capture technology

Table 8.1 - Coal Generator Resource Options

Jim Bridger Units 1 and 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas/Alt. Fuel-2024		Gas														Retired				
Jim Bridger Units 3 and 4	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2037																Retired				
Gas/Alt. Fuel-2026				Gas												Retired				
Coal-CCUS 2028						CCUS												Retired		
Naughton Units 1 and 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2025				Retired																
Gas-2026				Gas											Retired					
Dave Johnston 1 and 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2032							Retired													
Dave Johnston 3	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2027						Retired														
Dave Johnston 4	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2039																		Retired		
Gas-2027					Gas													Retired		
Coal CCUS+SCR 2028						CCUS+SCR												Retired		
Wyodak	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2039																		Retired		
Gas-2027					Gas													Retired		
Coal SCR-2026				SCR														Retired		
Coal SNCR-2026				SNCR														Retired		
Dual Fuel-2027					Duel Fuel													Retired		
Hunter 1	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2042																				
Coal SCR-2026				SCR																
Coal SNCR-2026				SNCR																
Hunter 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2042																				
Coal SCR-2026				SCR																
Coal SNCR-2026				SNCR																
Hunter 3	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2042																				
Coal SCR-2026				SCR																
Coal SNCR-2026				SNCR																
Huntington 1	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2036															Retired					
Coal SCR-2026				SCR											Retired					
Coal SNCR-2026				SNCR											Retired					
Huntington 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2036															Retired					
Coal SCR-2026				SCR											Retired					
Coal SNCR-2026				SNCR											Retired					

Key
- Default/current operation
- Retirement option
- Gas conversion option
- Emissions technology option; SCR, SNCR, CCUS
- Assumed retired

Table 8.2 - Natural Gas Generator Resource Options

Chehalis	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2042																				
Currant Creek	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2042																				
Hermiston 1/2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2036															Retired					
Lakeside 1	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2042																				
Turbine Upgrade			Upgraded																	
Wet Compression																				
Lakeside 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2042																				
Turbine Upgrade			Upgraded																	
Wet Compression																				
Naughton Unit 3	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2036															Retired					
Gadsby 1	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									
Gadsby 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									
Gadsby 3	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									
Gadsby 4	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									
Gadsby 5	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									
Gadsby 6	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									

Key: Default/current operation; Retirement option; Assumed retired; Turbine upgrade; Wet compression

New Resource Options

Demand-Side Management

Energy efficiency resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand response resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

Wind and Solar Resources

Proxy wind and solar resources available for inclusion in the preferred portfolio are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources represent expected monthly generation levels such that half of the time actual monthly generation would fall below expected levels, and half of the time actual monthly generation would be above expected levels assuming no curtailments. Where

The ability for wind and solar resources, to reliably meet demand over time is impacted by the forecasted profiles, along with mix of other resources in the portfolio. The use of resource availability to meet requirements in all periods allows the model to endogenously account for declining capacity contribution due to the increasing penetration of resources with similar dispatch patterns.

Non-Emitting Resources

Two non-CO_2-emitting thermal resources are considered: advanced nuclear projects and non-emitting peaking units. Advanced nuclear resources are characterized by continuous operation and substantial storage in the form of heat stored as molten salt. In contrast, non-emitting peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls. The non-emitting peaking resource is assumed to use a non-CO_2 emitting fuel such as hydrogen.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

- Energy take – generation or extraction of energy from a storage reservoir for a specified period;
- Energy return – energy used to fill (or charge) a storage reservoir; and
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and variable costs, if applicable.

Market Purchases

Market purchases are transactions by the company's front office and represent short-term firm agreements for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., future months or quarters, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or the exchange provides a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all of the short-term firm physical power products, differing by delivery pattern and delivery period, which are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the contribution of short-term firm market purchases is accounted for in the portfolio-development process. For capacity expansion optimization modeling, market purchases contribute capacity toward meeting the 2023 IRP's planning reserve margin and supply energy to meet system needs.

Capital Costs

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. All capital costs evaluated in the IRP are converted to nominal levelized revenue requirement costs. Use of nominal levelized revenue requirement costs is an established methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the nominal levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes and income taxes over the life of the investment. The result is an annuity or annual payment that remains constant such that the PVRR is identical to the PVRR of the nominal requirement when using the same nominal discount rate.

General Assumptions

<u>Study Period and Date Conventions</u>

PacifiCorp executes its 2023 IRP models for a 20-year period beginning January 1, 2023 and ending December 31, 2042. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, except for coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period after ceasing coal-fired operation at the end of the prior year.

<u>Inflation Rates</u>

The 2023 IRP simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.27 percent is assumed. This escalation rate reflects the average of annual inflation rate projections for the period 2023 through 2042, using PacifiCorp's September 2022 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the Consumer Price Index.

<u>Discount Factor</u>

The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2023 IRP is 6.77 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[4] PVRR figures reported in the 2023 IRP are reported in 2022 dollars.

[4] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

CO_2 Price Scenarios

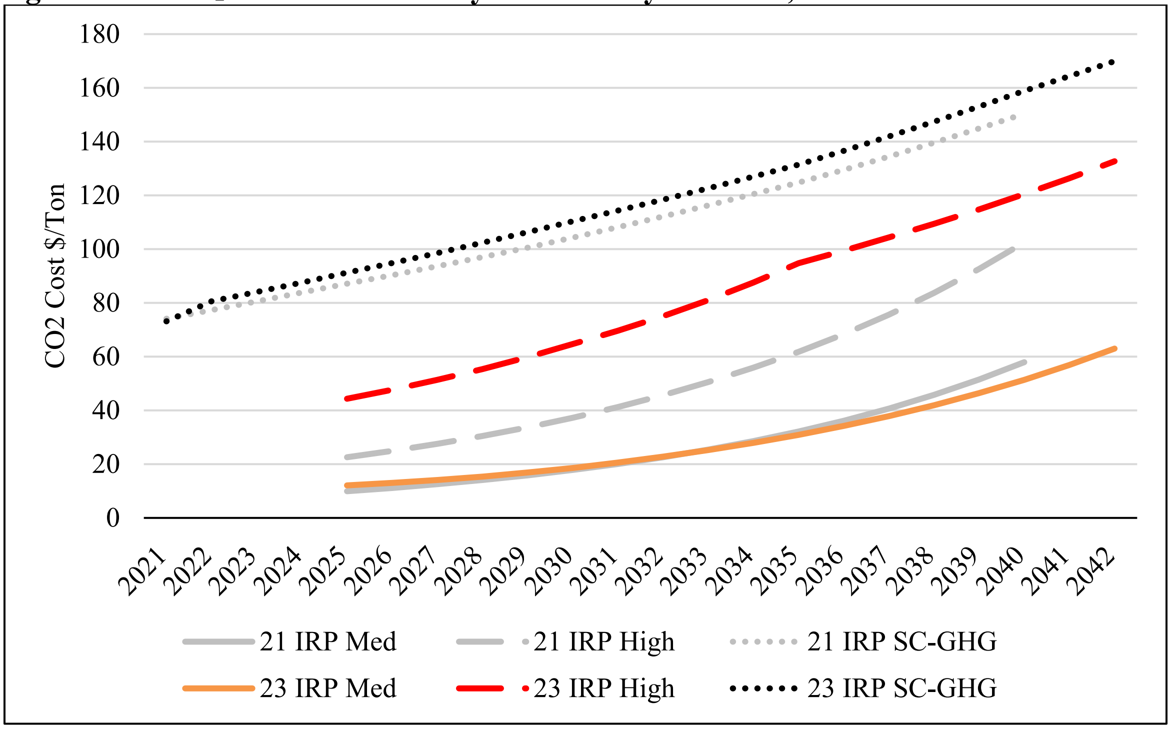
PacifiCorp used four different CO_2 price scenarios in the 2023 IRP—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The medium and high scenario are derived from a variety of sources, including government and electric utility forecasts, and expert third-party multi-client "off-the-shelf" subscription services. PacifiCorp grouped these forecasts around the median low and median high forecast. The highest grouping, consisting of six different forecasts, was averaged to form the high price case. The lowest grouping, also consisting of six different forecasts, was averaged to form the medium case. These scenarios apply a CO_2 price as a tax beginning 2025.

PacifiCorp also incorporated the social cost of greenhouse gas in compliance with Washington RCW 19.280.030. The 2023 IRP includes an adjusted cost of greenhouse gas emission reflecting inflation, defined by the Washington Utilities and Transportation Commission.[5] The social cost of greenhouse gas emissions is assumed to apply in all years of the study horizon. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

In all scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021. This is in addition to the assumed federal CO_2 policy represented in the zero, medium, high, and social cost of greenhouse gas scenarios described above. The modeled allowance cost reflects analysis conducted by Vivid Economics for the Washington Department of Ecology and starts at $58/ton in 2023.[6]

[5] Washington Utilities and Transportation Commission, Order 03, Docket No. U-190730, July 28, 2022.
[6] Summary of market modeling and analysis of the proposed Cap and Invest Program. June 2022. Available online at: https://ecology.wa.gov/DOE/files/4a/4ab74e30-d365-40f5-9e8f-528caa8610dc.pdf (Accessed 3/21/2023)

Figure 8.4 – CO_2 Prices Modeled by Price-Policy Scenario, 2021 and 2023 IRP



Wholesale Electricity and Natural Gas Forward Prices

For 2023 IRP modeling purposes, five electricity price forecasts were used: the official forward price curve (OFPC) and four scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

At the time PacifiCorp's 2023 IRP modeling inputs were prepared, the September 2022 OFPC was the most current OFPC available. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflects market forwards at the close of a given trading day.[7] As such, these 36 months are market forwards as of September 2022. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party multi-client "off-the-shelf" price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAxmp[8] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

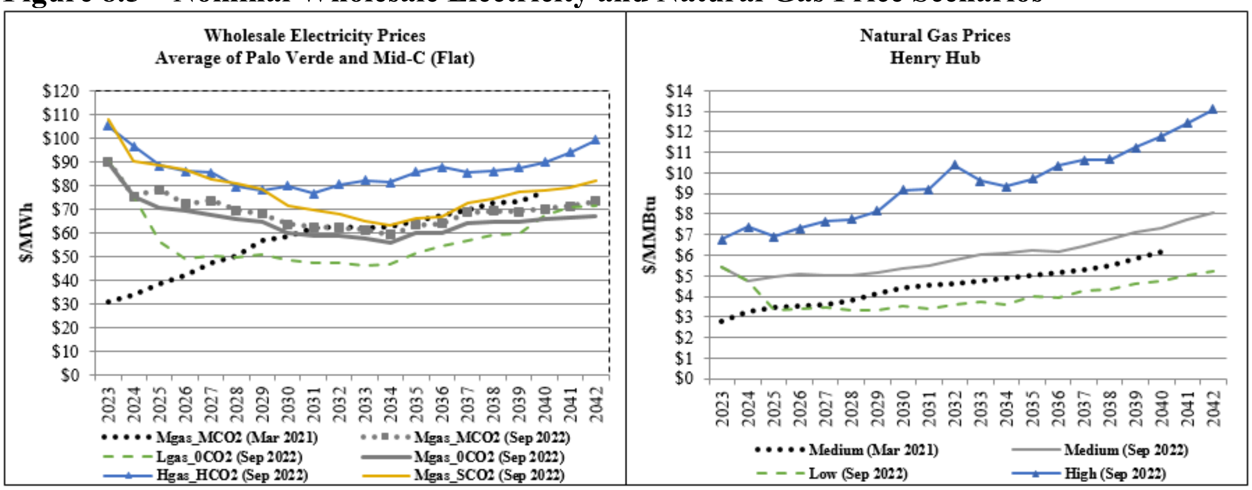
[7] The March 2021 OFPC prompt month is May 2021; April 2021 would be traded as "balance of month" when the OFPC is released.
[8] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2026 before transitioning to a pure-fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party multi-client "off-the-shelf" subscription services.

PacifiCorp's OFPC for electricity and each of its five scenarios were developed from one of three (medium, low, high) underlying expert third-party natural gas price forecasts in conjunction with one of four CO_2 price scenarios.[9] The OFPC used in the 2023 IRP does not assume any CO_2 policy or tax in conjunction with its medium gas price forecast. However, PacifiCorp's 2021 IRP "medium case" price forecast is not the OFPC but a scenario that couples medium gas with a medium CO_2 price, applied for forecasting purposes as a tax. Thus, the 2023 IRP medium case differs from that of the September 2022 OFPC by assuming a medium CO_2 price starting in 2025. This medium CO_2 price serves as a proxy for a potential future CO_2 policy.

Figure 8.5 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2023 IRP.

Figure 8.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Cost and Risk Analysis

Short-Term (ST) Schedule Model

The ST model uses the same common input assumptions described for the LT model with additional data provided by two other Plexos models. The LT model results provide the initial capacity expansion plan, and the MT model provides an optimized set of spanning conditions.

[9]Zero CO_2, medium CO_2 price, high CO_2 price, and a society-based cost of CO_2.

Spanning conditions are constraints that must be observed across periods of time that extend beyond the ST model's ability to "see" as it chronologically optimizes several days of hourly data at a time (e.g., an annual emissions limit). The MT model can determine for each month how each spanning condition is allocated for the ST model's use. The result is that even though the ST model is focused on hourly details and cannot simultaneously account for limitations that span across every hour in a year, the model will nonetheless appropriately adhere to an annual constraint.

Reliability Assessment and System Cost

The ST model begins with a portfolio from the LT model that has not yet been refined to reflect the reliability and compliance needs of a particular study (e.g., a particular sensitivity or price-policy scenario). The ST model is first run at an hourly level for 20 years in order to retrieve two critical pieces of data: 1) shortfalls by hour, and 2) the value of every potential resource to the system that is specific to the portfolio itself, and other input assumptions, such as the price-policy scenario.

This information is used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR which is risk-adjust by outcomes of MT model stochastics.

Resource Value

Plexos calculates a locational marginal price (LMP) specific to each area in each hour that is based on supply and demand in that area and available imports and exports on transmission links to adjacent areas. This is also known as a shadow price. Plexos also calculates the marginal price specific to ancillary services (i.e., operating reserves) in each hour. Plexos then multiplies these prices by a resource's optimized energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. In an organized market, this would represent the expected payments based on market-clearing prices.

When variable costs (such as fuel, emissions, and VOM) are subtracted out, the result is a resource's "net revenue". Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, modeling capabilities, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated, and marginal prices will again reflect the variable cost of an available resource.

Portfolio Refinements

While many resource options are evaluated, new generation resources are mostly restricted to two circumstances: surplus or replacement resources at generators that are eligible to retire, and new resources at locations with interconnection or transmission upgrade options.

These interconnection and transmission upgrade options are limited and can be expensive. Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in "firm" capacity creates a need for additional interconnection capacity elsewhere, and a key strategy is maximizing the "firmness" of each MW of interconnection capacity to provide greater value. For this reason, in the 2023 IRP, the modeling of replacement and expansion resources was not limited by the nameplate of resources being added, but rather to by an hourly maximum generation constraint. As such, the model is able to select any combination of resources leading to a smoothing of hourly capacity among various renewable or peaking/firm resources. Batteries are assumed to always be co-located with other resources, enabling them to shift energy accumulated during periods of high solar radiance, wind speed or other generation, and increase the effective capacity contribution of the combination of resources in a given location.

Portfolio Cost

The second run of the ST model produces an optimized dispatch of the reliability-adjusted portfolio to reflect least-cost operations while meeting all requirements and adhering to modeled constraints. The ST model's hourly granularity means that this system cost will be highly accurate, taking into account operational nuances that are obscured in the less granular LT and MT models. This in turn means that when evaluating the constellation of all competitive portfolios, the comparison will be based on appropriate relationships among all system components to yield an accurate PVRR.

Additional Measures

- Annual and energy not served (ENS)
- Annual CO_2 emissions.

Medium-Term (MT) Schedule Model

The MT model uses the same common input assumptions described for LT and ST models with additional data provided by the LT and ST model results (e.g., the capacity expansion portfolio). While the LT and ST models supply an optimized portfolio for each case, the MT model can bring the advantages of stochastic-driven risk metrics to the evaluation of the studies. While deterministic ST system cost results are the most precise available due the hourly granularity, the MT model provides the necessary data to calculate a stochastic risk metric for each case, which is then added to the ST system cost outcomes to produce the risk adjusted PVRR for each case.

Cost and Risk Analysis

Once unique resource portfolios are developed using the LT and ST models, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed with the MT model.

The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.

The stochastic parameters used in the MT model for the 2023 IRP are developed with a short-run mean reverting process, whereby mean reversion represents a rate at which a disturbed variable returns to its expected value. Stochastic variables may have log-normal or normal distribution as appropriate. The log-normal distribution is often used to describe prices because such distribution is bounded on the low end by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average. Unlike prices, load generally does not have such skewed distribution and is generally better described by a normal distribution. Volatility and mean reversion parameters are used for modeling the volatilities of the variables, while accounting for seasonal effects. Correlation measures how much the random variables tend to move together.

Stochastic Model Parameter Estimation

Stochastic parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. Loads and commodity prices are mean-reverting in the short term. For instance, natural gas prices are expected to hover around a moving average within a given month and loads are expected to hover near seasonal norms. These built-in responses are the essence of mean reversion. The mean reversion rate tells how fast a forecast will revert to its expected mean following a shock. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. The stochastic parameters are used to drive the stochastic processes of the following variables:

- Representative natural gas prices for PacifiCorp's east and west balancing authority areas;
- Electricity market prices for Mid-C, COB, Four Corners, and Palo Verde;
- Loads for California, Idaho, Oregon, Utah, Washington, and Wyoming regions; and
- Hydro generation.

Volume II, Appendix H (Stochastic Parameters) discusses the methodology for developing the stochastic parameters for the 2023 IRP.

For unplanned thermal outages, PacifiCorp assumes a uniform distribution around an expected rate. For existing units, the expected unplanned outage rates by unit are based on its historical performance. For new resources, the unplanned outage rates are as specified for those resources as listed in the supply-side resource table in Volume I, Chapter 7 (Resource Options). Table 8.3 through Table 8.10 summarize updated stochastic parameters and seasonal price correlations for the 2023 IRP.

Table 8.3 – Short-Term Load Stochastic Parameters

Short-Term Volatility	CA/OR without Portland	Portland	ID	UT	WA	WY
Winter 2023 IRP	0.044	0.041	0.038	0.024	0.050	0.021
Spring 2023 IRP	0.036	0.035	0.064	0.035	0.042	0.021
Summer 2023 IRP	0.045	0.060	0.061	0.054	0.054	0.021
Fall 2023 IRP	0.042	0.036	0.047	0.035	0.044	0.020
Short-Term Mean Reversion	**CA/OR without Portland**	**Portland**	**ID**	**UT**	**WA**	**WY**
Winter 2023 IRP	0.261	0.252	0.263	0.380	0.171	0.279
Spring 2023 IRP	0.236	0.229	0.146	0.332	0.164	0.109
Summer 2023 IRP	0.169	0.183	0.143	0.265	0.173	0.190
Fall 2023 IRP	0.251	0.365	0.128	0.234	0.213	0.224

Table 8.4 – Short-Term Gas Price Parameters

Short-Term Volatility	East Gas	West Gas
Winter 2023 IRP	0.272	0.237
Spring 2023 IRP	0.134	0.224
Summer 2023 IRP	0.135	0.148
Fall 2023 IRP	0.153	0.743
Short-Term Mean Reversion	**East Gas**	**West Gas**
Winter 2023 IRP	0.129	0.074
Spring 2023 IRP	0.304	0.155
Summer 2023 IRP	0.525	0.405
Fall 2023 IRP	0.244	0.570

Table 8.5 – Short-Term Electricity Price Parameters

Short-Term Volatility	Four Corners	COB	Mid-Columbia	Palo Verde
Winter 2023 IRP	0.194	0.191	0.223	0.174
Spring 2023 IRP	0.193	0.238	0.564	0.164
Summer 2023 IRP	0.311	0.946	0.392	0.288
Fall 2023 IRP	0.215	0.189	0.190	0.206
Short-Term Mean Reversion	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**
Winter 2023 IRP	0.103	0.101	0.101	0.102
Spring 2023 IRP	0.216	0.213	0.477	0.199
Summer 2023 IRP	0.213	1.014	0.300	0.149
Fall 2023 IRP	0.238	0.297	0.294	0.230

Table 8.6 – Winter Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.399	1.000				
COB	0.295	0.577	1.000			
Mid - Columbia	0.337	0.522	0.725	1.000		
Palo Verde	0.451	0.886	0.575	0.558	1.000	
Natural Gas West	0.688	0.203	0.262	0.292	0.244	1.000

Table 8.7 – Spring Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.157	1.000				
COB	0.134	0.384	1.000			
Mid - Columbia	0.139	0.406	0.584	1.000		
Palo Verde	0.133	0.718	0.282	0.275	1.000	
Natural Gas West	0.618	0.150	0.189	0.143	0.084	1.000

Table 8.8 – Summer Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.130	1.000				
COB	0.110	0.219	1.000			
Mid - Columbia	0.234	0.400	0.608	1.000		
Palo Verde	0.127	0.785	0.295	0.472	1.000	
Natural Gas West	0.810	0.110	0.065	0.207	0.068	1.000

Table 8.9 – Fall Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.047	1.000				
COB	0.131	0.296	1.000			
Mid - Columbia	0.122	0.257	0.708	1.000		
Palo Verde	0.034	0.768	0.372	0.335	1.000	
Natural Gas West	0.199	-0.008	-0.087	-0.033	0.030	1.000

Table 8.10 – Hydro Short-Term Stochastic

	Short-Term Volatility	Short-Term Mean Reversion
Winter 2023 IRP	0.257	0.677
Spring 2023 IRP	0.201	0.766
Summer 2023 IRP	0.195	1.796
Fall 2023 IRP	0.276	0.359

Monte Carlo Simulation

During model execution, the MT model makes time-path-dependent Monte Carlo draws for each stochastic variable based on input parameters. The Monte Carlo draws are percentage deviations from the expected forward value of each variable. The Monte Carlo draws of the stochastic variables among all resource portfolios modeled are the same, which allows for a direct comparison of stochastic results among all resource portfolios being analyzed. In the case of natural gas prices, electricity prices, and regional loads, the MT model applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

Stochastic Portfolio Performance Measures

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from the MT model include:

- Stochastic mean PVRR
- Upper-tail Mean PVRR
- 5^{th}, 90^{th} and 95^{th} percentile PVRR

- Standard deviation
- Risk-adjustment (5% of the 95th percentile)

Stochastic Mean PVRR

The stochastic mean PVRR is the average of system net variable operating costs among 20 iterations, combined with the nominal levelized capital costs and fixed costs corresponding to the LT model for any given resource portfolio. The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, long term contracts, system balancing market purchase expenses and sales revenues, reserve deficiency costs, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources are calculated on a nominal-levelized basis. Other components in the stochastic mean PVRR include CO_2 emission costs for any scenarios that include a CO_2 price assumption. The stochastic mean PVRR, limited by performance constraints of the MT model, is not used directly in portfolio selection; instead, the more granular ST PVRR serves as the base measure of net system cost, modified appropriately by stochastic risk.

Upper-Tail Mean PVRR

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the three highest production costs on a net present value basis. The portfolio's fixed costs, taken from the LT model, are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

5th and 95th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 20 Monte Carlo iterations. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 20 Monte Carlo iterations. The production cost is expressed as a net present value of annual costs over the period 2021 through 2040. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Risk-Adjustment

The MT model outcomes of the 20 stochastic samples are used to calculate a risk-adjustment measuring the relative risk of low-probability, high-cost outcomes. This measure is calculated as five percent of system variable costs from the 95th percentile. This metric expresses a low-probability portfolio cost outcome as a risk premium based on 20 Monte Carlo simulations for each resource portfolio and applied to the hourly-granularity deterministic PVRR. The rationale behind the risk-adjusted PVRR is to have a consolidated cost indicator for portfolio ranking, combining the most precise available system cost and high-end cost-risk concepts.

Forward Price Curve Scenarios
Preferred portfolio variants developed during the portfolio-development process are analyzed in the MT model with up to five price-policy scenarios. Price assumptions for each of these scenarios are subject to short-term volatility and mean reversion stochastic parameters when used in the MT model. The approach for producing wholesale electricity and natural gas price scenarios used for MT model simulations is identical to the approach used to develop price scenarios for the portfolio-development process.

Other Plexos Modeling Methods and Assumptions

Transmission System

The base transmission topology shown in Figure 8.3 is used in each of the three Plexos models, LT, ST and MT. Any transmission upgrades selected by LT and ST model processes that provide incremental transfer capability among bubbles in this topology are part of the portfolio and thus included in the MT stochastics and final ST optimizations.

Resource Adequacy

The reality of modeling large complex power systems in a world of significant variable resources is that availability must be compared to requirements in all modeled periods, as measurements only at peak do not adequately establish system reliability. Consistent with past IRPs, the PRM is a portfolio selection driver adequate to the capabilities of the LT model, but is not used once the initial portfolio is established. ST reliability modifications to the portfolio rely on hourly resource availability and system requirements to directly determine reliability shortfalls and any additional resource need at the hourly level. MT stochastic model runs optimize unit commitment and dispatch logic on the resulting fixed portfolio to meet all requirements, including operating reserve and regulation reserves.

Energy Storage Resources

Storage resources such as battery energy storage systems (BESS), compressed air energy storage (CAES), and flow storage have many potential advantages, including storage for frequency regulation, grid stabilization, transmission loss reduction, reduced transmission congestion, renewable energy smoothing, spinning reserve, peak-shaving, load-levelling, transmission and distribution deferral, and asset utilization.

Each Plexos model (LT/MT/ST) dispatches storage resources endogenously, subject to any applicable constraints, for example requirements to charge from onsite solar or for the combined solar and storage output and reserves to remain within a single interconnection limit. The model can deploy energy storage for the most cost-effective uses, including any combination of load ramping and leveling, reserve carrying, and to complement the benefits of renewable resource additions, particularly co-located renewables.

Other Cost and Risk Considerations

In addition to reviewing the risk-adjustment, ENS, and CO_2 emissions data, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

Fuel Source Diversity
PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, storage resources, DSM resources and market purchases.

Customer Rate Impacts
To derive a rate impact measure, PacifiCorp computes the change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the risk adjusted PVRR results from the models and capital costs on a nominal levelized basis. While this approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for rate-making purposes.

Market Reliance
To assess market reliance risk, PacifiCorp quantifies market purchases for each portfolio allowing comparisons among cases in Chapter 9 – Modeling and Portfolio Selection Results. Starting in the 2021 IRP, market purchases were restricted compared to past IRPs, as described in Volume I, Chapter 7 (Resource Options).

Portfolio Selection

Portfolios are measured for relative performance regarding system costs, risk-adjusted system costs, ENS and CO_2 emissions. The risk adjusted PVRR accounts for relative upper tail stochastic risk among portfolios.

Each portfolio under examination at a given step in the analysis is compared based on cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include upper-tail PVRR, risk-adjusted PVRR, ENS and emissions. As noted above, market reliance risk was also evaluated. The comparisons of outcomes are detailed, ranked, and assessed in the next chapter.

Additional quantitative analysis can be performed to further assess the relative differences among top-performing portfolios; qualitative analysis can also be considered where appropriate during portfolio selection on the basis of known factors that could not be readily captured in models.

Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps. For the 2023 IRP natural gas resources are available in the endogenous LT model for selection, a change from the 2021 IRP.

During the final screening process, the results of any further resource portfolio developments will be ranked by risk-adjusted PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the five price-policy price curve scenarios. Resource portfolios with the lowest risk-adjusted PVRR receive the highest rank. Final screening also considers system cost PVRR data from the Plexos models and other comparative portfolio analysis. At this stage, PacifiCorp reviews additional metrics from the models looking to identify if ENS and CO_2 emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted PVRR basis.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2021 IRP, organized here into major development categories:

- Initial Portfolios
  - P-series
- Preferred Portfolio Selection
  - Top Performing Portfolio
  - Preferred Portfolio Variants
- Washington Portfolios and Sensitivities[10]

Additional portfolio detail can be found in Volume II, Appendix I (Capacity Expansion Results).

Initial Portfolios

Informed by the public-input process, the P-series cases endogenously explore a multitude of potentially significant interactions among retirement options including the potential to convert coal units to natural gas operations, retire units prior to end-of-life, install carbon-capture equipment on coal-fired facilities, or retire units at end-of-life. In addition to the core functionality of selecting the optimal timing, size, and location of proxy resources, in the 2023 IRP Plexos also optimizes natural gas retirements. As in the 2021 IRP, the modeling includes a wide range of transmission options for selection, assessed simultaneously with all other competing elements. The initial portfolios also consider how resource selections change with price-policy assumptions that deviate from the medium natural gas price and medium CO_2 price assumptions used to develop many resource portfolios. All the initial portfolios rely on the combined capabilities of three optimization models within Plexos, the LT model, MT model and ST model.

In response to stakeholder feedback, new natural gas proxy resources were made available for selection in the Initial Portfolios. There are however considerable stranded-cost risks associated with planning a system that is reliant on new natural gas resources with depreciable lives ranging between 30 to 40 years (i.e., a new gas-fired resource placed in service in 2030 would be depreciated as late as 2070). It is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such a facility in many parts of PacifiCorp's service territory.

[10] Informational portfolios that are not eligible for selection as the state-wide preferred portfolio. For the purposes of the state of Washington, these additional portfolios are not strictly required for this filing. However, they are provided as a point of reference leading up to the Annual Clean Energy Progress Report to be filed by July 1, 2023. *See* WAC 480-100-650(3).

Further, PacifiCorp observed that in the 2020AS RFP there were no bids for new natural gas resources. Therefore, new natural gas proxy resources were not made available for selection in any of Initial Portfolios. Therefore, when considering current state policies and the consistent trajectory of federal policy over the past 10-20 years, careful consideration must be given to natural gas selections among the competing portfolios.

Portfolios generated with SCGHG price-policy assumptions are consistent with RCW19.280.030 in Washington.

Table 8.11 provides the initial portfolio definitions for this IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Volume II, Appendix I (Capacity Expansion Results).

Table 8.11 – Initial Portfolio Case Definitions

Case Type[(a)]	Price-Policy	Existing Coal[(b)]	Existing Gas[(b)]	Other Existing Resources	Proxy Resources[(c)]
P	MM	Optimized	Optimized	End of Life	All allowed
P	MN	Optimized	Optimized	End of Life	All allowed
P	LN	Optimized	Optimized	End of Life	All allowed
P	HH	Optimized	Optimized	End of Life	All allowed
P	SC	Optimized	Optimized	End of Life	All allowed

(a) "P" refers generically to "portfolio". Studies are named in the format "P-MM", for example, meaning the initial portfolio run under medium natural gas, medium carbon price assumptions.
(b) Thermal coal and gas resources are endogenously optimized for retirements, conversions and technology installations.
(c) Optimized proxy portfolio selections include renewables, off-shore wind, storage, natural gas, transmission, DSM, purchases and sales, etc.

All initial portfolios consider variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or CCUS retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing.

P-series (optimized retirements, conversions, and technology installations)
P-series portfolios are fully optimized using the best available input data and assumptions regarding requirements and constraints. The P-MM case represents a reasonably likely future that assumes medium gas prices and a medium CO_2 price proxy for future carbon emissions policy. In this series, coal and natural gas retirement timing is optimized, whereas other existing resources are assumed to operate through end of life; contracts expire at the end of their term. Based on the logic of optimization modeling, P-series cases are expected to perform well compared to other case types within the same price-policy environment assumptions given that the models will have the most latitude to find a low-cost portfolio solution. The P-series of cases includes a unique portfolio developed under each of the five price-policy scenarios.

Preferred Portfolio Selection Cases

Certain additional cases were developed directly from the top-performing case (P-MM) based on analysis of portfolios from the twenty initial cases as described above to evaluate the impacts of specific future scenarios not considered elsewhere, but which may be adopted into the preferred portfolio if the analysis warrants their inclusion. In the 2023 IRP, there are eight preferred portfolio selection cases referred to as the "P Variants" as shown in Table 8.12:

Table 8.12 – Preferred Portfolio Variants

Portfolio	Description
P01-JB3-4 GC	Early conversion of Jim Bridger 3 & 4 to gas-fired
P02-JB3-4 EOL	Jim Bridger 3 & 4 remain coal-fired through end of life
P03-Hunter3-SCR	SCR installed on Hunter 3 instead of SNCR
P04-Huntington RET28	Early retirement of Huntington 1 in 2028
P05-No NUC	Nuclear selections replaced with non-emitting peakers
P06-No Forward Tech	Nuclear and non-emitting peakers replaced with non-gas options
P07-D3-D2 32	Delay D3 and D2.2 transmission until 2032
P08-No D3-D2	Exclude selection of D3 and D2.2 transmission
P09-No WY OTR	Assume Wyoming is not subject to OTR
P10-Offshore Wind	Includes offshore wind project
P11-Max NG	Nuclear and non-emitting peakers replaced with natural gas
P12-RET Coal 30 NG 40	Retire all coal by year-end 2029; retire all natural gas by year-end 2039
P13-All EE	Includes all energy efficiency programs
P14-All GW	Includes all Energy Gateway transmission options
P15-No GWS	Exclude Energy Gateway South
P16-No B2H	Exclude selection of B2H transmission
P17-Col3-4 RET25	Colstrip units 3 and 4 retire end of 2025
P18-Cluster East	Enable Cluster 1 Clover transmission in Area 5/6/7
P19-Cluster West	Enable Cluster 1 Area 12 transmission and resources
P20-JB3-4 CCUS	JB3-4 converts to CCUS in 2028

Each variant case begins with inputs and assumptions identical to the preferred portfolio (P-MM), which is the top performing portfolio.

P01-JB3-4 GC

This variant tests a 2026 gas conversion assumption for Jim Bridger Units 3 and 4, accelerating the conversion to natural gas fueling from 2030. The study is re-optimized with the accelerated assumption.

P02-JB3-4 EOL[11]

In this variant, Jim Bridger Units 3 and 4 are assumed to run as coal-fired units through end-of-life. This sensitivity evaluates the cost and risk merits of this strategy by excluding early retirements or conversions, re-optimizing the portfolio, and comparing outcomes.

P03-Hunter3-SCR

This variant replaces the Hunter 3 installation of SNCR with SCR to establish the net cost/benefit of the more expensive SCR technology.

[11] P02-JB3-4 EOL variant is defined as the *reference case* per Wyoming Order, Docket No. 90000-144-XI-19 (Record No. 15280). Additional information regarding the reference case is given in Chapter 9 (Modeling and Portfolio Selection Results).

P04-Huntington RET28
This variant tests the potential system cost or benefit of retiring Huntington unit 1 in 2028, four years earlier than in the preferred portfolio. Based on the early retirement date, the portfolio is re-optimized in the absence of this unit.

P05-No NUC
This case removes the Natrium™ demonstration project in 2030, and subsequent 2031 and 2033 nuclear plants using the same Natrium™ technology from the preferred portfolio. The portfolio is then re-optimized to determine a portfolio necessary to maintain reliability. The purpose of the sensitivity is to evaluate possible alternatives in the absence of nuclear resource options. Additionally, this sensitivity seeks to evaluate the potential risk that these projects are unable to achieve online and operating status for any reason.

P06-No Forward Tech
This variant removes both nuclear and non-emitting peaking resources to assess the potential for an alternate pathway to reliability. The study disallows new gas options (as compared to the "Max NG" variant described below).

P07-D3-D2 32
The delay of transmission projects D3 and D2.2 is evaluated in this sensitivity by assuming a 2032 online year rather than 2029 as in the preferred portfolio. The study is re-optimized with the decelerated assumption.

P08-No D3-D2
In variant P08-No D3-D2, the D3 and D2.2 transmission projects are not allowed to be selected as part of the optimal capacity expansion plan. The portfolio is re-optimized in the absence of these projects.

P09-No WY OTR
Currently, the status of Wyoming regarding the Ozone Transport Rule is not completely settled. The 2023 IRP conservatively assumes that Wyoming will be included among those states subject to OTR restrictions on NOx emissions beginning in 2024. This counterfactual analysis removes Wyoming from OTR constraints to identify the impacts on modeled outcomes.

P10-Offshore Wind
In the P-series cases, offshore wind was available for portfolio selection beginning in year 2028, though it is reliant upon transmission upgrades that may not be available until later. As offshore wind has not been endogenously selected, a minimum of 1000 MW was required to be selected. Additionally, the necessary on-shore transmission required to enable offshore wind was available for selection by offshore wind or by any other appropriately located proxy resources to ensure that co-located resources could be selected to complement the offshore wind and that it is competitive with other options. As offshore wind was not selected for the preferred portfolio, this counterfactual includes it, and is used to assess system impacts and the magnitude of the costs and benefits associated with offshore wind.

P11-Max NG
In this sensitivity, new gas peaking resources replace non-emitting peaking resources and new combined cycle combustion turbines replace advanced nuclear resources. As natural gas resources

were available for selection in the base model assumptions but were not selected, this sensitivity is the counterfactual, wherein natural gas resources are forced into the solution to assess the magnitude of the impact.

P12-RET Coal 30 NG 40
This variant features the retirement of all coal resources by 2030 using an optimized retirement strategy within the first seven years of the planning horizon. Similarly, natural gas resources also retire by 2040. Other existing resources continue as usual.

P13-All EE
Variant P13-All EE includes all energy efficiency, providing a bookend assessment of the cost and risk trade-off as well as portfolio impacts.

P14-All GW
The 2017, 2019 and 2021 IRPs have each identified Energy Gateway projects and collectively point toward the need for future transmission expansion to meet future load and provide cost-effectives alternatives to pollution-emitting resources. This sensitivity examines the relative costs and benefits of including all major components of Energy Gateway and accompanying resource selections.

P15-No GWS
The Energy Gateway South and associated Energy Gateway Segment D.1[12] projects directly enable 2,030 MW (nameplate) of interconnected resources; most of which are wind resources procured in PacifiCorp's 2020 All-Source RFP. Gateway South is also required for certain interconnection requests in Utah and enables future transmission upgrades. In the P15-No GWS case, both the transmission project and enabled resources and future transmission are removed. The portfolio is re-optimized in the absence of these projects.

P16-No B2H
In this sensitivity the transmission segments associated with the Boardman-to-Hemingway project are removed along with 600 MW (interconnection capability) of enabled resources. The portfolio is re-optimized in the absence of these projects.

P17-Col3-4 RET25
This study includes the retirement of Colstrip units 3 and 4 at the end of 2025, a variance from the preferred portfolio assumption which maintains PacifiCorp's participation share through 2029. The portfolio is re-optimized assuming the accelerated retirements.

P18-Cluster East
The first of two transmission cluster study variants, P18-Cluster East enables five Clover transmission components associated with Cluster 1, Areas 5, 6, and 7, which includes a prerequisite and a related transfer capability increase. The portfolio is re-optimized with this transmission expansion to evaluate portfolio impacts, costs and risks.

[12] Refer to Volume I, Chapter 4 (Transmission) for details regarding these projects.

P19-Cluster West
Similar to P18-Cluster East, the "Cluster West" variant enables Southern Oregon transmission upgrades supporting Cluster 1, Area 12 resources and a transfer capability increase. The portfolio is re-optimized with this transmission expansion to evaluate portfolio impacts, costs and risks.

CCUS Variant (P-20-JB3-4 CCUS)
This study analyzes the impacts of assuming carbon capture utilization and sequestration technology is installed on specific existing coal units in year 2028. Variant P-20-JB3-4 CCUS was run as a counterfactual to preferred portfolio selections.

Washington Portfolios

Washington's CETA legislation indicates four key studies:

- **W-10 CETA** – This study complies with CETA's Clean Energy Transformation Standards. This sensitivity also includes the requirement to use the social cost of greenhouse gases (SC) price-policy assumption in resource acquisition decisions. In Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA compliant outcomes.

- **W-11 Climate Change Counterfactual** - WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change." Please see Appendix A for additional detail regarding how climate change is incorporated into the base forecast. Because the base forecast includes climate change, the 20-year normal sensitivity for Washington is the counterfactual to this case – i.e., a study which does not incorporate specific climate change considerations.

- **W-12 Maximum Customer Benefit** - WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals." The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and includes all available Washington energy efficiency and demand response. The study also removes Yakima and Walla Walla area transmission and relies on increased small-scale renewables.

- **P-SC Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards. This case is identical to the initial P-SC price-policy scenario study conducted among the initial studies. Like the CETA-compliant W-10 CETA portfolio, this sensitivity includes the requirement to use the social cost of greenhouse gases (SC) price-policy assumption in resource acquisition decisions. In

Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA compliant outcomes.

Each of these studies is most pertinent to the State of Washington and are further discussed in Chapter 9 (Modeling and Portfolio Selection Results).

Sensitivity Case Definitions

PacifiCorp identified eight sensitivities outlined in Table 8.13 and discussed further in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).

Table 8.13 – Sensitivity Case Definitions

Case	Description	Load Forecast	Private Generation	Resources	CO_2 Policy
S-01	High Load	High	Low	Optimized	Medium gas / Medium CO_2
S-02	Low Load	Low	High	Optimized	Medium gas / Medium CO_2
S-03	1 in 20 Load Growth	1 in 20	Base	Optimized	Medium gas / Medium CO_2
S-04	20-year Normal	20yr Normal	Base	Optimized	Medium gas / Medium CO_2
S-05	High Private Generation	Base	High	Optimized	Medium gas / Medium CO_2
S-06	Low Private Generation	Base	Low	Optimized	Medium gas / Medium CO_2
S-07	Business Plan	Base	Base	Align first three years	Medium gas / Medium CO_2
S-08	New Load	Flat Load Increase	Base	Optimized	Medium gas / Medium CO_2
W-10	CETA	Base	Base	Added for CETA	WA resources under SC
W-11	Climate Change Counterfactual	No climate change	Base	Optimized	WA resources under SC
W-12	Max Customer Benefit	Base	Base	Modified	WA resources under SC

Load Sensitivities (S01, S02, S03, S04)

PacifiCorp includes four different load forecast sensitivities. The high load forecast sensitivity (S01) reflects optimistic economic growth assumptions from IHS Global Insight, low private generation and the upper bound of the 95% prediction interval for the model error bands. The low load forecast sensitivity (S02) reflects pessimistic economic growth assumptions from IHS Global Insight, high private generation and the lower bound of the 95% prediction interval for the model error bands.

The third load forecast sensitivity (S03) is a 1-in-20 (5 percent probability) extreme weather scenario. The 1-in-20 peak weather scenario is defined as the year for which the peak has the chance of occurring once in 20 years. This sensitivity is based on 1-in-20 peak weather for July in each state. Figure 8.6 compares the low, high, and 1-in-20 load sensitivities, net of base case private generation levels, alongside the base case load forecast.

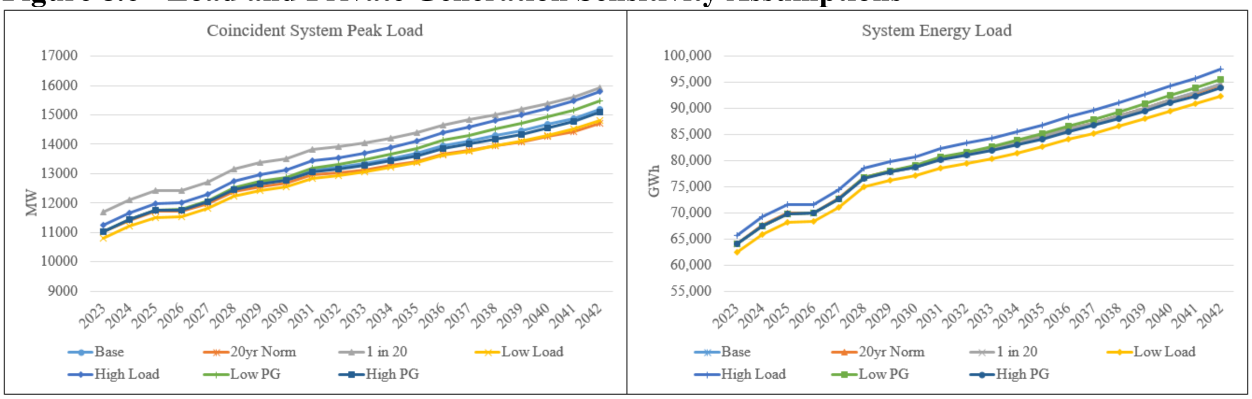
The fourth load forecast sensitivity (S04) is the 20-year normal scenario, which is based on normal weather, which is defined by the 20-year period of 2002 through 2021 (50^{th} percentile). In prior IRP cycles, this scenario is what was traditionally used as the base IRP load forecast.

Private Generation Sensitivities (S05, S06)

Two private generation sensitivities are analyzed. As compared to base private generation penetration levels that incorporated annual reductions in technology costs, the high private generation sensitivity (S05) reflects more aggressive technology cost reduction assumptions, greater technology performance levels, and higher retail electricity rates. In contrast, the low private generation sensitivity (S06) reflects lesser reductions in technology costs, reduced technology performance levels, and lower retail electricity rates.

Business Plan Sensitivity (S07)
Case S07 complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's 2020 Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with those identified in the preferred portfolio. All other resource selections are optimized using the Plexos models.

Figure 8.6 - Load and Private Generation Sensitivity Assumptions



New Load Sensitivity (S08)
PacifiCorp has been approached by customers looking to add a significant volume of new load within PacifiCorp's west balancing authority area. This sensitivity analyzes the level of incremental transmission and new resources that would be needed to meet an incremental 3,000 MW of new load coming online in 2033. The results of this sensitivity will be useful to inform the company's need to initiate planning and permitting activities required to be ready to construct long-lead transmission investments that could be used to reliably serve significant increase in new load. The resource selections from this sensitivity will also provide an indicator of the new resource procurement required to serve these customers. For this sensitivity, incremental transmission and new resource selections are optimized using the Plexos models.

CHAPTER 9 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity maintaining substantial investment in energy efficiency and demand response programs.
- PacifiCorp's selection of the 2023 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process. The preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, advanced nuclear, and non-emitting peaking resources.
- The 2023 IRP preferred portfolio includes new resources from the 2020 All-Source Request for Proposals (RFP). These projects include 1,792 MW of wind, 495 MW of solar additions with 200 MW of battery storage capacity. These resources will come online in the 2024-to-2025 timeframe. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River I (50 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022AS RFP is currently soliciting and evaluating resources to fulfill.
- The 2023 IRP preferred portfolio also includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. By the end of 2032, the preferred portfolio includes 1,000 MW of additional advanced nuclear resources, and through 2037, the preferred portfolio includes 1,240 MW of non-emitting peaking resources. Advancement of these two technologies will be critical to the planned transition of our coal resources in a way that will minimize impacts to our employees and our communities. Over the 20-year planning horizon, the 2023 IRP preferred portfolio includes 9,114 MW of new wind and 7,855 MW of new solar.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the 2023 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2023 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59-mile, high-voltage (230-kilovolt) transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.
- The 2023 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway ("B2H"), which connects the Longhorn substation near the town of Boardman in Oregon to the Hemingway substation in Idaho, which will come online in 2026. By exchanging certain transmission assets with Idaho Power Company, PacifiCorp will receive additional transmission rights between Hemingway and the

Populus substation in Idaho, which is closely tied to existing and future PacifiCorp transmission connecting to Utah and Wyoming. At the Oregon end of the B2H line, additional transmission upgrades are planned to connect B2H to growing loads.

- New since the 2021 IRP, the 2023 IRP preferred portfolio includes a 200-mile high-voltage 500-kilovolt transmission line from Anticline substation in central Wyoming to Populus substation in southeastern Idaho known as Energy Gateway West Sub-Segment D.3, planned to come online in 2028.
- Further, the 2021 IRP preferred portfolio includes near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to serve our customers. New for the 2023 IRP, many of these transmission upgrades and the accompanying resources reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. By evaluating all newly proposed resource additions in an area at the same time, the cluster study process identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. As a result, many of the transmission upgrades and resource additions in the first five years of the IRP preferred portfolio reflect cluster study requests submitted in the past two years.
- Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement or gas conversion of 13 units by 2030 and 20 units by year-end 2032. The final two coal units retire by 2039, or three years ahead of the end of the planning period, with the path to decarbonization supported by new non-emitting technologies.
- In addition to the coal unit exits, retirements, and gas conversions outlined above, the preferred portfolio reflects 2,660 MW natural gas retirements through 2042. This includes Gadsby at the end of 2032, Naughton Units 1, 2, and 3 at the end of 2036, Hermiston at the end of 2036, and Jim Bridger Units 1, 2, 3, and 4 at the end of 2037.
- In the current 2023 IRP emissions are higher than projected in the 2021 IRP until 2032, this is a result of higher load forecast in the 2023 IRP. By 2032, average annual CO_2e emissions are down 21 percent relative to the 2021 IRP preferred portfolio. By 2040 emissions are comparable to the 2021 IRP while generation has increased by 31% showing that the overall emissions rate is lower under 2023 IRP portfolio. By the end of the planning horizon, system CO_2e emissions are projected to fall from 41.5 million metric tons in 2023 to 6.2 million tons in 2042—a reduction of 85 percent

Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the Plexos modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp's preferred portfolio selection process and presents the 2023 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio, cost and risk analysis for the: (1) initial portfolios; (2) the variants of the top performing initial portfolio and (3) the preferred portfolio selection. The final preferred portfolio selection is informed by all relevant modeling results. This chapter also presents modeling results for additional scenarios required under Washington's Clean Energy Transformation Act (CETA)[1].

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp's portfolio evaluation processes. Stochastic modeling results are also summarized in Volume II, Appendix J (Stochastic Simulation Results).

Initial Portfolio Development

The following discussion begins with an examination of initial portfolios exploring variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or carbon capture, utilization and storage (CCUS) retrofit for certain units. The initial portfolios differ based on natural gas and proxy CO_2 policy assumptions, resulting in uniquely optimization combinations of resources, transmission and thermal retirement options.

Following the initial portfolios, PacifiCorp examined variants of the top-performing case with eight additional portfolios referred to as the P-MM variants. All portfolios are examined with a granular assessment of reliability requirements through the production of hourly deterministic ST studies for every year over the 20-year planning horizon. Similar to the initial portfolios, this provides twenty years of hourly ST reliability assessment data used to inform the portfolios and ensure they are reliable.

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), PacifiCorp evaluated eight variants of the top-performing P-MM initial portfolio. Final selection of the top-performing portfolio and preferred portfolio selection also included an assessment of compliance with CETA.

Initial Portfolio Development

The following tables and figures present resource additions and system costs for the initial and variant portfolios. Note that no tables are shown for SCR or CCUS installatioins on coal units. As no SCR or CCUS installations were selected in optimized portfolio, the only studies representing SCR or CCUS are the counterfactual studies for these cases where each technolohy was forced to be built by the model. These counterfactuals are explained in detail later in this chapter.

[1] Due to Washington's IRP and related filing schedules, this 2023 IRP was filed in Washington as PacifiCorp's "Washington 2021 Integrated Resource Plan Two-Year Progress Report". Volume II, Appendix O provides addional detail relevant to Washington requirements.

Table 9.1 – Non-Emiting Peaking (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	-	-	-	-	303	-	-	-	-	1,240	-	-	-	-	-
P-MN		-	-	-	-	-	-	-	-	-	-	-	303	578	345	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P-HH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	951	-	-	-	-	-
P-SC	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	895	-	303	303	-	-	345	289	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P07-D3-D2 32	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	606	-	-	-	-	-	-	289	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	606	-	-	-	-	-	345	1,790	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.2 - DSM Energy Efficiency (Installed Capacity MW)

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	123	220	259	197	216	219	240	258	637	103	160	170	161	281	586	163	170	165	139	412
P-MN	123	220	259	198	217	221	243	259	637	105	160	170	161	288	586	164	170	165	139	412
P-MM	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P-HH	123	220	259	210	229	234	255	266	675	116	161	185	162	289	594	165	187	176	172	671
P-SC	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429
P01-JB3-4 GC	123	220	259	208	228	219	241	259	637	116	163	172	163	288	542	163	183	175	141	428
P02-JB3-4 EOL	123	220	259	208	228	219	240	258	637	115	161	171	161	288	542	163	184	176	141	428
P03-Hunter3-SCR	123	220	259	198	216	220	240	258	637	105	149	170	161	288	586	163	186	176	143	429
P04-Huntington RET28	123	220	259	208	228	219	240	258	637	109	161	171	161	288	542	163	184	176	141	428
P05-No NUC	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429
P06-No Forward Tech	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429
P07-D3-D2 32	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P08-No D3-D2	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P09-No WY OTR	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P10-Offshore Wind	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P11-Max NG	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P12-RET Coal 30 NG 40	123	954	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P13-All EE	123	220	259	289	330	334	392	457	1,016	215	301	283	292	457	816	230	253	241	343	1,231
P14-All GW	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P15-No GWS	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P16-No B2H	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P17-Col3-4 RET25	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P18-Cluster East	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P19-Cluster West	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P20-JB3-4 CCUS	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426

Table 9.3 – DSM Demand Response (Installed Capacity MW)

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	72	39	143	38	161	120	33	16	33	-	-	-	51	-	-	170	19	19	-	-
P-MN	72	39	152	99	126	94	27	13	35	-	-	-	-	-	1	228	19	19	-	-
P-MM	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P-HH	72	39	154	119	117	81	26	-	37	5	13	12	26	-	-	239	22	19	-	-
P-SC	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-
P01-JB3-4 GC	72	220	193	6	83	61	41	10	8	-	-	-	117	-	-	121	21	20	-	-
P02-JB3-4 EOL	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-
P03-Hunter3-SCR	72	53	167	105	111	90	31	13	35	-	-	2	-	-	-	225	19	38	-	-
P04-Huntington RET28	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-
P05-No NUC	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-
P06-No Forward Tech	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-
P07-D3-D2 32	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P08-No D3-D2	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P09-No WY OTR	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P10-Offshore Wind	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P11-Max NG	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P12-RET Coal 30 NG 40	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P13-All EE	72	39	152	109	119	91	29	13	35	-	1	-	2	-	4	265	70	20	-	778
P14-All GW	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P15-No GWS	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P16-No B2H	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P17-Col3-4 RET25	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P18-Cluster East	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P19-Cluster West	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P20-JB3-4 CCUS	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-

Table 9.4 – Renewable Wind (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	194	1,717	-	-	-	500	-	11	5,477	1,821	-	-	-	-	-	-	-	-	-
P-MN	-	194	1,717	-	-	-	500	-	-	6,025	3,565	-	450	-	-	-	-	-	-	-
P-MM	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P-HH	-	194	1,717	-	-	174	500	-	-	7,922	2,321	-	-	-	-	-	-	-	-	-
P-SC	-	194	1,717	-	-	457	500	-	-	6,486	3,607	-	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P02-JB3-4 EOL	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P03-Hunter3-SCR	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P04-Huntington RET28	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P05-No NUC	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P06-No Forward Tech	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P07-D3-D2 32	-	194	1,937	-	100	300	-	-	-	6,165	1,755	-	-	-	-	-	-	-	-	-
P08-No D3-D2	-	194	1,937	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-
P09-No WY OTR	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P10-Offshore Wind	-	194	1,937	-	100	300	1,900	-	-	2,683	1,459	-	-	-	540	-	-	-	-	-
P11-Max NG	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P12-RET Coal 30 NG 40	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	676	-	-	-	-	-
P13-All EE	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P14-All GW	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P15-No GWS	-	194	296	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-
P16-No B2H	-	194	1,937	-	100	-	1,900	400	-	2,783	959	-	-	-	540	-	-	-	-	-
P17-Col3-4 RET25	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P18-Cluster East	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P19-Cluster West	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P20-JB3-4 CCUS	-	194	1,937	-	100	300	1,900	-	-	2,733	1,359	-	-	-	540	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.5 – Renewable Solar (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	1,469	1,600	-	2,519	1,298	-	288	241	-	-	-	-	1,400	-	-	-	-	-
P-MN	-	-	1,469	1,600	-	2,470	1,298	-	254	941	-	-	-	-	600	-	-	-	-	-
P-MM	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P-HH	-	-	1,469	1,600	-	3,006	1,298	-	4	1,288	241	-	-	-	-	-	-	-	-	-
P-SC	-	-	1,469	1,600	-	2,589	1,298	-	108	600	-	841	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P02-JB3-4 EOL	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P03-Hunter3-SCR	-	-	1,469	2,524	483	1,832	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P04-Huntington RET28	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P05-No NUC	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P06-No Forward Tech	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	600	-	-	-	-	-
P07-D3-D2 32	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P08-No D3-D2	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P09-No WY OTR	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P10-Offshore Wind	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P11-Max NG	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P13-All EE	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P14-All GW	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P15-No GWS	-	-	1,469	2,224	483	2,307	600	-	200	972	-	300	-	-	-	-	-	-	-	-
P16-No B2H	-	-	1,469	2,524	483	1,507	600	-	-	972	600	300	-	-	-	-	-	-	-	-
P17-Col3-4 RET25	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P18-Cluster East	-	-	1,469	2,524	483	1,907	2,373	-	-	972	-	300	-	-	-	-	-	-	-	-
P19-Cluster West	-	-	1,469	2,524	483	2,406	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P20-JB3-4 CCUS	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.6 – Battery Storage (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	954	1,600	160	2,008	1,647	-	-	-	400	-	-	-	2,560	-	-	-	-	-
P-MN	-	-	954	1,600	-	2,304	1,647	-	-	600	-	-	-	-	2,356	-	-	-	-	-
P-MM	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P-HH	-	-	954	1,600	-	2,599	1,647	-	-	600	-	-	-	-	1,541	-	-	-	-	-
P-SC	-	-	954	1,600	-	1,979	1,647	-	-	600	-	-	-	-	1,207	-	-	-	-	-
P01-JB3-4 GC	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P02-JB3-4 EOL	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P03-Hunter3-SCR	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P04-Huntington RET28	-	-	954	2,929	628	2,300	1,149	-	-	-	-	-	-	-	100	-	-	-	-	-
P05-No NUC	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-
P06-No Forward Tech	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-
P07-D3-D2 32	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	(196)
P08-No D3-D2	-	-	954	2,929	628	1,900	1,149	-	-	800	150	-	-	-	200	-	-	-	-	-
P09-No WY OTR	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P10-Offshore Wind	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	500	-	-	-	-	-
P11-Max NG	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	1,323	-	-	-	-	(196)
P13-All EE	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P14-All GW	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P15-No GWS	-	-	954	2,629	628	2,500	1,349	-	-	800	150	-	-	-	200	-	-	-	-	-
P16-No B2H	-	-	954	2,929	1,352	1,900	1,149	-	-	-	750	-	-	-	200	-	-	-	-	-
P17-Col3-4 RET25	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P18-Cluster East	-	-	954	2,929	628	1,900	3,322	-	-	-	150	-	-	-	200	-	-	-	-	-
P19-Cluster West	-	-	954	2,929	628	2,399	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P20-JB3-4 CCUS	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.7 – Battery, Long Duration (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P-MN	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P-HH	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P-SC	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	-	-	300	450	-	-	-	200	-	-	-	-	-
P07-D3-D2 32	-	-	600	-	-	-	-	-	-	-	150	-	(600)	-	200	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.8 – Nuclear (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P-HH	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	500	-	-	-	-	-
P-SC	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P07-D3-D2 32	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.9 – Coal End-of-life Retirements[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-MM	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-HH	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-SC	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-
P01-JB3-4 GC	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	(699)	-	(330)	-	-
P02-JB3-4 EOL	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P03-Hunter3-SCR	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P04-Huntington RET28	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P05-No NUC	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P06-No Forward Tech	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P07-D3-D2 32	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P08-No D3-D2	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P09-No WY OTR	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P10-Offshore Wind	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P11-Max NG	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P12-RET Coal 30 NG 40	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P14-All GW	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P15-No GWS	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	(330)	-	-	-	-	-
P16-No B2H	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P17-Col3-4 RET25	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P18-Cluster East	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P19-Cluster West	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P20-JB3-4 CCUS	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-

1 – Negative values indicate retirement of coal fueled capacity

Table 9.10 – Coal with SNCR Installation[1,2]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	2,067	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P-MM	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P-HH	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P-SC	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P01-JB3-4 GC	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P02-JB3-4 EOL	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P03-Hunter3-SCR	-	-	-	1,864	-	-	-	-	-	(418)	(1,178)	-	-	-	-	-	-	(268)	-	-
P04-Huntington RET28	-	-	-	2,335	-	(459)	-	-	-	(418)	(1,190)	-	-	-	-	-	-	(268)	-	-
P05-No NUC	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P06-No Forward Tech	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P07-D3-D2 32	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P08-No D3-D2	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P09-No WY OTR	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P10-Offshore Wind	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P11-Max NG	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P12-RET Coal 30 NG 40	-	-	-	2,067	(450)	-	-	-	-	(418)	(1,199)	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P14-All GW	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P15-No GWS	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	(268)	-	-	-	-	-
P16-No B2H	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P17-Col3-4 RET25	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P18-Cluster East	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P19-Cluster West	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P20-JB3-4 CCUS	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-

1 – Positive values indicate first full year of operations with SNCR installed

2 – Negative values indicate retirement of coal fueled capacity with SNCR

Table 9.11 – Coal to Natural Gas Conversions[1,2]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	713	-	370	598	-	-	699	-	(330)	-	-	-	-	(370)	(1,413)	-	(268)	-	-
P-MN	-	713	-	370	-	-	-	340	(354)	-	-	-	-	(160)	(210)	(699)	-	-	-	-
P-MM	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P-HH	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P-SC	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-
P01-JB3-4 GC	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-
P02-JB3-4 EOL	-	713	-	1,069	-	-	-	-	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P03-Hunter3-SCR	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P04-Huntington RET28	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P05-No NUC	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P06-No Forward Tech	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P07-D3-D2 32	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P08-No D3-D2	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P09-No WY OTR	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P10-Offshore Wind	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P11-Max NG	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P12-RET Coal 30 NG 40	-	713	-	370	598	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	(598)	-	-
P13-All EE	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P14-All GW	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P15-No GWS	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(1,783)	-	-	-	-	-
P16-No B2H	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P17-Col3-4 RET25	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P18-Cluster East	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P19-Cluster West	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P20-JB3-4 CCUS	-	713	-	370	-	-	-	349	-	-	-	-	-	-	(370)	(1,062)	-	-	-	-

1 – Positive values indicate first full year of natural gas-fueled operation

2 – Negative values indicate retirement of gas-converted capacity

Preferred Portfolio Variants

Driven by emergent federal and state law and stakeholder interest, the 2023 IRP features 20 preferred portfolio variants developed to analyze key resource and transmission decisions. This is a 150% increase over the 8 variants represented in the 2021 IRP.[2] The preferred portfolio variants are summarized in Table 9.12.

Table 9.12 – Preferred Portfolio Selection

Portfolio	Description
P01-JB3-4 GC	Early conversion of Jim Bridger 3 & 4 to gas-fired
P02-JB3-4 EOL	Jim Bridger 3 & 4 remain coal-fired through end of life
P03-Hunter3-SCR	SCR installed on Hunter 3 instead of SNCR
P04-Huntington RET28	Early retirement of Huntington 1 in 2028
P05-No NUC	Nuclear selections replaced with non-emitting peakers
P06-No Forward Tech	Nuclear and non-emitting peakers replaced with non-natural gas options
P07-D3-D2 32	Delay D3 and D2.2 transmission until 2032
P08-No D3-D2	Exclude selection of D3 and D2.2 transmission
P09-No WY OTR	Assume Wyoming is not subject to OTR
P10-Offshore Wind	Include offshore wind project
P11-Max NG	Nuclear and non-emitting peakers replaced with natural gas
P12-RET Coal 30 NG	Retire all coal by year-end 2029; retire all natural gas by year-end 2039
P13-All EE	Includes all energy efficiency programs
P14-All GW	Includes all Energy Gateway transmission segments
P15-No GWS	Exclude Energy Gateway South
P16-No B2H	Exclude selection of B2H transmission
P17-Col3-4 RET25	Colstrip units 3 and 4 retire end of 2025
P18-Cluster East	Enable Cluster 1 Areas 5, 6, and 7: resources and transfer capability in Clover, Utah.
P19-Cluster West	Enable Cluster 1 Area 12: resources and transfer capability in southern Oregon.
P20-JB3-4 CCUS	JB3-4 converts to CCUS in 2028

Preferred Portfolio Variants Discussion

[2] In addition to more than doubling the number of variants, these studies also represent a sea change in optimization complexity. In particular, the Ozone Transport Rule's (OTR) recursive nature complicates model math and performance. The OTR and Inflation Reduction Act together represent many hundreds of pages of detail, and PacifiCorp is highly confident that modeling requirements will evolve significantly as these policy changes are absorbed by the energy industry.

Table 9.13 – Initial and Variant Cases Under Medium Gas/ Medium CO2

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - MM	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P-MM	37,438	$0	3	37,305	$0	3	0.0020%	0.00000%	12	330,442	0	11
P01-JB3-4 GC	38,031	$593	8	37,903	$598	8	0.0012%	-0.00080%	1	323,314	-7,128	4
P02-JB3-4 EOL	38,503	$1,065	11	38,358	$1,052	10	0.0012%	-0.00076%	3	342,026	11,584	14
P03-Hunter3-SCR	37,705	$267	6	37,562	$257	6	0.0019%	-0.00008%	5	346,847	16,404	15
P04-Huntington RET28	37,598	$160	5	37,465	$160	4	0.0012%	-0.00079%	2	328,688	-1,754	9
P05-No NUC	39,086	$1,648	17	39,208	$1,903	18	0.0015%	-0.00051%	4	355,234	24,792	17
P06-No Forward Tech	38,771	$1,333	13	38,876	$1,570	13	0.0019%	-0.00006%	6	353,676	23,233	16
P07-D3-D2 32	37,419	($19)	2	37,235	($70)	2	0.0020%	-0.00004%	7	331,885	1,442	13
P08-No D3-D2	39,212	$1,774	19	39,228	$1,923	19	0.0020%	0.00002%	16	361,637	31,195	18
P09-No WY OTR	36,808	($630)	1	36,632	($673)	1	0.0020%	-0.00004%	8	362,623	32,181	19
P10-Offshore Wind	38,770	$1,333	12	39,018	$1,713	15	0.0020%	0.00004%	18	327,328	-3,114	8
P11-Max NG	38,342	$904	10	38,466	$1,161	11	0.0029%	0.00095%	21	369,404	38,962	20
P12-RET Coal 30 NG 40	41,263	$3,825	21	41,209	$3,904	21	0.0020%	0.00002%	17	268,786	-61,657	1
P13-All EE	40,613	$3,175	20	40,449	$3,143	20	0.0020%	-0.00001%	10	321,444	-8,998	3
P14-All GW	37,998	$560	7	37,865	$560	7	0.0020%	0.00000%	11	330,335	-108	10
P15-No GWS	38,975	$1,537	15	39,128	$1,822	17	0.0023%	0.00036%	19	383,310	52,867	21
P16-No B2H	39,156	$1,718	18	39,022	$1,716	16	0.0020%	-0.00002%	9	323,894	-6,548	5
P17-Col3-4 RET25	37,511	$73	4	37,511	$206	5	0.0020%	0.00000%	13	326,893	-3,550	7
P18-Cluster East	39,004	$1,566	16	39,004	$1,699	14	0.0020%	0.00001%	14	307,849	-22,593	2
P19-Cluster West	38,075	$637	9	38,075	$770	9	0.0020%	0.00001%	15	324,730	-5,713	6
P20-JB3-4 CCUS	38,781	$1,343	14	38,649	$1,344	12	0.0024%	0.00045%	20	330,442	0	11

Table 9.14 – Initial and Variant Cases Under Low Gas/ Zero CO2

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - LN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P-MM	36,181	$0	2	36,155	$0	2	0.0020%	0.00000%	5	306,945	0	3
P-LN	34,650	($1,532)	1	34,610	($1,545)	1	0.0019%	-0.00014%	4	296,748	-10,197	1
P02-JB3-4 EOL	37,004	$822	5	36,966	$811	4	0.0009%	-0.00106%	1	318,019	11,074	4
P11-Max NG	36,503	$322	3	36,731	$576	3	0.0028%	0.00078%	6	342,480	35,535	5
P16-No B2H	37,102	$920	6	37,070	$915	5	0.0017%	-0.00029%	2	301,689	-5,257	2
P15-No GWS	36,848	$667	4	37,088	$934	6	0.0019%	-0.00014%	3	355,714	48,769	6

Table 9.15 – Initial and Variant Cases Under Medium Gas/ Zero CO2

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - MN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P-MM	36,257	$0	2	36,252	$0	2	0.0020%	0.00000%	2	313,970	0	2
P-MN	35,868	($390)	1	35,726	($526)	1	0.0020%	-0.00004%	1	304,970	(9,000)	1

Table 9.16 – Initial and Variant Cases Under High Gas/ High CO2

Case - HH	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P-MM	45,540	($1,286)	2	45,540	($1,286)	2	0.0020%	0.00105%	4	328,142	-19,555	3
P11-Max NG	48,092	$1,266	5	48,092	$1,266	5	0.0025%	0.00159%	6	355,494	7,798	5
P02-JB3-4 EOL	46,826	$0	4	46,826	$0	4	0.0009%	0.00000%	1	347,697	0	4
P15-No GWS	49,776	$2,949	6	49,776	$2,949	6	0.0018%	0.00091%	3	358,984	11,288	6
P16-No B2H	46,267	($559)	3	46,267	($559)	3	0.0017%	0.00075%	2	324,186	-23,511	2
P-HH	43,782	($3,045)	1	43,782	($3,045)	1	0.0020%	0.00105%	5	305,285	-42,412	1

Jim Bridger Unit 3 and Unit 4 Early Gas Conversion Variant (P01-JB 3-4 GC)

The Jim Bridger 3 and 4 Early Gas Conversion variant changes the conversion date of the Bridger 3 and 4 plants from 2030 to 2026. This variant explores the potential costs or benefits of converting these units to gas earlier, taking into consideration current sunk costs and differences between projected future coal and gas prices.

Figure 9.1 shows the cumulative (at left) and incremental (at right) portfolio changes when these plants convert four years earlier in 2026 compared to the P-MM base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. Since Jim Bridger 3 and 4 continue to operate in both scenarios, just with different fuels, there are only relatively small changes in this portfolio in energy efficiency and demand response.

Figure 9.1 - Increase/(Decrease) in Proxy Resources when Jim Bridger is Gas Converted in 2026 versus 2030

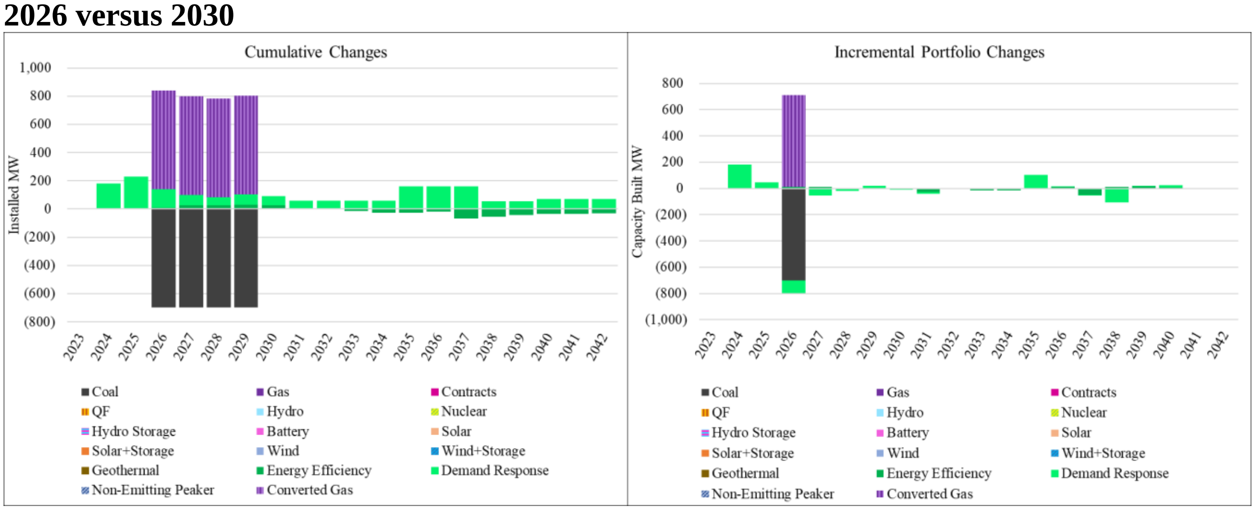
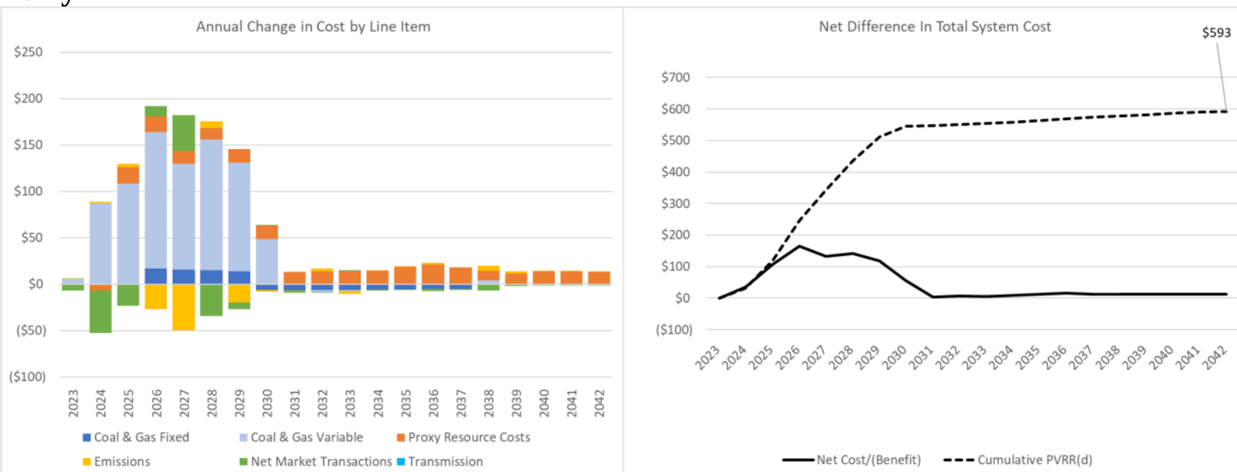


Figure 9.**Figure 9.1 - Increase/(Decrease) in Proxy Resources when Jim Bridger is Gas Converted in 2026 versus 2030**
2 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the timing of the Jim Bridger 3 and 4 Gas Conversion changes. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that converting the units in 2026 is $589 million higher cost than the P-MM Portfolio. On a risk-adjusted basis, which factors

in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio with the early gas conversion of these units is $593 million higher cost than the P-MM portfolio.

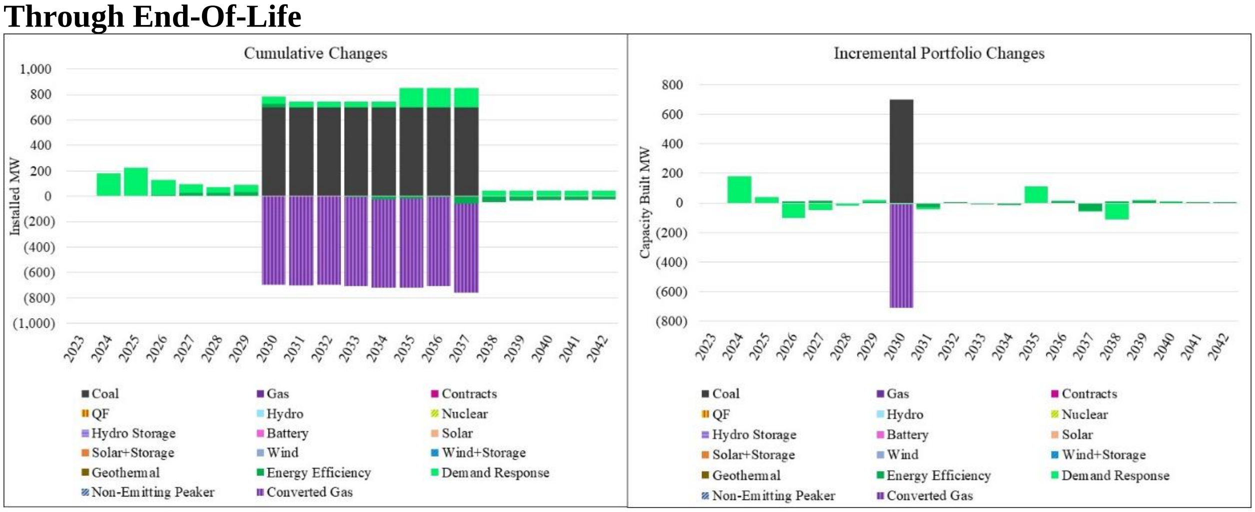
Figure 9.2 Increase/(Decrease) in System Costs when Bridger 3 and 4 Plants Gas Convert Early



Jim Bridger Unit 3 and Unit 4 Remain Coal-Fired through End of Life Variant (P02-JB 3-4 EOL)
The Jim Bridger 3 and 4 Remain Coal-Fired through End of Life variant excludes gas conversion of the Bridger 3 and 4 plants and has them continue operation to their end of life in 2037. This variant explores the potential cost or benefits of keeping these units operating on coal until their end of life, taking into consideration current sunk costs and projected future coal prices.

Figure 9.3 shows the cumulative (at left) and incremental (at right) portfolio changes if these plants continue operating as coal until their end of life at year end 2037 compared to the P1-MM base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. As with the prior variant, Jim Bridger 3 and 4 continue to operate in both scenarios, just with different fuels, so there are only relatively small changes in this portfolio in energy efficiency and demand response.

Figure 9.3 - Increase/(Decrease) in Proxy Resources when Jim Bridger Runs as Coal Through End-Of-Life



Fgure 9.4 Figure 9.4 - Increase/(Decrease) in System Costs when Jim Bridger Runs as Coal Through End-Of-Life

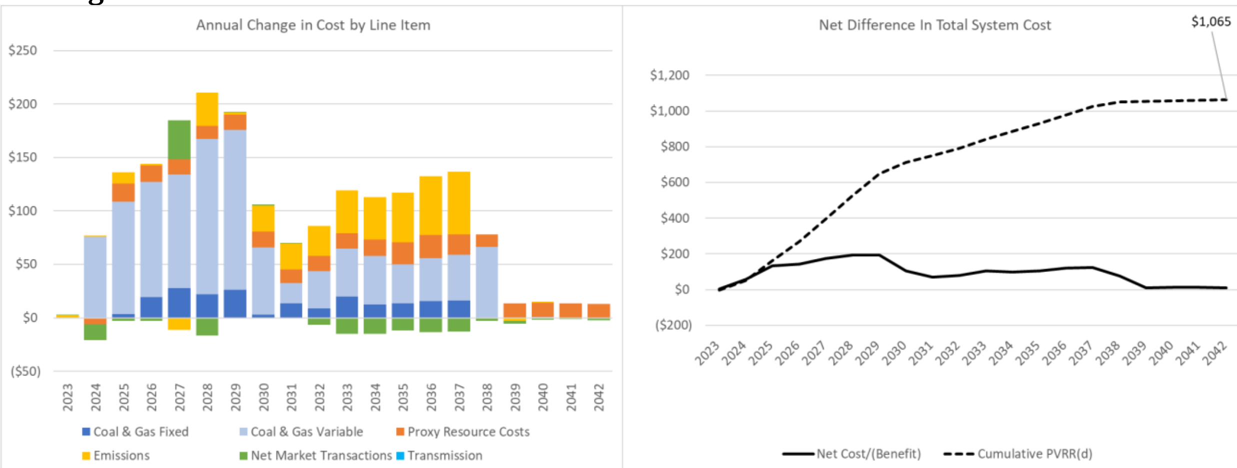
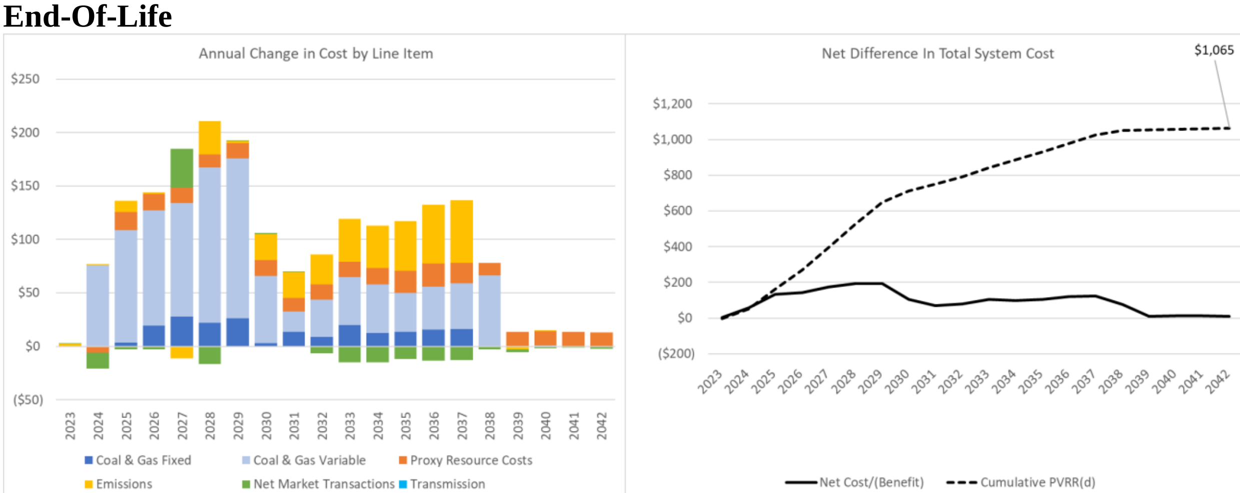


Figure 9.4 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Jim Bridger 3 and 4 Operate as coal through end of life. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that running the Bridger units as coal is $1.07 billion higher cost than the P-MM Portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio running the Bridger units as coal through the end of life is $1.05 billion higher cost than the P-MM portfolio. These costs are primarily driven by higher coal fuel and fixed costs.

Figure 9.4 - Increase/(Decrease) in System Costs when Jim Bridger Runs as Coal Through End-Of-Life



Hunter Unit 3 SCR Installed Instead of SNCR Variant (P03-Hunter SCR)

The Hunter 3 SCR variant evaluates selection of SCR technology over SNCR technology at the Hunter 3 coal unit. This variant also extends the retirement date of the Hunter 3 plant from 2032 through its end of life in 2042. This variant explores the potential impact to emissions compliance and cost or benefits of utilizing a different emissions mitigation technology to this unit.

Figure 9.5 shows the cumulative (at left) and incremental (at right) portfolio changes if the Hunter 3 plant continues operating until its end of life with an SCR compared to the P-MM base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. In this case, the inclusion of Hunter 3 with an SCR causes a reduction in solar which is sited at the Hunter locations as a surplus resource. Given the implications of OTR compliance, there are no other resource reductions in this case, as coal operations are limited during high need times in the summer, and firm, non-emitting resources are still needed. The balance of the changes in this portfolio are related to energy efficiency and demand response.

Figure 9.5 - Increase/(Decrease) in Proxy Resources when Hunter 3 runs as SCR Through its End-of-Life

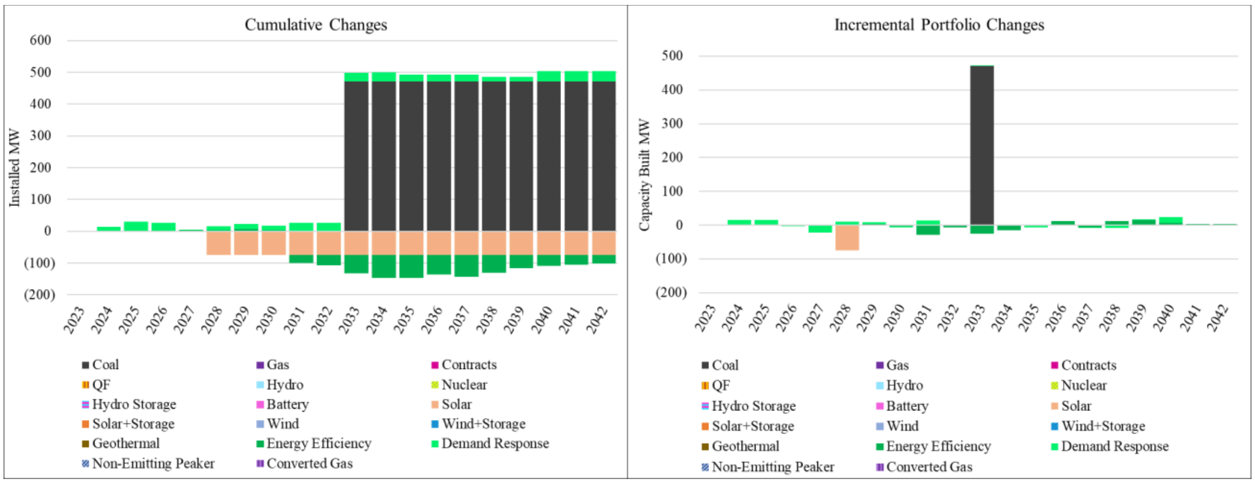
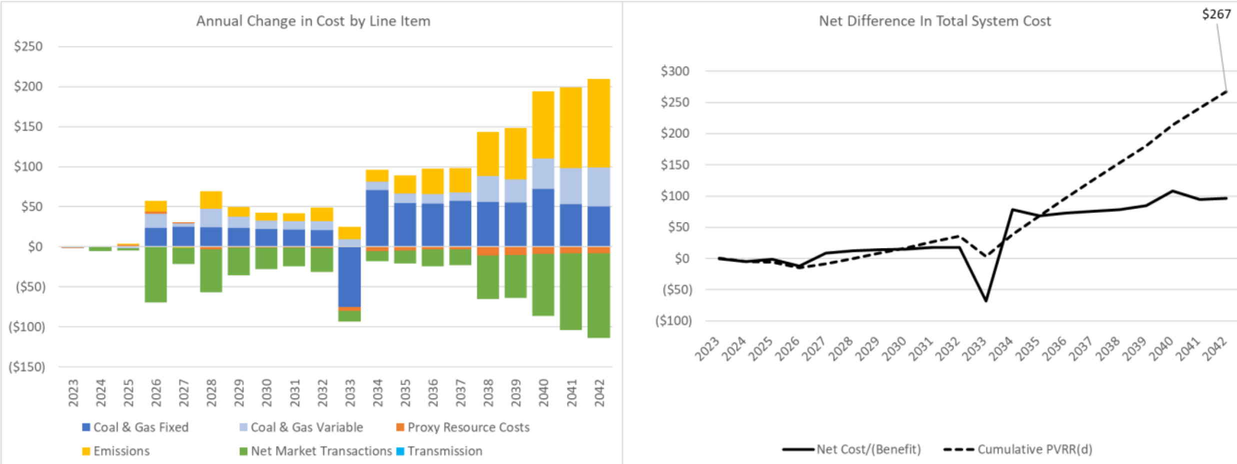


Figure 9.6 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Hunter 3 operates as coal with an SCR through end of life. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that running Hunter 3 as coal with SCR is $257 million higher cost than the P-MM Portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio running the Hunter 3 with SCR through the end of life is $267 million higher cost than the P-MM portfolio. The lower market reliance costs in this case are fully offset by coal fuel and emissions costs.

Figure 9.6 - Increase/(Decrease) in System Costs when Hunter 3 runs as SCR Through its End-of-Life



Huntington Unit 1 Early Retirement in 2028 Variant (P04-Huntington RET28)

The Huntington 1 Early Retirement variant evaluates shifting the date of the Huntington 1 plant retirement from the end of 2032 to the end of 2028. This variant explores the potential impact to the system of removing firm capacity early in the study and replacing this with non-emitting technology. This study seeks to identify potential risks from closing this coal plant earlier than in the P-MM portfolio.

Figure 9.7 shows the cumulative (at left) and incremental (at right) portfolio changes if the Huntingotn 1 plant were to cease operations at the end of 2028 compared to the P-MM base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. In this case, the earlier retirement of the Huntington 1 plant prompts the acceleration of 400 MW of storage from 2033 and 2037 into 2028. Additionally, the acceleration is limited to four hour storage versus the inclusion of some long duration storage. High surplus builds at the hunter and Huntington sites through 2032 mean storage is the needed solution versus additional generating resources. The balance of the changes in this portfolio are related to energy efficiency and demand response.

Figure 9.7 - Increase/(Decrease) in Proxy Resources when Huntington 1 Retires End of 2028

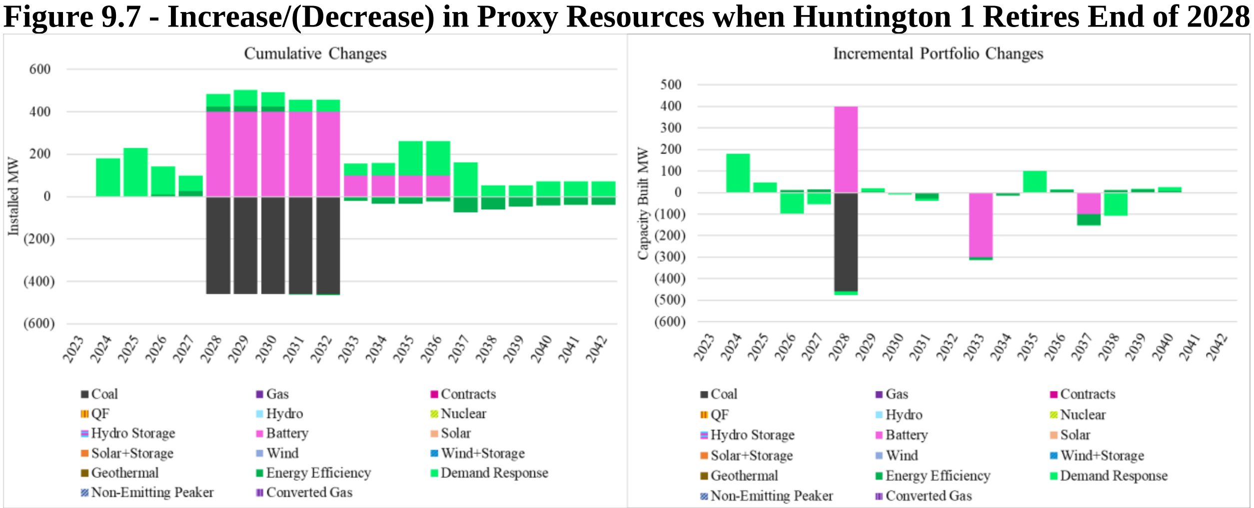
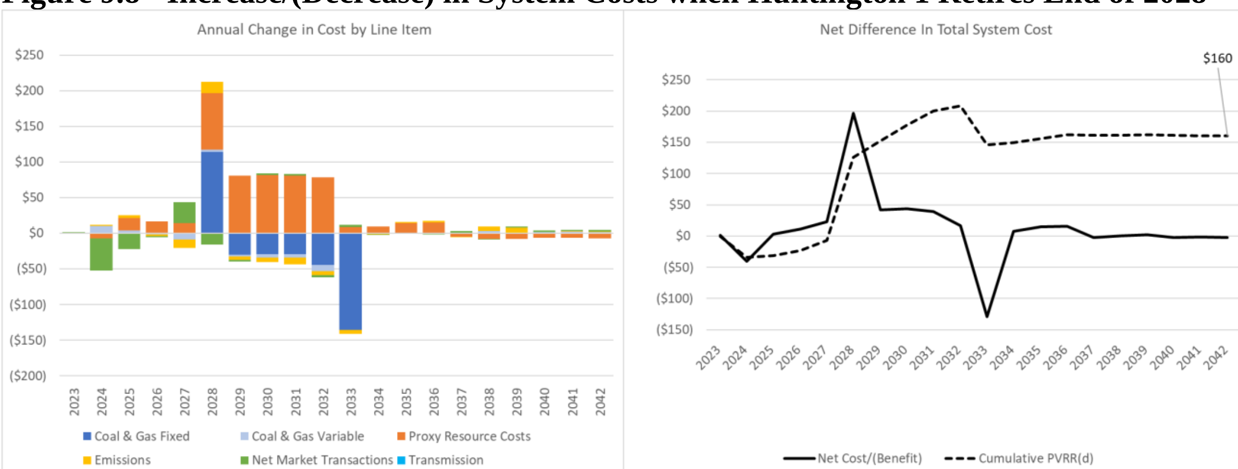


Figure 9.8 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Huntington 1 retires at the end of 2028. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that retiring Huntington 1 early at the end of 2028 is $160 million higher cost than the P-MM Portfolio. These two portfolios had a risk adjustment that, when added to the total PVRR, rounded to the same figure, so on a risk-adjusted basis, the PVRR(d) remains a $160 million higher cost than the P-MM portfolio. The early retirement of Huntington 1 has lower fixed coal costs and lower emissions. This figure is offset by the higher proxy capital costs caused by accelerating builds into the highest part of the supply side cost curve.

Figure 9.8 - Increase/(Decrease) in System Costs when Huntington 1 Retires End of 2028



Nuclear Selections Replaced with Non-Emitting Peakers Variant (P05-No NUC)

The P05-No Nuc portfolio is a variant of the P1-MM portfolio that eliminates the Natrium™ advanced nuclear demonstration project and any future nuclear projects. When this variant is compared to the PA1-MM portfolio, changes in proxy resources and system costs driven by the removal of nuclear projects can be isolated.

Figure 9.9 shows the cumulative (at left) and incremental (at right) portfolio changes when all nuclear projects are eliminated from the P1-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. Without the Natrium™ demonstration project, 289 MW of non-emitting peaking resource is added to the portfolio in 2030. Gas plants at the Naughton site were assumed to continue operation to backfill the Natrium project during any outages, and in a no Natrium scenario are relied upon more heavily. In 2032 303 MW of non-emitting peaking resource and 200 MW of battery storage are added at Hunter in replacement of the advanced nuclear plant in P-MM. This selection is duplicated in 2033. The balance of changes in the portfolio are demand response and energy efficiency related.

Figure 9.9 – Increase/(Decrease) in Proxy Resources when Nuclear Projects are Eliminated from the P1-MM portfolio.

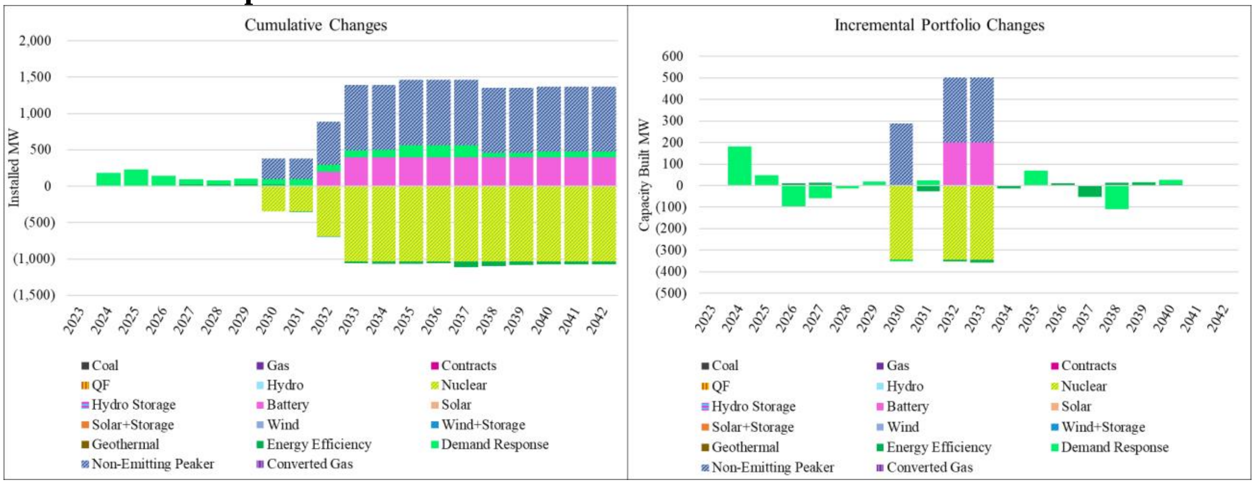
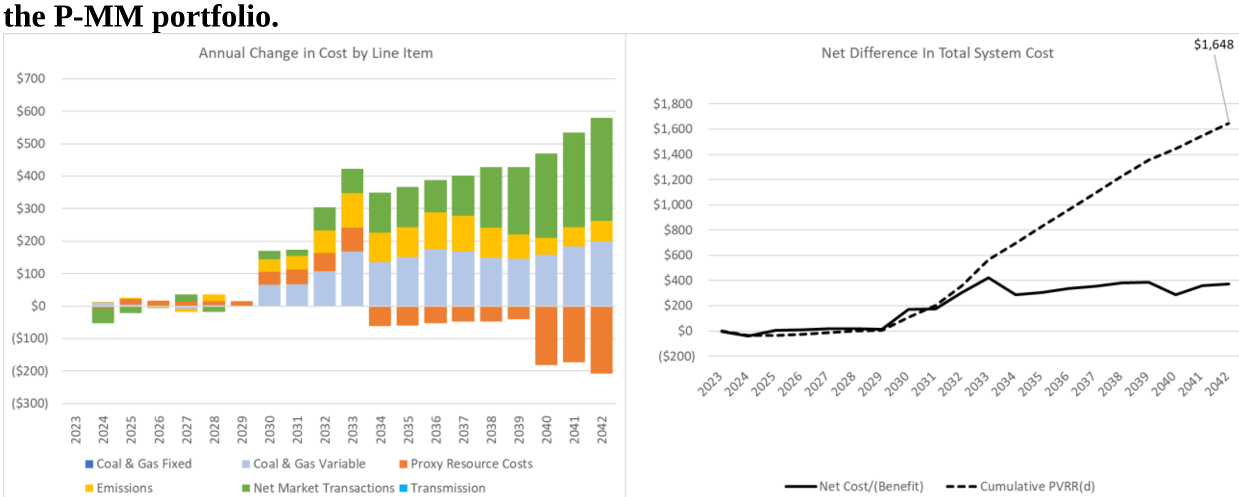


Figure 9.10 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the Natrium™ demonstration project and other nuclear projects are eliminated from the P1-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio without nuclear projects is \$1.65 billion higher cost than the P1-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without nuclear resources is \$1.90 million higher cost than the P-MM portfolio.

When the advanced nuclear projects are removed from the portfolio, the cost for new proxy resources decreases overall as the replacement options have lower capital costs. However, higher ongoing variable and fuel costs at peaking resources, and higher emissions costs more than offsets any reduced capital savings garnered by eliminating nuclear plants from the portfolio.

Figure 9.10 Increase/(Decrease) in System Costs when Nuclear Projects are Eliminated from the P-MM portfolio.



Nuclear and Non-Emitting Peakers Replaced with Non-Gas Options Variant (P06-No Forward Tech)

The P06-No Forward Tech portfolio is a variant of the P1-MM portfolio that eliminates all future resource options which are not currently available within the existing PacifiCorp portfolio. When this variant is compared to the P1-MM portfolio, changes in proxy resources and system costs driven by the removal of all future technology types can be isolated.

Figure 9.11 shows the cumulative (at left) and incremental (at right) portfolio changes when all future technology projects are eliminated from the P1-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. Without any future technology, long duration storage and four hour battery stoage are added at Hunter and Huntington in 2032 and 2033 respectively. These sites also house large surplus solar builds meaning that the addition of a mix of long duration and four hour battery for reliability is sufficient. Gas plants at the Naughton site were assumed to continue operation until the end of life, being replaced by 600 MW of solar resources in 2037. The balance of changes in the portfolio are demand response and energy efficiency related.

Figure 9.11 – Increase/(Decrease) in Proxy Resources when all Future Technology is Eliminated from the P1-MM Portfolio.

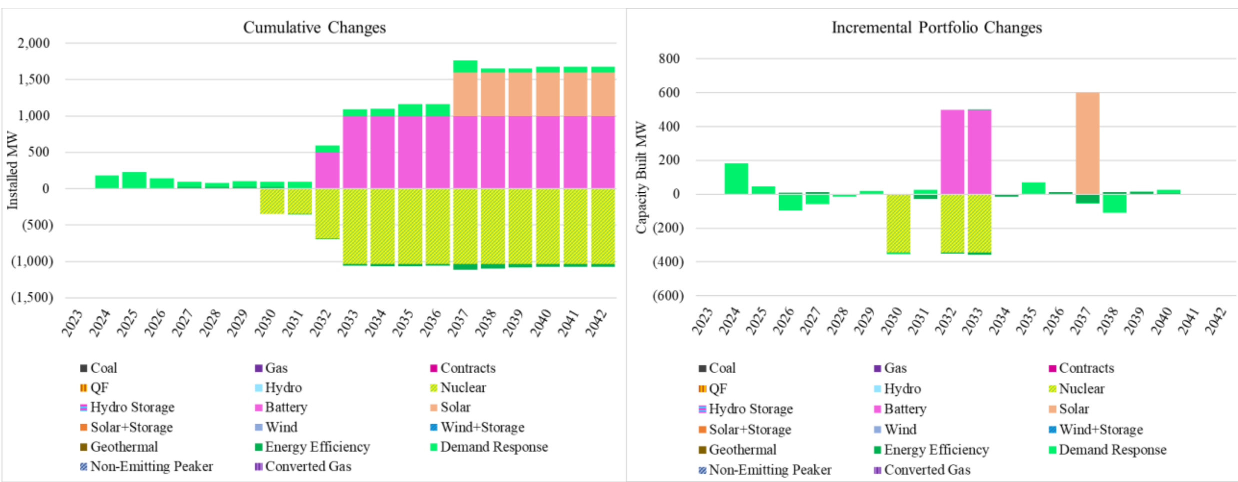
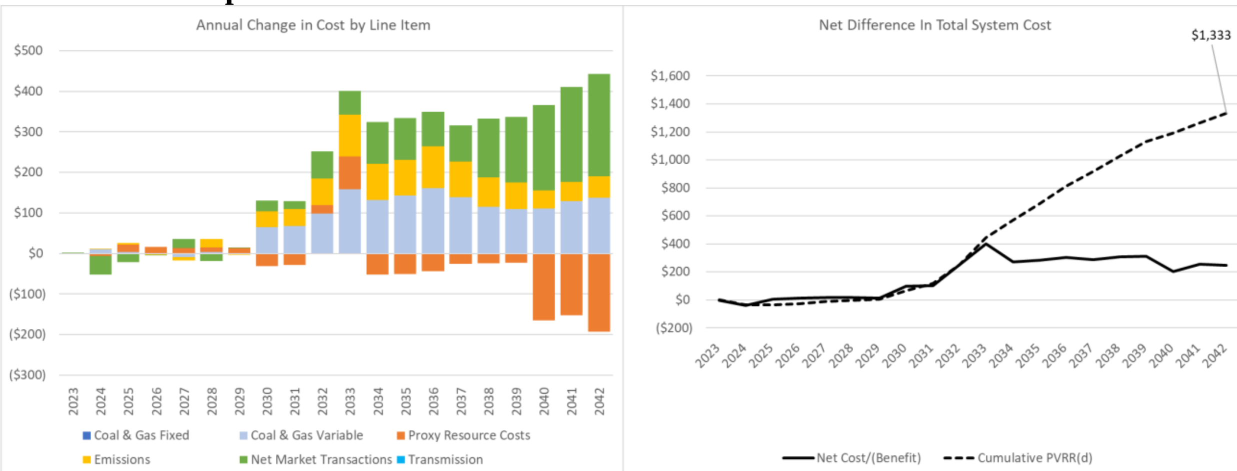


Figure 9.12 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when all future technology is eliminated from the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio without future technology is $1.34 billion higher cost than the P1-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without future technology is $1.57 billion higher cost than the P-MM portfolio.

When the future technology project is removed from the portfolio, new proxy FOM and capital costs decrease overall. However, significantly higher fuel and emissions costs, plus greater reliance on markets to maintain reliability more than offsets any savings garnered by eliminating the generally higher upfront costs of future technology from the portfolio.

Figure 9.12 – Increase/(Decrease) in System Costs when Future Technology is Eliminated from the P-MM portfolio.



D3 and D2.2 Transmission Delayed Until 2032 Variant (P07-D3 32)

The P07-D3 32 portfolio is a variant of the P-MM portfolio that evaluates the impact a delay in the timing of D2.2 and D3 has on the portfolio. When this variant is compared to the P-MM portfolio, changes in proxy resources and system costs driven by the delay in both transmission and resource selection can be isolated.

Figure 9.13 shows the cumulative (at left) and incremental (at right) portfolio changes when the D2.2 and D3 transmission projects are delayed to 2032. 600 MW of storage is shifted from 2035 into 2025 in this case in order to meet reliability needs in the interval where D2.2 and D3 are not built. Additional battery is built in 2027, and wind projects are delayed from 2029 to 2032. This portfolio selects a total of 1,337 MW of additional wind when compared to the P-MM study. Wind selections are grouped all into 2032 and 2033 due to the timing of the transmission projects.

Figure 9.13 - Increase/(Decrease) in Proxy Resources when D2.2 and D3 are delayed to 2032

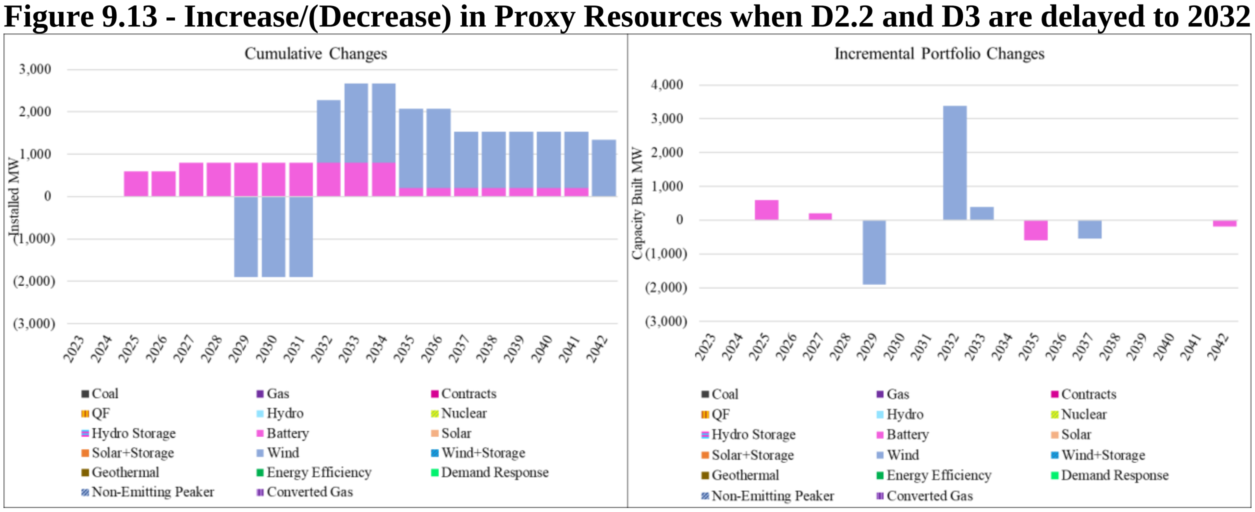
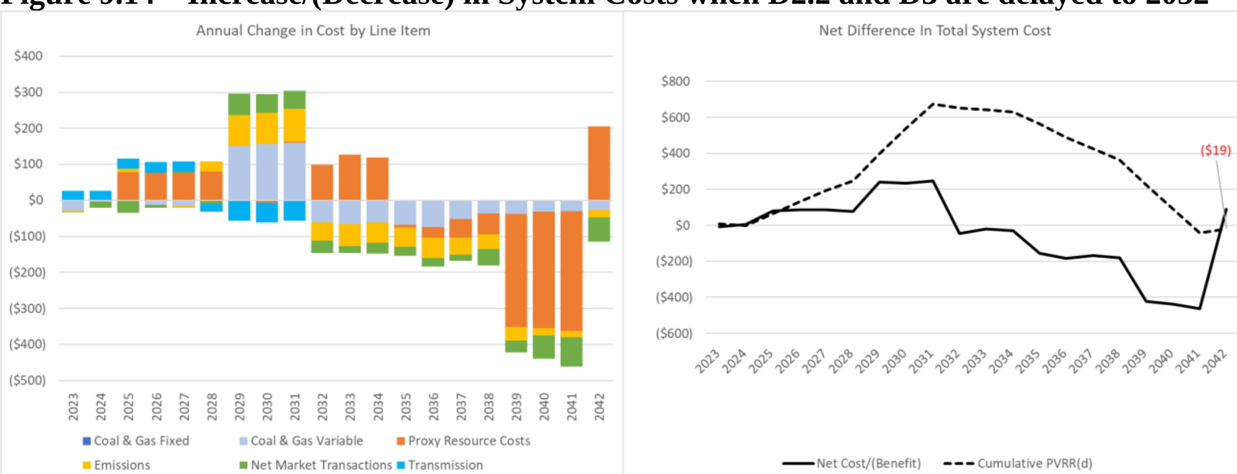


Figure 9.14 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the transmission selection changes from the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system

costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio delaying D2.2 and D3 is $19 million lower cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio delaying D2.2 and D3 is $70 million lower cost than the P-MM portfolio. Much of the cost differential is a result of the Company's forecast of significant declines in wind resource build costs between 2029 and 2032. Because the potential benefits are largely based on cost declines which may occur earlier or not at all, rather than the specific operating characteristics of these portfolios, it is appropriate to look for opportunities to procure lower cost resources on an earlier timeframe.

Higher total proxy resource costs as a result of a larger resource build are offset in this case by lower emissions and less reliance on the market. Having a larger amount of wind in the portfolio is also a benefit to the case delaying D2.2 and D3 as this portfolio has higher late PTC levels than P-MM. The D2.2 and D3 delay case also has higher early reliance on energy storage, which may or may not be feasible. Additionally, interconnection or transmission service requests could trigger a portion of these transmission upgrades earlier than 2032, which is not wholly in the control of the Company.

Figure 9.14 – Increase/(Decrease) in System Costs when D2.2 and D3 are delayed to 2032



Excluded Selection of D3 and D2.2 Transmission Variant (P08-No D3-D2)

The P08-No D2-D3 portfolio is a variant of the P-MM portfolio that evaluates the impact excluding D2.2 and D3 from selection has on the portfolio. When this variant is compared to the P-MM portfolio, changes in proxy resources and system costs driven by the elimination of these transmission lines and the impact to renewable resources which rely on these lines lines can be evaluated.

Figure 9.15 shows the cumulative (at left) and incremental (at right) portfolio changes when the D2.2 and D3 transmission projects are eliminated from the portfolio. 1,900 MW of wind is no longer eligible to come online in 2029 and is removed from the portfolio. An additional removal of 435 MW of wind in 2032 is offset by 1,400 MW of storage, 600 MW of which is long duration storage. In 2037, another 540 MW of wind is removed from the portfolio. 1,000 MW of advanced nuclear plants are sited at existing coal sites to offset the Wyoming wind which was no longer eligible for selection in the absence of the increased interconnection capability associated with these transmission projects.

Figure 9.15 - Increase/(Decrease) in Proxy Resources when D2.2 and D3 are Excluded

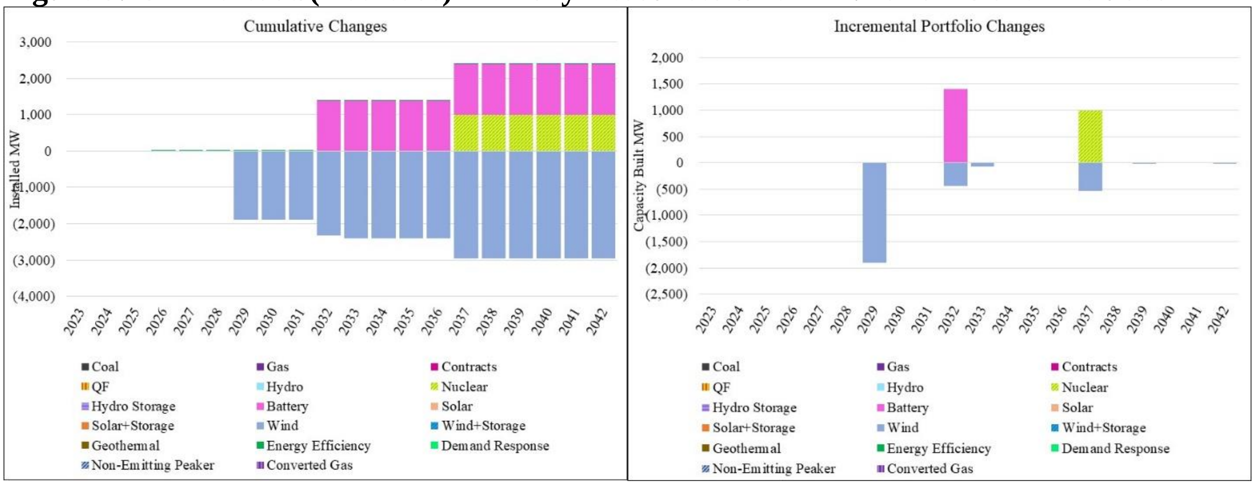
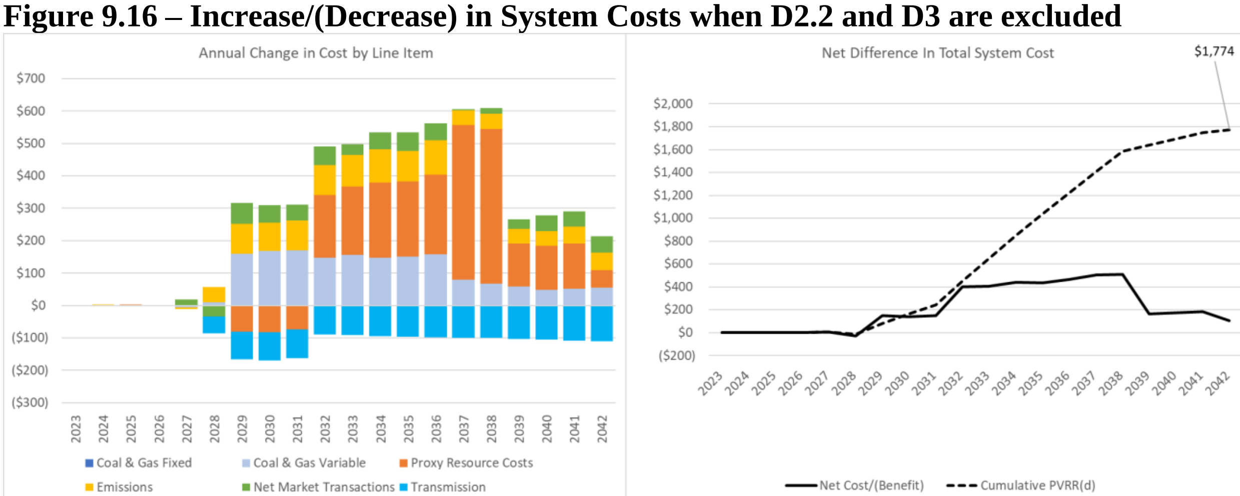


Figure 9.16 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the D2.2 and D3 are excluded from the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio excluding D2.2 and D3 is $1.77 billion higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio excluding D2.2 and D3 is $1.92 billion higher cost than the P-MM portfolio.

The significant reduction in early proxy capital costs and transmission costs is overtaken by higher fuel costs (both coal and gas), as well as significant emissions costs. Additionally, the loss of Production Tax Credit generating renewable resources results in much higher overall renewables variable costs in the study which excludes D2.2 and D3. Finally, an increased reliance on the market also contributes to higher overall costs in this case.

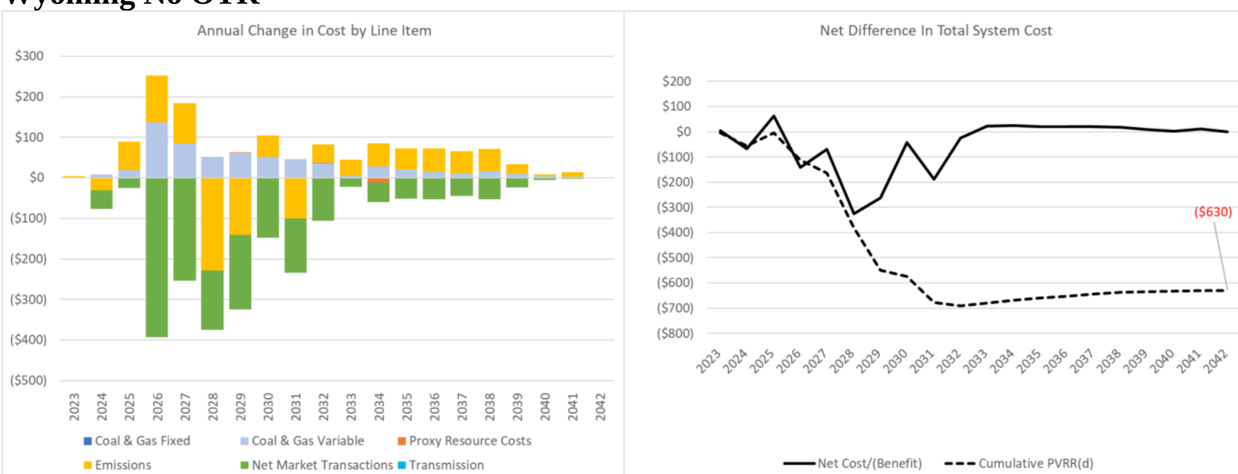
Figure 9.16 – Increase/(Decrease) in System Costs when D2.2 and D3 are excluded



Assume Wyoming is not Subject to OTR Variant (P09-No WY OTR)
This variant does not change resource selections from that assumed in the preferred portfolio, but instead removes the federal Ozone Transport Rule (OTR) compliance obligation for thermal resources located in the state of Wyoming.

Figure 9.17 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when OTR considerations are eliminated from the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio operation without Wyoming OTR restrictions is $630 million lower cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, system dispatch without Wyoming OTR compliance obligations is $673 million lower cost than the P1-MM portfolio.

Figure 9.17 – Increase/(Decrease) in System Costs of P-MM Portfolio Operating Under Wyoming No OTR



Inclusion of Offshore Wind Project Variant (P10-Offshore Wind)
The P10-Offshore Wind portfolio is a variant of the P-MM portfolio that forces in a minimum of 1000 MW of offshore wind in southern Oregon. As offshore wind was not selected in any initial portfolio runs, regardless of price variant, this study seeks to evaluate whether offshore wind would be a cost or benefit to the system. P-MM does select resources in southern Oregon which necessitate the transmission option that enables offshore wind, so the variations in this study are all generator specific and not impacted by transmission choices.

Figure 9.18 shows the cumulative (at left) and incremental (at right) portfolio changes when offshore wind is selected in the P-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. With offshore wind added to the portfolio there is a one year delay of 100 MW of wind in southern Oregon. This delay consolidates the P-MM southern Oregon wind build from two years into one year, once the transmission project which enables offshore wind comes online. The southern Oregon non-emitting peaking resource which was selected in P-MM is replaced by 300 MW of 4 hour battery in 2037.

Figure 9.18 – Increase/(Decrease) in Proxy Resources when Offshore Wind is Added to the P-MM Portfolio.

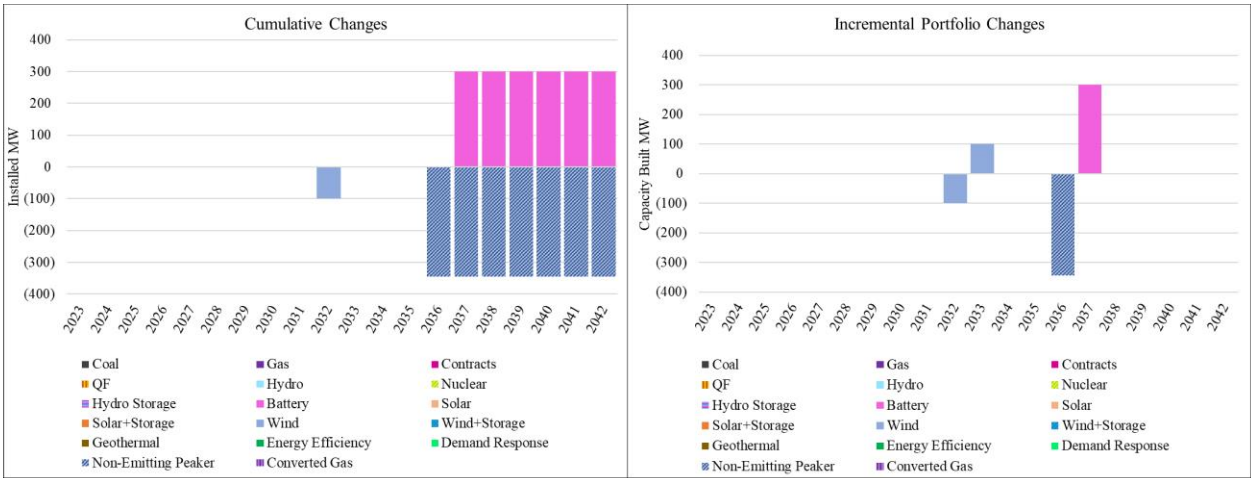
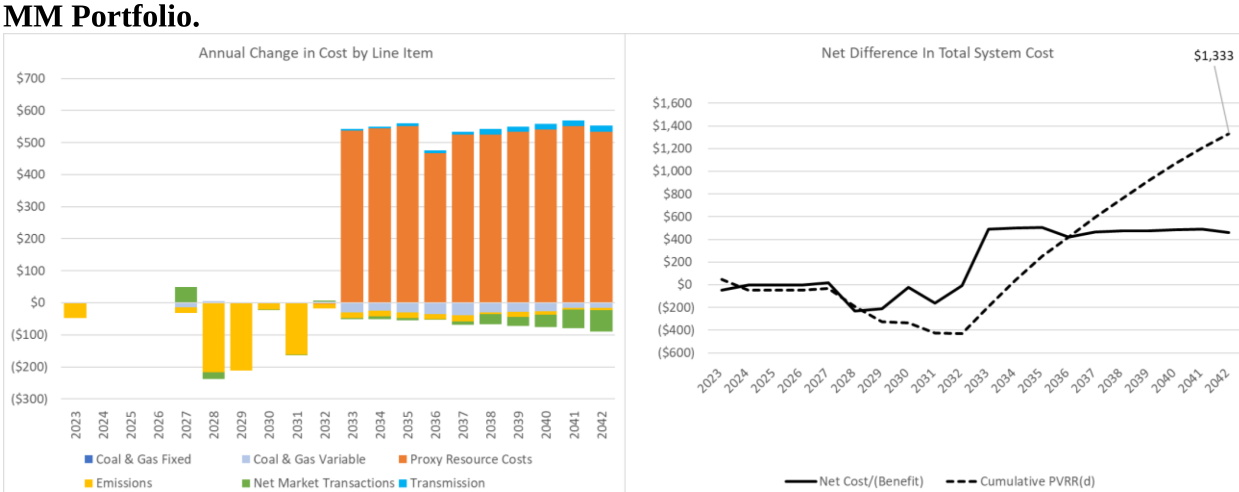


Figure 9.19 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when all future technology is eliminated from the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio without future technology is $1.34 billion higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the demonstration project is $1.71 billion higher cost than the P-MM portfolio.

When offshore wind is added to the portfolio, new proxy FOM and capital costs decrease overall. However, significantlyhigher fueland emissions costs, plus greater reliance on markets to maintain reliability more than offsets any savings garnered by eliminating the generally higher upfront costs of future technology from the portfolio.

Figure 9.19 – Increase/(Decrease) in System Costs when Offshore Wind is Added to the P-MM Portfolio.



Nuclear and Non-Emitting Peakers Replaced with Natural Gas Variant (P11-Max NG)
The P11-Max NG Variant portfolio is a variant of the P-MM portfolio that assumes natural gas peaking resources are the only option to replace coal capacity as it retires. The cost to build pipelines to all current coal sites may be prohibitive, so in cases where that cost is too great, alternative sites for natural gas fueled generators were considered. When this variant is compared to the P-MM portfolio, changes in proxy resources and system costs driven by the exclusive use of natural gas fueled replacement resources can be isolated.

Figure 9.20 shows the cumulative (at left) and incremental (at right) portfolio changes natural gas fueled generators replace coal generation in the P-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. Limiting the model from selecting future technology and replacing those options with natural gas fueled resources result in the removal of 1500 MW of advanced nuclear plants in 2030, 2032 and 2033, and non-emitting peaking resources in 2030. 303 MW of the non-emitting peaking resource is not eligible to be replaced in the portfolio by natural gas fueled items as it was built in Oregon which does not allow for natural gas fueled generation in 2030. These removals of nuclear and non-emitting peaking resources are replaced by 1,044 MW of natural gas combined cycle plants in 2032. An additional 500 MW of combined cycle plants is built in 2037 and another 522 MW in 2040. Duct firing technology is added to the 500 MW units built in 2037 bringing total natural gas fueled additions to 2,349 MW during the study versus nuclear and non-emitting peaking removals of 2,740 MW.

Figure 9.20 – Increase/(Decrease) in Proxy Resources when Gas Replaces Future Technology in the P-MM Portfolio.

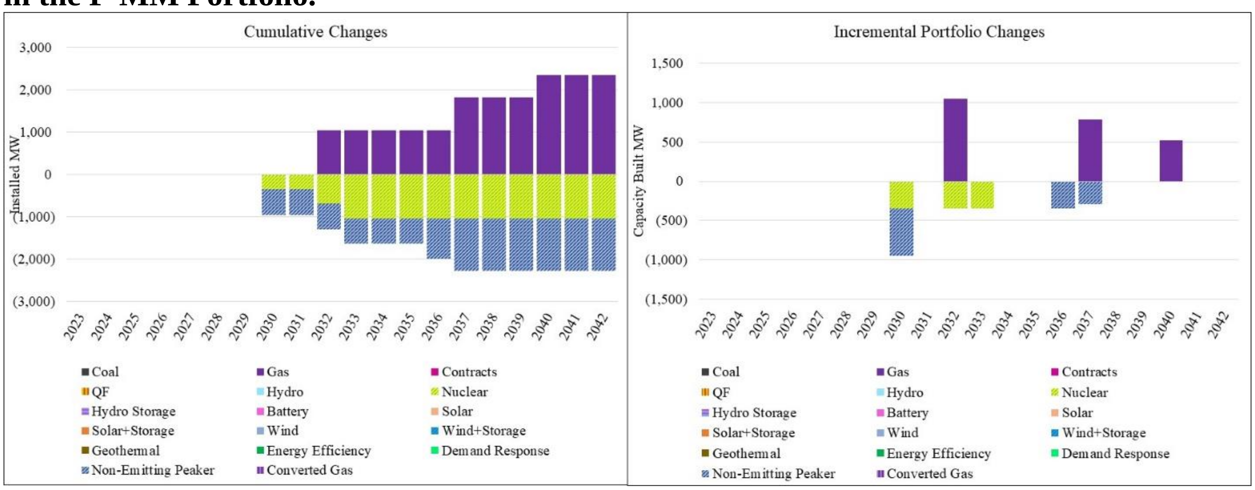
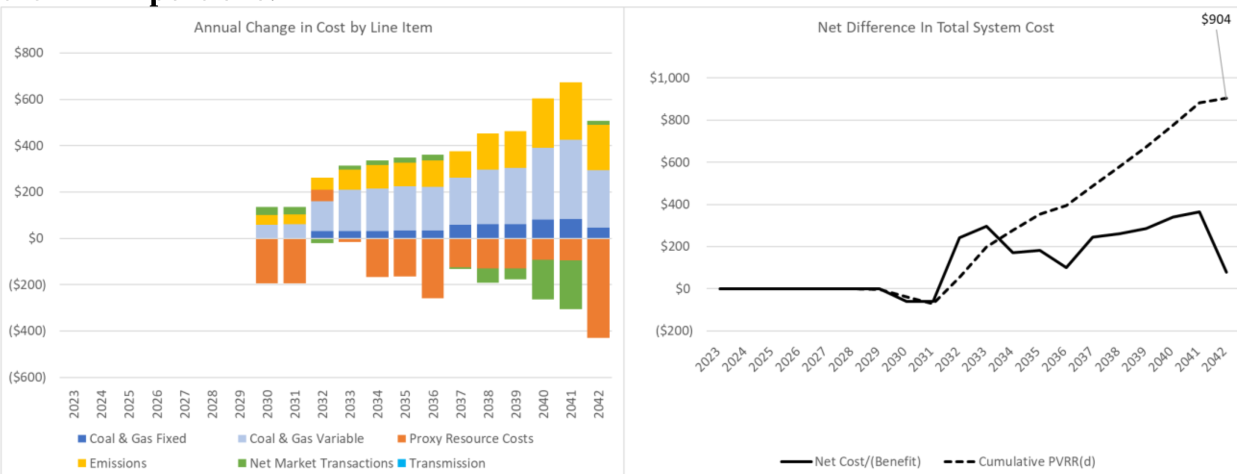


Figure 9.21 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when gas replaces all future technology in the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio which replaces future technology with gas fueled generation is $904 million higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio wich replaces future technology with gas fueled generation is $1,161 million higher cost than the P1-MM portfolio.

Lower future proxy fixed costs are the result of lower capital and fixed costs on gas fueled units. These lower costs are offset by much higher variable and fuel costs, as well as significantly higher emissions costs.

Figure 9.21 – Increase/(Decrease) in System Costs when Gas Replaces Future Technology in the P-MM portfolio.



Retire All Coal by Year-End 2029; Retire All Natural Gas by Year-End 2039 Variant (P12-RET Coal 30 NG 40)

The P12- Retire Coal by end of 2029, Retire Gas by end of 2039 Variant portfolio is a variant of the P-MM portfolio that evaluates potential costs and benefits to the system in a scenario where all coal is retired by the end of 2029 and all gas is retired by the end of 2039. When this variant is compared to the P-MM portfolio, changes in proxy resource selections and system costs driven by early retirements of all fossil fueled resources can be isolated.

Figure 9.22 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is retired no later than the end of 2029 and gas is retired no later than the end of 2039. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. For coal plants where natural gas conversion is an option, natural gas conversion is the selection made by the model. Due to the high level of coal sited surplus renewables, generators in this case are replaced towards the end of life with non-emitting peaking resources. In 2037, 1501 MW of non-emitting peaking resources are selected by the model, along with 136 MW of wind. 623 MW of additional stand alone storage was added to the east side of the system and 500 MW of stand alone storage was added to the west side in 2037 as well.

9.22 - Increase/(Decrease) in Proxy Resources when Coal is retired by the end of 2029 and gas is retired by the end of 2039 in the P-MM Portfolio

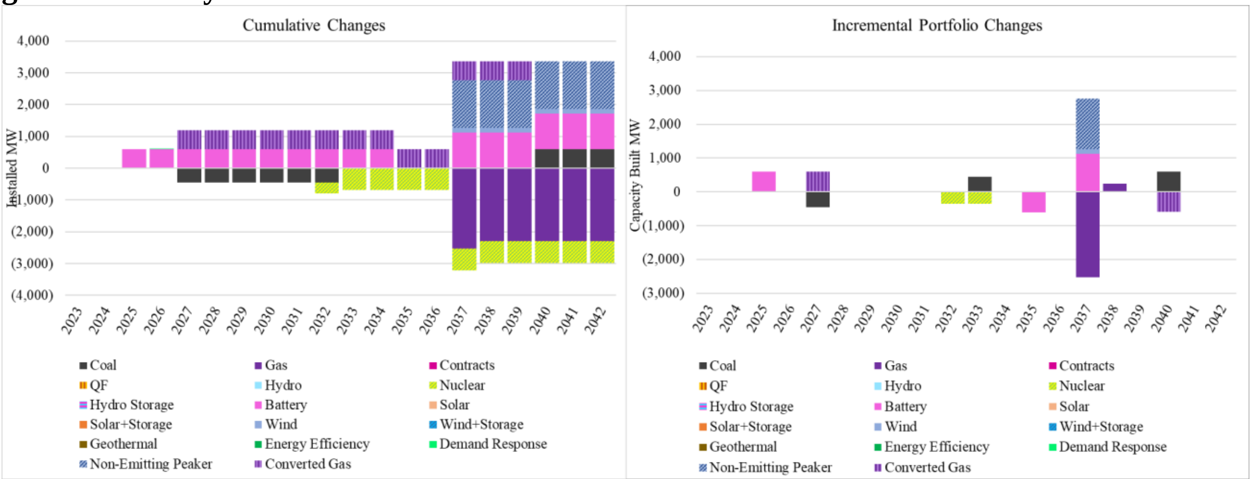
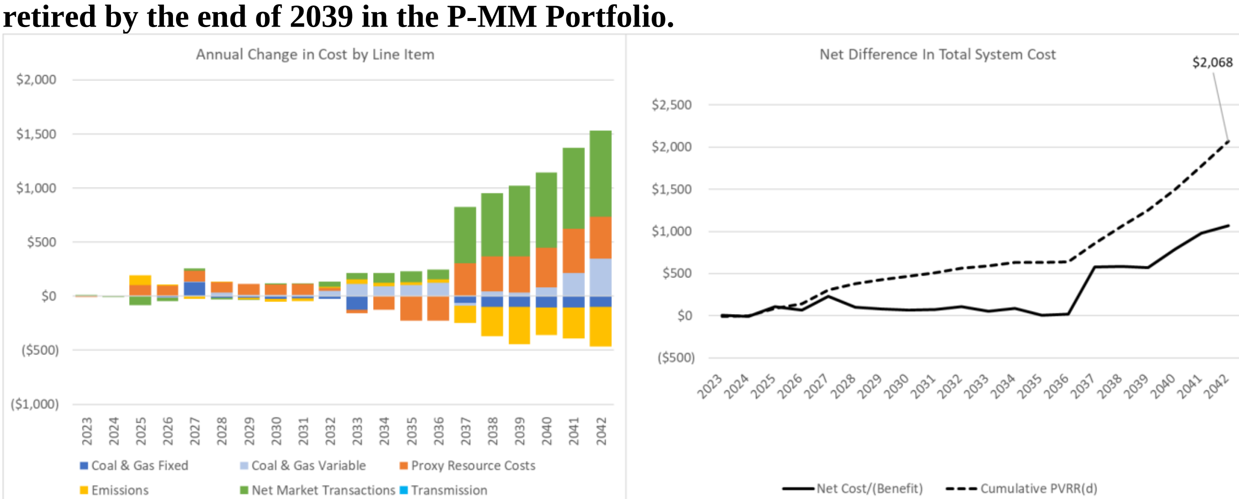


Figure 9.23 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when coal is retired by 2029 and gas is retired by 2039 gas replaces all future technology in the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the early retirement portfolio is which replaces future technology with gas fueled generation is $2.068 billion higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the early retirement portfolio is portfolio wich replaces future technology with gas fueled generation is $2.27 billion higher cost than the P-MM portfolio.

These cost changes are driven by variable cost differences. There is much higher market reliance without natural gas and coal fueled generation. Additionally, although coal and gas are retired, the need to keep firm resources on the system through gas conversion of 2 coal units leads to higher gas fuel costs.

9.23 - Increase/(Decrease) in System Costs when Coal is retired by the end of 2029 and gas is retired by the end of 2039 in the P-MM Portfolio.



All DSM Programs Variant (P13-All DSM)

The Include all DSM variant forces the model to select all demand response and energy efficiency available in addition to what is selected in the P-MM portfolio. This scenario does not change any other resource selections, but does seek to define dispatch, emissions and costs if all DSM programs are implemented. The changes to DSM selections are summarized in Figure 9.24. By the end of the study 3,128 MW of energy efficiency and 871 MW of demand response are selected.

Figure 9.24 - Increase/(Decrease) in Proxy Resources when all DSM programs are selected in P-MM Variant (P13-All DSM)

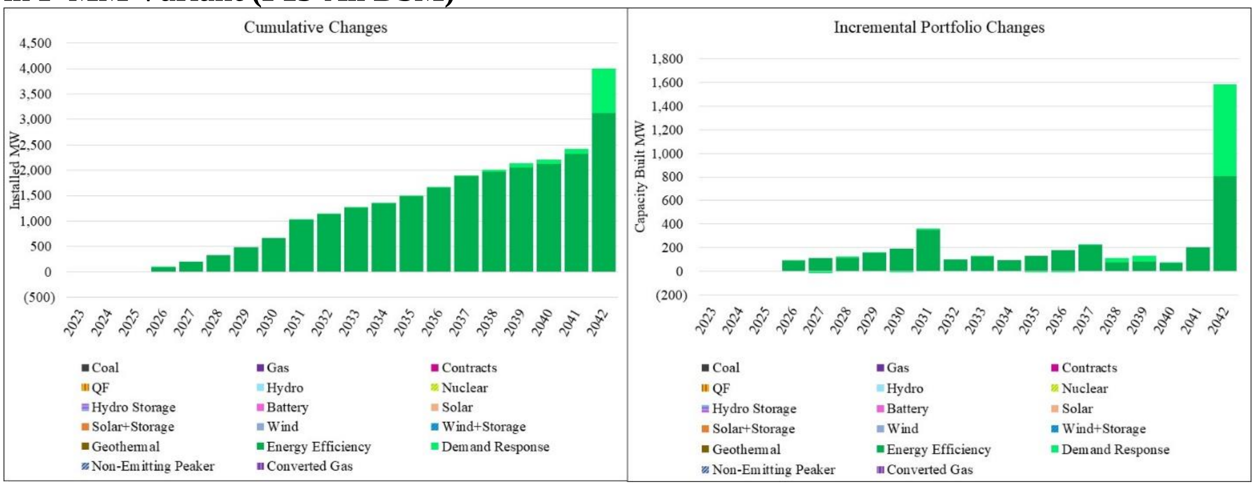
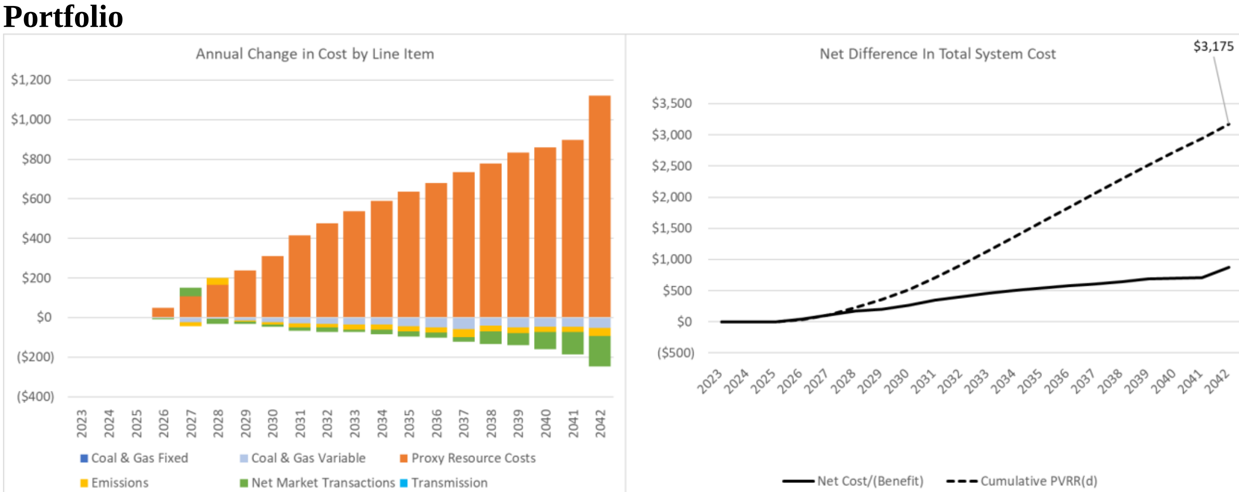


Figure 9.25 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when all DSM is selected in the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that adding all DSM is $3,175 million higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio that adds all DSM is $3,143 million higher cost than the P-MM portfolio. Coal and gas fuel cost reductions, reduced reliance on the market and lower emissions costs are offset beginning in 2027 by the much higher DSM costs.

Figure 9.25 – Increase/(Decrease) in System Costs of including all DSM in the P-MM Portfolio

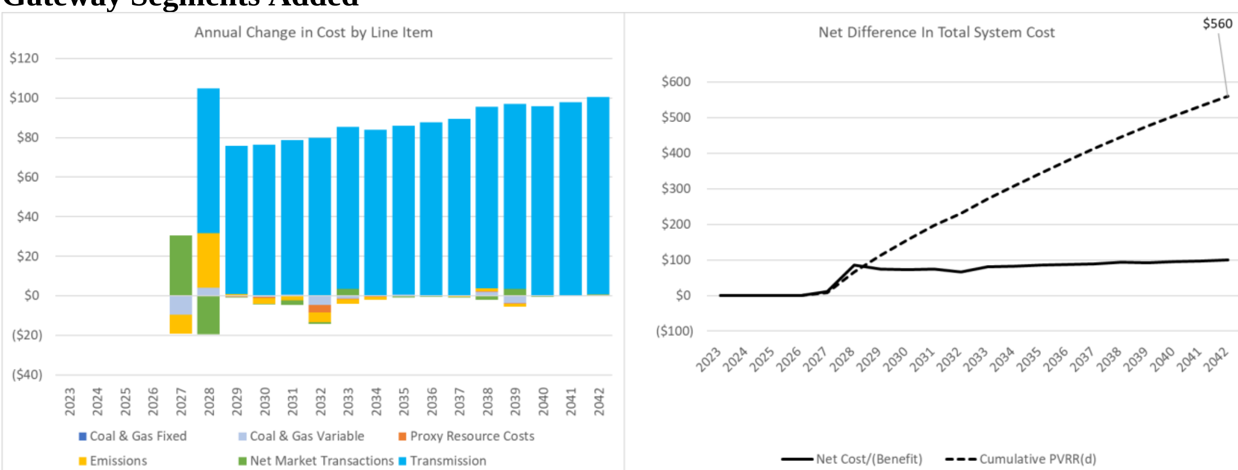


Inclusion of All Energy Gateway Transmission Options Variant (P14-All GW)

The Include All Energy Gateway Transmission Options Variants adds in Segment E, which is the only portion of the Energy Gateway Transmission project which was not selected by the model. As this specific portion of the Energy Gateway project does not enable new resource interconnection, this variant seeks to evaluate whether the increased flexibility to the transmission system provided by Segment E is a cost or benefit to the system. There is no portfolio difference to show in this scenario as resource selections are assumed not to be impacted by this addition.

Figure 9.26 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Segment E is included in the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the addition of Segment E is $560 million higher cost than the P-MM portfolio. The risk adjustments for the two portfolios ended up rounding to the same number, so on a risk-adjusted basis the All Gateway variant remains $560 million higher cost than the P-MM portfolio, with the entirety of the difference made up of increased transmission costs.

Figure 9.26 – Increase/(Decrease) in System Costs of P-MM Portfolio with All Energy Gateway Segments Added



Exclusion of Energy Gateway South Variant (P15-No GWS)

The P15-No GWS portfolio is a variant of the P1-MM portfolio that eliminates the GWS, D.1, D2.2 and D3 transmission lines as these lines are reliant on each other to be built. Because wind bids from the 2020AS RFP and future proxy resources that are located in eastern Wyoming cannot interconnect without these transmission lines, these resources are also eliminated from the P15-No GWS portfolio. When this variant is compared to the P1-MM portfolio, changes in proxy resources and system costs driven by the removal of GWS and associated transmission lines can be isolated.

Figure 9.27 shows the cumulative (at left) and incremental (at right) portfolio changes when these transmission lines are eliminated from the P1-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the transmission lines are eliminated. Without GWS and D.1, 2020AS RFP wind resources are removed from the portfolio in 2024 (shown as a reduction in 2025, the first full year these resources would be online). An additional 289 MW of wind is eliminated in 2030. In 2034, the absence of the new wind resources triggers the addition of an additional advanced nuclear plant that displaces solar co-located with storage resources. The lack of resource additions with the removal of wind resources in the portfolio without GWS and D.1 signals an increase in market reliance.

Figure 9.27 – Increase/(Decrease) in Proxy Resources when the GWS and D.1 Transmission Lines are Eliminated from the P-MM portfolio.

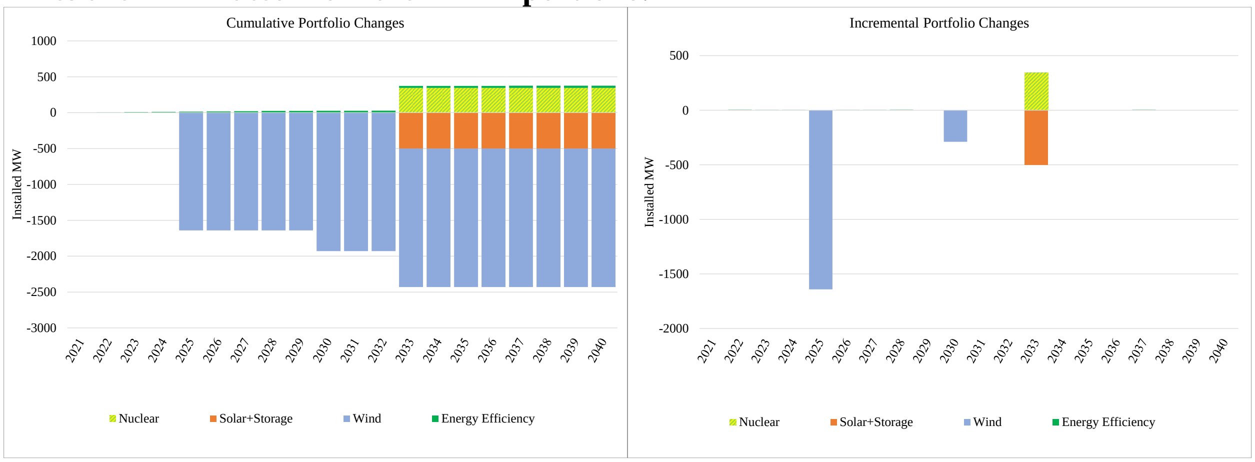
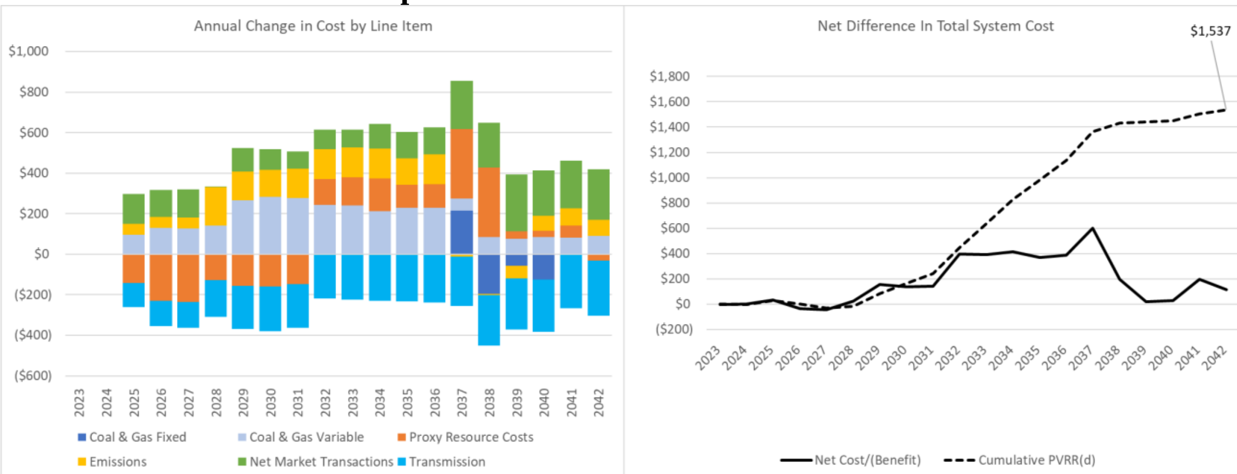


Figure 9.28 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the GWS and associated transmission lines are eliminated from the P1-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio without the GWS and D.1 transmission lines is $1,537 million higher cost than the P1-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the GWS and associated transmission lines is $1,822 million higher cost than the P1-MM portfolio. The risk-adjusted results indicate that the GWS and D.1 transmission lines add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

Lower transmission and proxy fixed costs are far outweighed by much higher emission costs and variable operating costs across the portfolio. There is a much higher reliance on markets without GWS and associated transmission lines, and the portfolio has much greater exposure to coal and gas fuel prices.

Figure 9.28 – Increase/(Decrease) in System Costs when the GWS Transmission Lines are Eliminated from the P1-MM portfolio.



Exclusion of the Selection of B2H Transmission Variant (P16-No B2H)

The P16-No B2H portfolio is a variant of the P-MM portfolio that eliminates the B2H transmission line. When this variant is compared to the P-MM portfolio, changes in proxy resources and system costs driven by the removal of the B2H transmission line can be isolated.

Figure 9.29 shows the cumulative (at left) and incremental (at right) portfolio changes when the B2H transmission line is eliminated from the P-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the transmission line is eliminated. Without B2H, 300 MW of wind and 400 MW of solar co-located with 600 MW of storage is removed from the portfolio at Borah in 2028. 725 MW of eight-hour duration battery is added to the portfolio in 2027 as a requirement in Southern Oregon in the absence of B2H, however this battery is held available to increase the reliability of deliveries to Central Oregon loads, so it is not dispatched under the normal system conditions represented in the Plexos model. The resources removed from Borah are shifted to Southern Oregon and Walla, with 600 MW of battery added to those locations in 2028, an acceleration of 400 MW of wind from 2033 into 2030, and an additional 1000 MW of solar and 600 MW of storage added in Southern Oregon in 2033. Without incremental access to PacifiCorp East resources in the absence of B2H, significantly more resources are required in Oregon.

Figure 9.29 – Increase/(Decrease) in Proxy Resources when the B2H Transmission Line is Eliminated from the P-MM portfolio.

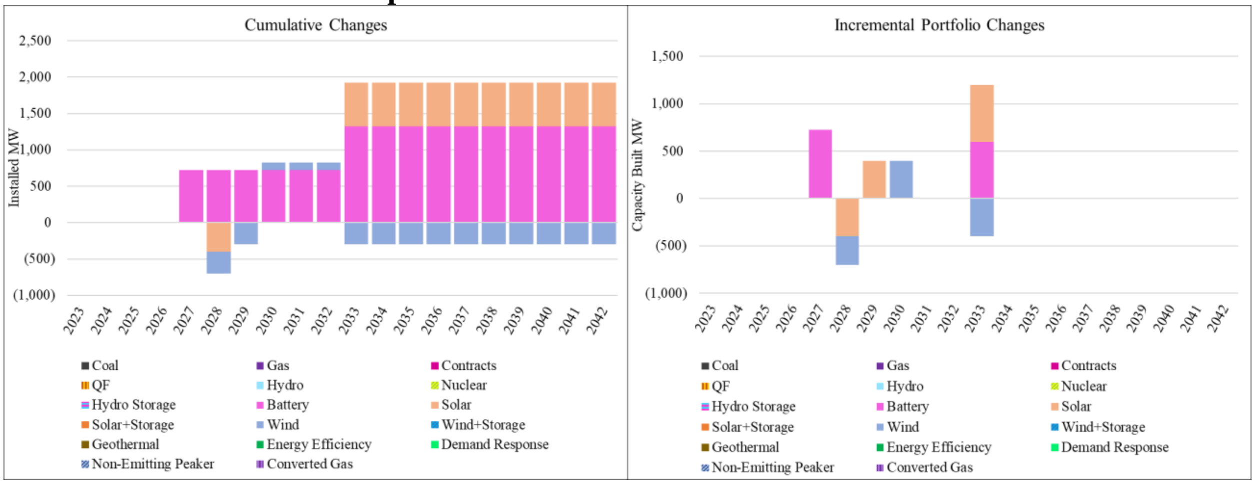
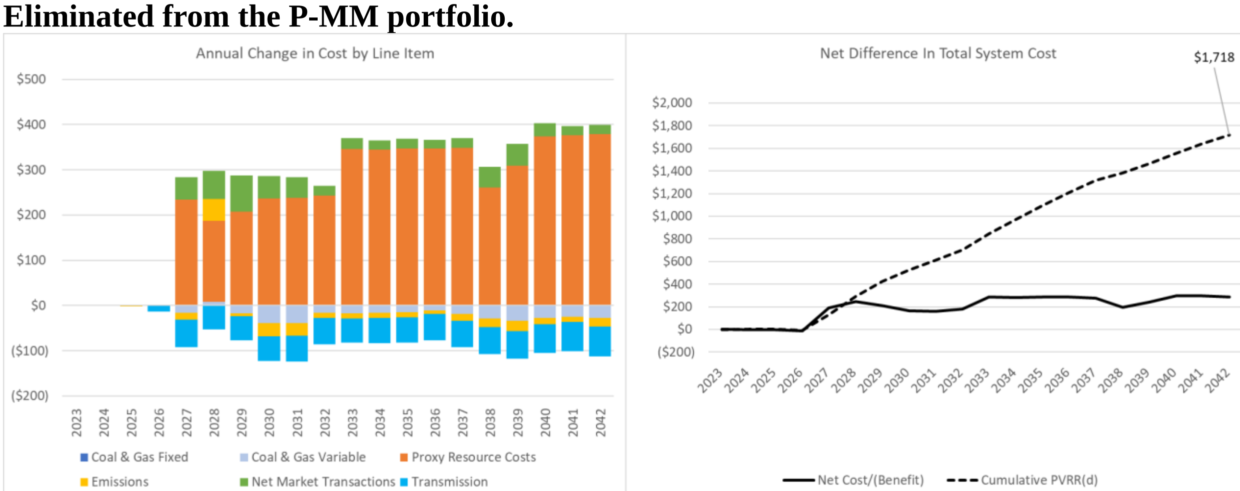


Figure 9.30 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the B2H transmission line is eliminated from the P1-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio without the B2H transmission line is $1,718 million higher cost than the P1-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without B2H is $1,716 million higher cost than the P1-MM portfolio.

Without the B2H transmission line, the cost for proxy resources is increased consistent with the changes in the resource portfolio, primarily cost of the 725 MW of incremental eight-hour battery resources if the B2H transmission line is not built. The changes in resources results in an increase in net market costs, indicating that without the B2H transmission line, the system would be more dependent on the market, despite additional resources added in southern Oregon and the Walla Walla area.

Figure 9.30 – Increase/(Decrease) in System Costs when the B2H Transmission Line is Eliminated from the P-MM portfolio.

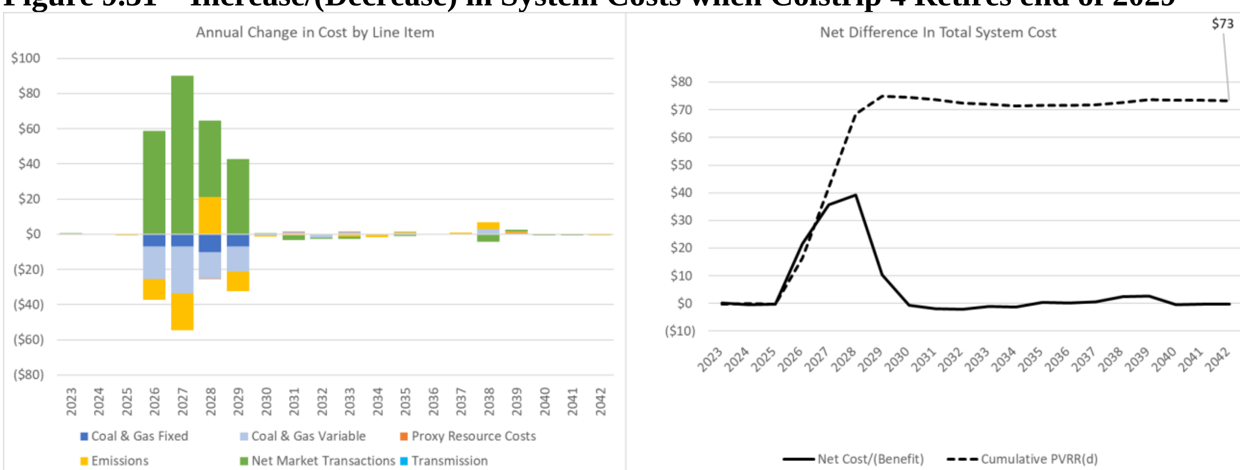


Colstrip Unit 3 and Unit 4 Retire Year-End of 2025 Variant (P17-Col3-4 RET25)

The P17-Colstrip 3 & 4 Retire in 2025 portfolio is a variant of the P-MM portfolio that exits PacifiCorp's participation in the generation of both Costrip 3 and Colstrip 4 coal plants at the end of 2025. The P-MM portfolio assumes that the company shifts it's contracted portion of Colstrip 3 to Colstrip unit 4 at the end of 2025 and continues operation through 2029. This counterfactual examines potential costs or benefits to the system of this continuation assumption. When this variant is compared to the P-MM portfolio, changes in system costs and dispatch related to this extension can be isolated.

Figure 9.31 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Colstrip 4 is retired early in the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that Colstrip 4 2025 retirement is $73 million higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, Colstrip 4 2025 retirement is $206 million higher cost than the P-MM portfolio.

Figure 9.31 – Increase/(Decrease) in System Costs when Colstrip 4 Retires end of 2029



Enable Cluster 1 Clover Transmission in Area 5/6/7 Variant (P18-Cluster East)

The Cluster East variant forces the model to incrementally select additional cluster study resources and their associated transmission within the Clover bubble. There are 3 cluster areas within the Clover bubble and this variant required that the model select all of them on top of the selections made in the preferred portfolio. This scenario does not change any other resource selections The goal of this study is to examine the impact of adding an even greater amount of renewable resources to the portfolio. The additional generator and storage resource selections in this variant are summarized in Figure 9.32. An additional 2,173 MW of co-located solar and storage are selected in 2029.

Figure 9.32 - Increase/(Decrease) in Resources With Addition of East Cluster

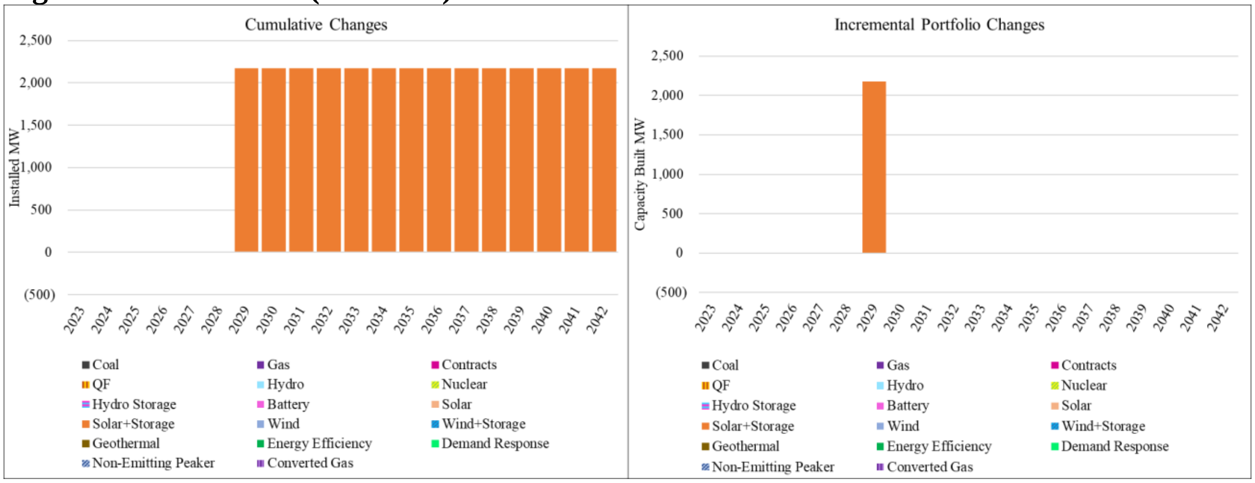
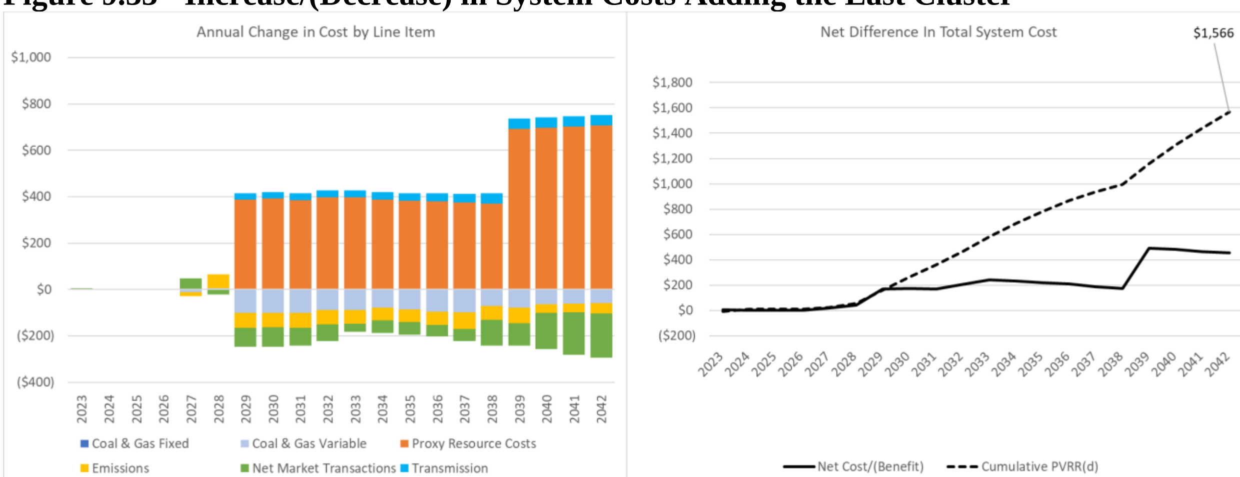


Figure 9.33 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, the East Cluster is added into the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that adding all Clover area cluster resources is $1,556 million higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio adding the East Cluster $1,947 million higher cost than the P-MM portfolio. Reduced reliance on the market and lower emissions costs are offset beginning in 2029higher DSM proxy resource and transmission costs.

Figure 9.33 - Increase/(Decrease) in System Costs Adding the East Cluster



Enable Cluster 1 Area 12 Transmission and Resources Variant (P19 Cluster West)

The Cluster West variant forces the model to incrementally select additional cluster study resources and their associated transmission within the Southern Oregon bubble. There are 3 cluster areas within the Southern Oregon bubble and this variant required that the model select all of them on top of the selections made in the preferred portfolio. This scenario does not change any other resource selections The goal of this study is to examine the impact of adding an even greater amount of renewable resources to the portfolio. The additional generator and storage resource selections in this variant are summarized in Figure 9.34. An additional 499 MW of co-located solar and storage are selected in 2028.

Figure 9.34 - Increase/(Decrease) in Resources With Addition of West Cluster

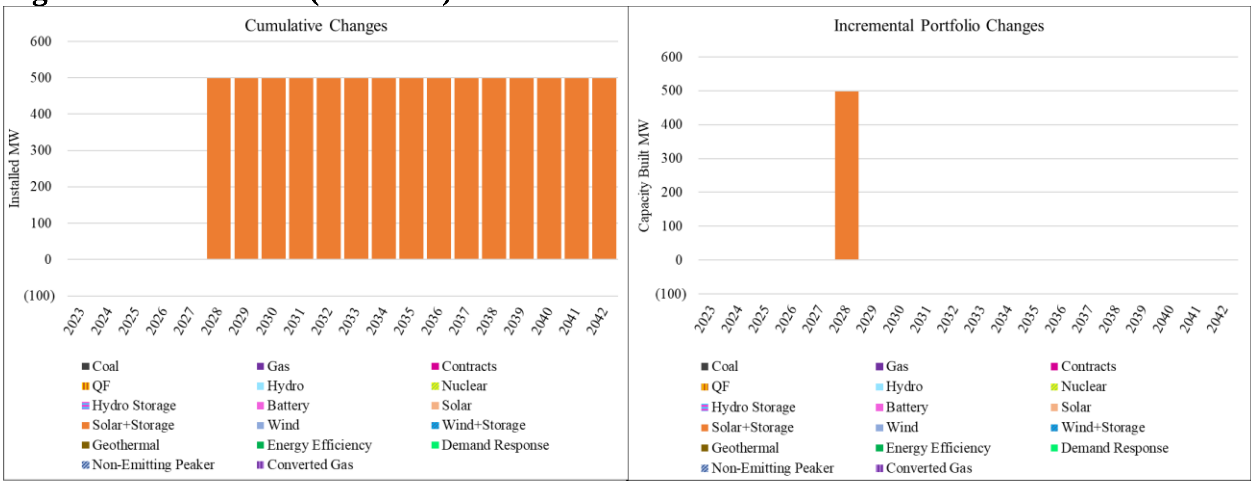
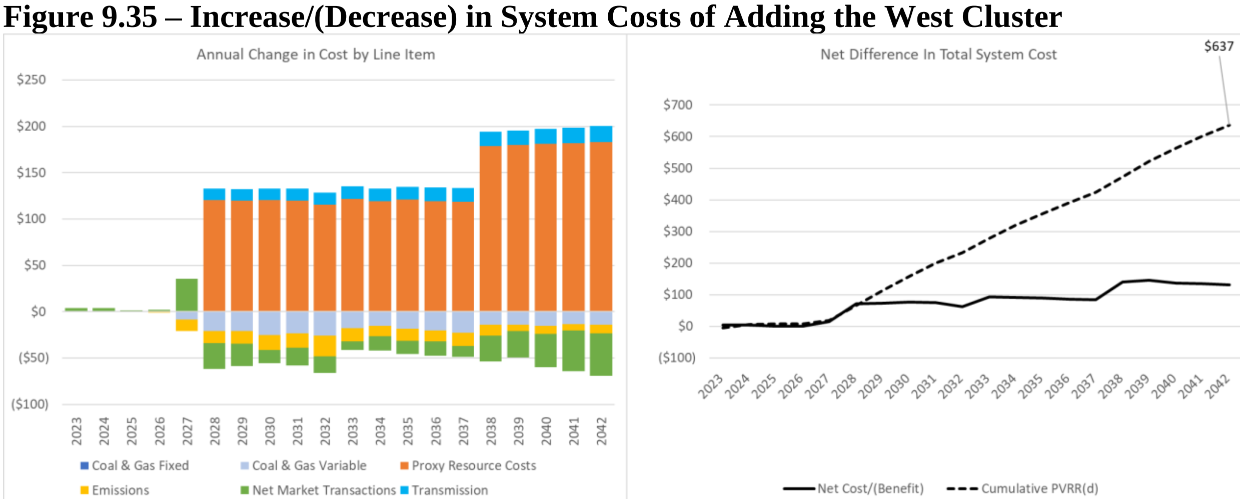


Figure 9.35 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, the West Cluster is added into the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that adding additional resources to the West Cluster is $637 million higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio operation without the West Cluster restriction is $1,018 million higher cost than the P-MM portfolio. Higher proxy resource and transmission costs were not offset by reduced variable costs of tax credited renewables.

Figure 9.35 – Increase/(Decrease) in System Costs of Adding the West Cluster



Jim Bridger Unit 3 and Unit 4 Retrofit with CCUS in 2028 Variant (P20-JB3-4 CCUS)

The P20-JB34 CCUS portfolio is a variant of the preferred portfolio that forces a CCUS retrofit on Jim Bridger Unit 3 and 4 in 2028 and where Plexos optimizes the dispatch. When this variant is compared to the preferred portfolio, changes in proxy resources and system costs driven by the CCUS retrofit can be isolated. Because CCUS was not selected as a least-cost resource option in the preferred portfolio, this variant was produced to evaluate a means to comply with Wyoming HB 200.

For modeling purposes, PacifiCorp chose to force a CCUS retrofit (amine-based carbon capture + storage) at Jim Bridger Unit 3 and 4 as it was identified in the Company's HB 200 initial application for further evalution. The Company anticipates installation of CCUS at Jim Bridger Unit 3 and 4 would meet preliminary HB 200 targets. These units have the added advantage for amine-based carbon capture technology as they currently have selective catalytic reduction (SCR) system installed. However, there could be complications with co-ownership.

Carbon capture would begin in 2028, and Jim Bridger Unit 3 and 4 would operate with CCUS out to the end of 2039 to capture tax credits. There is a net reduction of capacity due to the parasitic load associated with the carbon capture equipment.[3]

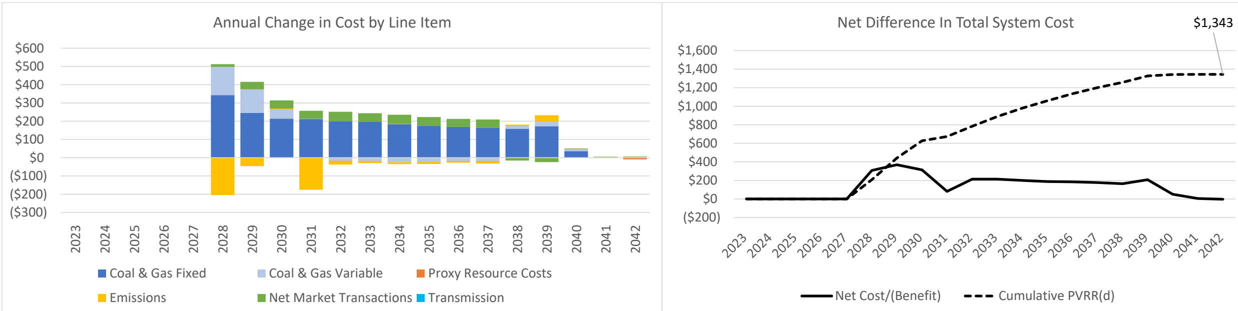
Figure 9.36 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when CCUS is installed on Jim Bridger Unit 3 and 4 in 2028. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio with CCUS installed on Jim Bridger Unit 3 and 4 project is $1,343 million higher cost than the preferred portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio with the Jim Bridger Unit 3 and 4 CCUS retrofit is $1,377 million higher cost than the preferred portfolio.

On an ST PVRR basis, capital cost assumptions for the CCUS retrofit at Jim Bridger Unit 3 and 4 would assume to foregoe the CCUS project when the higher heat rate and offtake fees dramatically reduces the unit generation making the project uneconomic.

When the CCUS retrofit is installed in 2028, the carbon capture technology increases the costs associated with Jim Bridger Unit 3 and 4. This shows up as increased fixed costs for coal and gas resources in the chart at left. This is partially offset by reduced emissions costs.

[3] Upon installation of the carbon capture equipment, Jim Bridger Unit 3 and 4's rating is 247 and 249 MW. As a coal-fired facility without carbon capture equipment, Jim Bridger Unit 3 and 4's rating is 349 and 351 MW.

Figure 9.36 – Increase/(Decrease) in System Costs when CCUS is Installed on Jim Bridger Unit 3 ands 4 in 2028



Portfolio Development Conclusions

Preferred portfolio remains the top performing portfolio among the variant portfolios. Further assessment is done relative to Washington CETA requirements, described further in a later section.

Modeling and Portfolio Selection Results

Final Preferred Portfolio Selection

P-MM entered the final evaluations as the top-performing portfolio for preferred portfolio selection.

Table 9.17 below shows the PVRR and risk-adjusted PVRR, ENS as a percentage of load, and CO_2 emissions for the 2023 IRP preferred portfolio under five price-policy scenarios.

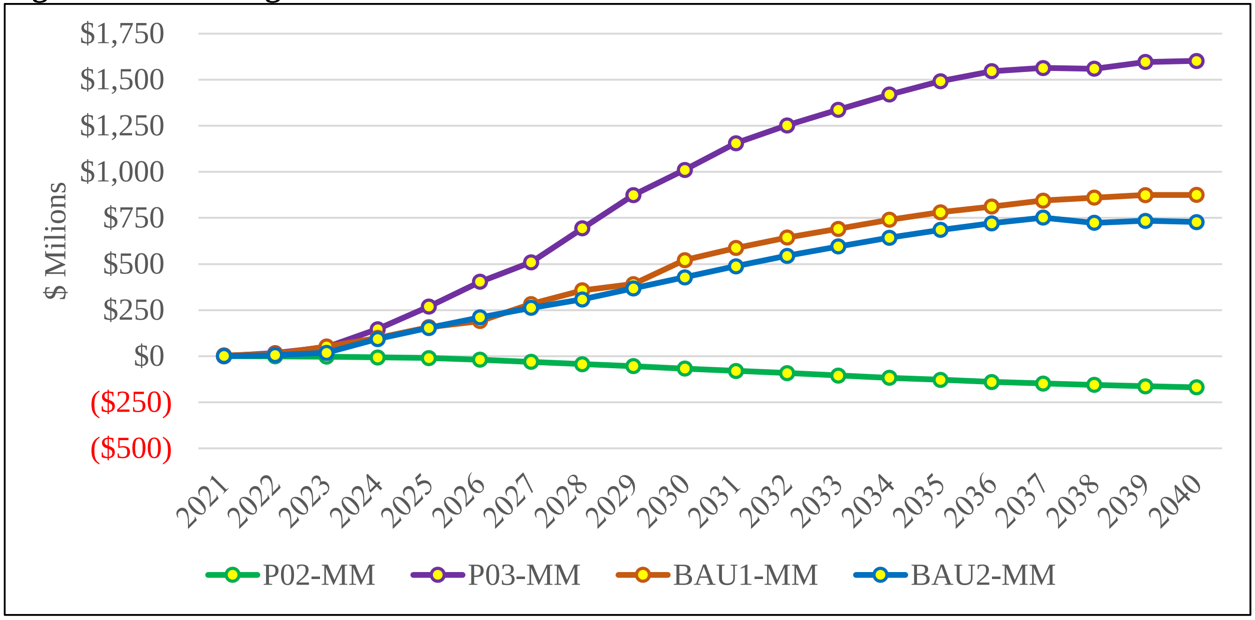
Table 9.17 - PVRR(d) of the P-MM-Portfolio Under Varying Price-Policy Scenarios

Study Name	ST PVRR ($m)	ST PVRR plus 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2023-2042 (Thousand Tons)
P-LN	$36,181	$36,155	0.00200%	306,945
P-MN	$36,257	$36,252	0.00201%	313,970
P-MM	$37,438	$37,305	0.00199%	330,442
P-HH	$45,540	$45,540	0.00197%	328,142
P-SC	$58,238	$58,192	0.00201%	332,257

Customer Rate Pressure

Figure 9.39 shows the difference in the cumulative PVRR, as an indicator of rate pressure over time, among the initial portfolios discussed earlier in this chapter relative to the 2022 IRP preferred portfolio, P-MM applying medium gas, medium CO_2 price-policy assumptions. All Portfolios P03, BAU1 and BAU2 trend higher in costs over the planning horizon relative to P-MM whereas P02 trends lower in costs notably, as it does not include Washington-situs assigned resources relative to the requirements of CETA.

Figure 9.39 – Change in the Cumulative PVRR relative to P-MM-CETA



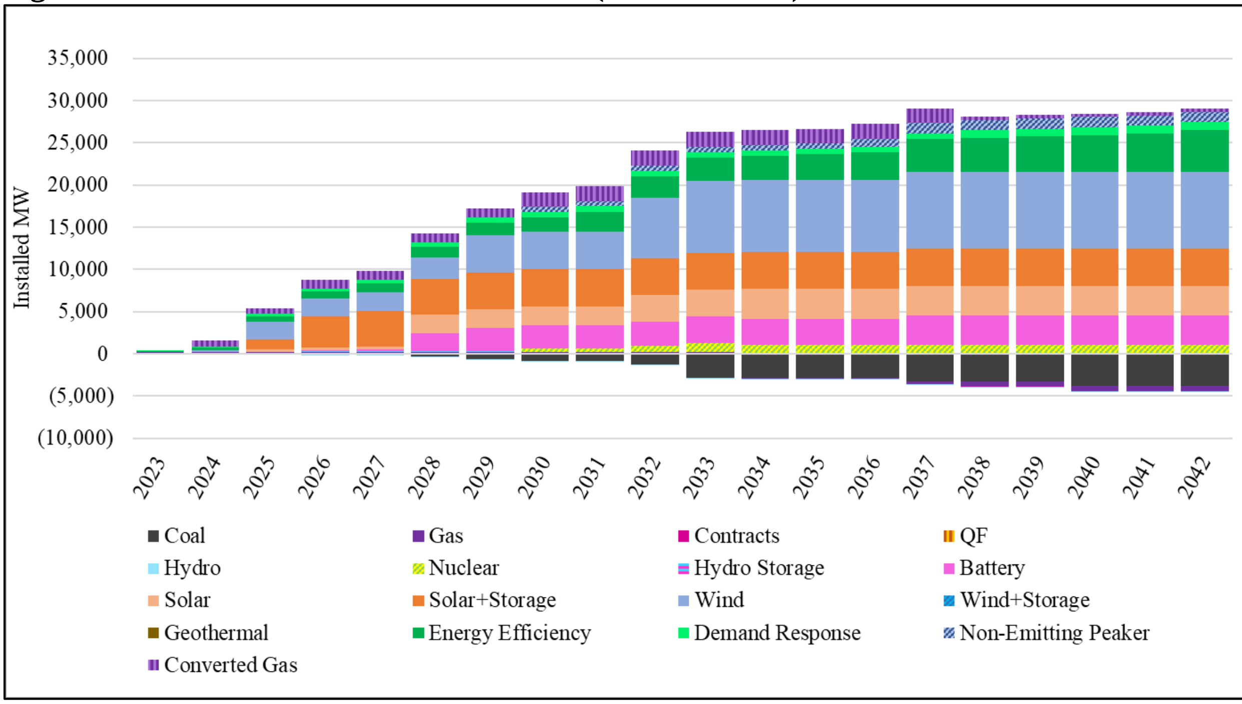
The 2023 IRP Preferred Portfolio

PacifiCorp's selection of the 2023 IRP preferred portfolio, P-MM, is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 9.40 shows that PacifiCorp's 2023 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management resources, significant storage resources, advanced nuclear, and non-emitting peaking resources.

The 2023 IRP preferred portfolio includes new resources from the 2020 All-Source Request for Proposals (RFP). These projects include 1,792 MW of wind, 495 MW of solar additions with 200 MW of battery storage capacity. These resources will come online in the 2024-to-2025 timeframe. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River I (50 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022AS RFP is currently soliciting and evaluating resources to fulfill.

The 2023 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Through 2033, the 2023 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources, and through 2037, the preferred portfolio includes1,240 MW of non-emitting peaking resources. Advancement of these two technologies will be critical to the planned transition of our coal resources in a way that will minimize impacts to our employees and our communities. Over the 20-year planning horizon, the 2023 IRP preferred portfolio includes 9,114 MW of new wind and 7,855 MW of new solar.

Figure 9.40 – 2023 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the 2023 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2023 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59-mile, high-voltage (230-kilovolt) transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.

The 2023 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway ("B2H"), which connects the Longhorn substation near the town of Boardman in Oregon to the Hemingway substation in Idaho, which will come online in 2026. By exchanging certain transmission assets with Idaho Power Company, PacifiCorp will receive additional transmission rights between Hemingway and the Populus substation in Idaho, which is closely tied to existing and future PacifiCorp transmission connecting to Utah and

Wyoming. At the Oregon end of the B2H line, additional transmission upgrades are planned to connect B2H to growing loads.

New since the 2021 IRP, the 2023 IRP preferred portfolio includes a 200 mile high-voltage 500-kilovolt transmission line from Anticline substation in central Wyoming to Populus substation in southeastern Idaho known as Energy Gateway West Sub-Segment D.3, planned to come online in 2028.

Further, the 2021 IRP preferred portfolio further included near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to serve our customers. New for the 2023 IRP, many of these transmission upgrades and the accompanying resources reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. By evaluating all newly proposed resource additions in an area at the same time, the cluster study process identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. As a result many of the transmission upgrades and resource additions in the first five years of the IRP preferred portfolio reflect cluster study requests submitted in the past two years. Table 9.18 summarizes the incremental transmission projects in the 2023 IRP preferred portfolio.

Table 9.18 – Transmission Projects Included in the 2023 IRP Preferred Portfolio 2023-2026[1,2]

Year		From	To	Export (MW)[1]	Import (MW)[1]	Inter-connect (MW)	Description
2024		Multistate Path C Improvement		0	0	100	Path C enables Utah, Idaho, Wyoming interconnection, additional transmission options
2024		Within Yakima WA Transmission Area		0	0	80	Union Gap-Midway 230 kV Line and substation - Yakima, enables additional transmission options
2025		Within Willamette Valley WA Transmission Area		0	0	9	Cluster 2 Area 22 - Willamette Valley, enables 9 MW of solar
2025		Walla Walla WA	Yakima WA	400	400	200	Walla Walla - Wine Country 230 kV line and integration, enables 200 MW of wind in 2032
2025	GWS	Wyoming East	Clover UT	1,200	1,700	2,030	Energy Gateway South, enables 1,716 MW wind, 315 MW solar and storage, and future transmission
2026		Within Borah-Populus ID Transmission Area		0	0	1,100	Cluster 2 Area 5 - Borah, enabling 1,100 MW solar and 1,100 MW storage
2026		Within BPA NITS (OR) Transmission Area		0	0	160	Cluster 2 Area 21 - BPA NITS, enables 160 MW storage
2026		Within Central Oregon Transmission Area		0	0	240	Transition Cluster Area 8 - Central Oregon, enables 200 MW solar and 200 MW storage
2026		Within Clover UT Transmission Area		0	0	331	TCA4: Q820 contingent facilities - Utah South, enables 300 MW solar and 300 MW storage
2026		Within Willamette Valley OR Transmission Area		0	0	719	Cluster 2 Area 23 - Willamette Valley, enables 474 MW solar and 474 MW storage
2026		Within Yakima WA Transmission Area		0	0	450	Cluster 1 Area 10 - Yakima, enables 450 MW solar and 707 MW storage
2026	B2H	Borah-Populus ID	Hemingway ID	600	300	600	B2H - Idaho Power Asset Transfer, enabling 300 MW wind, 400 MW solar, 600 MW storage
2026	B2H	Hemingway ID	Longhorn OR	818	0	0	B2H component
2026	B2H	Longhorn OR	McNary OR	300	0	0	B2H - Longhorn Load component
2026	B2H	Walla Walla WA	Borah ID	300	0	0	B2H - IPC PTP Eastbound component

Table 9.19 - Transmission Projects Included in the 2023 IRP Preferred Portfolio 2027-2042[1,2]

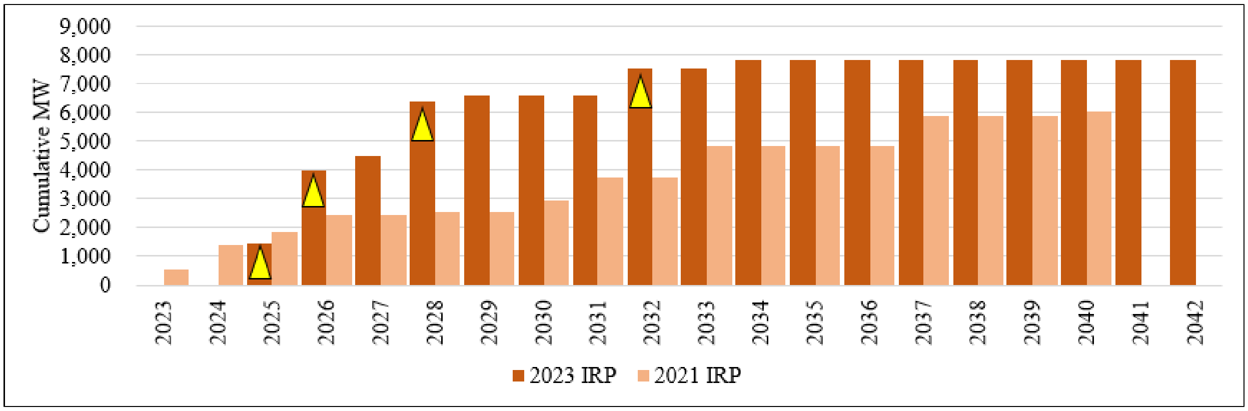
Year	From	To	Export (MW)[1]	Import (MW)[1]	Inter-connect (MW)	Description
2027	Within Walla Walla WA Transmission Area		0	0	733	Cluster 2 Area 15 - Walla Walla, enabling 100 MW wind, 483 MW solar, 628 MW storage
2028	Within Yakima WA Transmission Area		0	0	180	230 kV Union Gap-Pomona Heights, prerequisite of Union Gap-Wine Country part b
	Jim Bridger WY	Borah-Populus ID	1,621	1,621	357	Segment D3, Transition Cluster Area 1, enables 357 MW wind
2029	Within Goshen ID Transmission Area		0	0	662	Transition Cluster 5/Cluster 1 Area 3 - Goshen, enables 200 MW wind and 549 MW storage
	Wyoming East	Jim Bridger WY	950	950	1,209	D2.2/D1.2, Cluster 1 Area 1, enables 1815 MW of wind
	D3 Utah North	Borah-Populus ID	1,000	600	0	D3 supporting projects (west), enabled by D3
	D3 Wyoming East	Jim Bridger WY	728	728	298	D3 supporting projects (east), enables 298 MW wind
2030	Within Utah North Transmission Area		0	0	558	Path C improvements: mostly 138 kV, enables 300 MW wind and 606 MW non-emitting peaker
2032	Within Portland North Coast Transmission Area		0	0	130	Birdsdale 230-115 kV and Portland 115 kV reinforcement, enables 130 MW wind
	Within Yakima WA Transmission Area		0	0	100	230 kV Union Gap-Wine Country part b, enables 500 MW wind
2033	Southern Oregon	Central Oregon	389	389	935	Del Norte-Central Oregon 500kV[2], enables 1,382 MW wind and 303 MW non-emitting peaker
2037	Walla Walla WA	Willamette Valley WA	30	30	12	500 kV Walla Walla-S.Lebanon and Reinforcement[2], facilitates regional transmission

1 - TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
2 - Energy Gateway South is modeled in the 2021 IRP as a contingent option with bids in the 2020 All-Source Request for Proposals. Other transmission options prior to 2026 are not modeled as transmission requirements and costs are accounted for in the 2020 All-Source Request for Proposals transmission cluster study for all other resource bids.
* - Reclaimed transmission is committed with resources with a commercial operation date later than the date of retirement.

New Solar Resources

The 2023 IRP preferred portfolio includes 3,993 MW by the end of 2025, more than 6,200 MW by the end of 2027, and more than 7,800 MW of new solar is online by the end of 2031, as shown in Figure 9.41.

Figure 9.41 – 2023 IRP Preferred Portfolio New Solar Capacity*

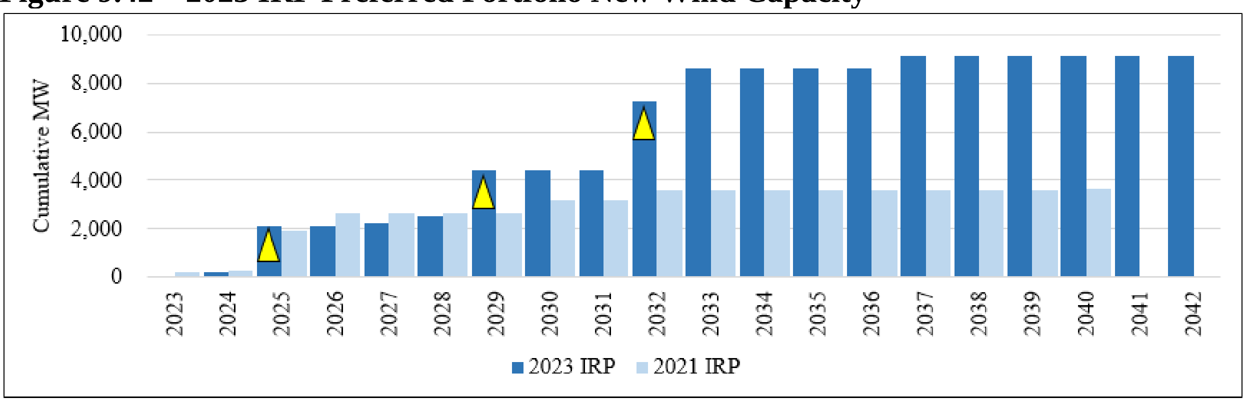


* 2023 IRP solar capacity shown in the figure includes solar resources coming via the 2020 All-Source Request for Proposals by the end of 2024. Resources are shown in the first full year of operation (the year after the year-online dates).

New Wind Resources

As shown in Figure 9.42, by year-end 2024, PacifiCorp's 2023 IRP preferred portfolio includes 2,131 MW of new wind generation resulting from the 2020 AS RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). By year-end 2028, the 2023 IRP preferred portfolio includes an additional 2,300 MW of new wind, and more than 7,200 MW of cumulative new wind by the end of 2031.

Figure 9.42 – 2023 IRP Preferred Portfolio New Wind Capacity*

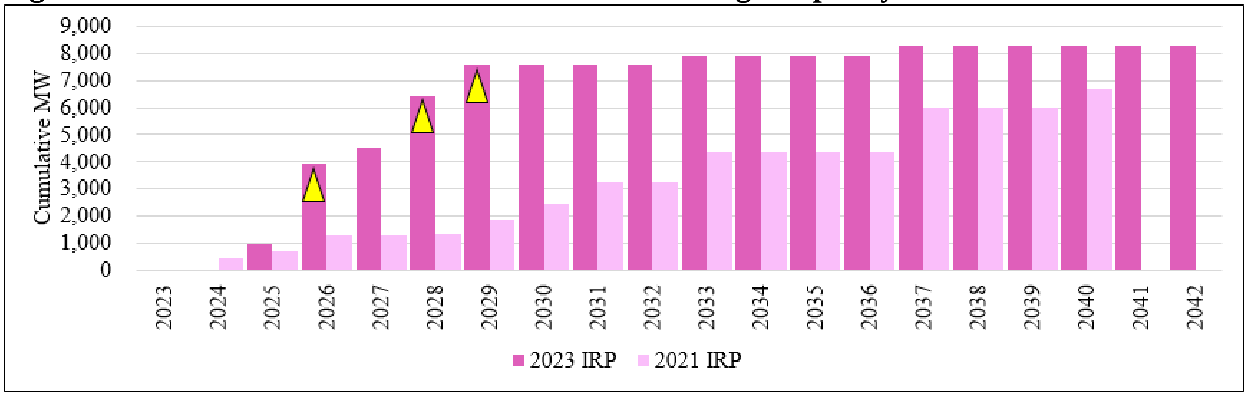


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates).

New Storage Resources

New storage resources in the 2023 IRP preferred portfolio are summarized in Figure 9.43. The 2023 IRP preferred portfolio presents a quickly escalating curve for storage selections in years 2023 through 2029, and includes over 3,900 MW by the end of 2025 – the majority of which is expected to be collocated with renewable resources by proxy selection or is paired with solar resources resulting from the 2020 All-Source RFP. By year-end 2028, the 2023 IRP includes nearly 7,600 MW of storage, comprised of 7,560 MW of proxy lithium ion battery storage and 35 MW of pumped hydro. 150 MW of long-duration storage appears by year-end 2032 and another 200 MW by the end of 2036.

Figure 9.43 – 2023 IRP Preferred Portfolio New Storage Capacity*

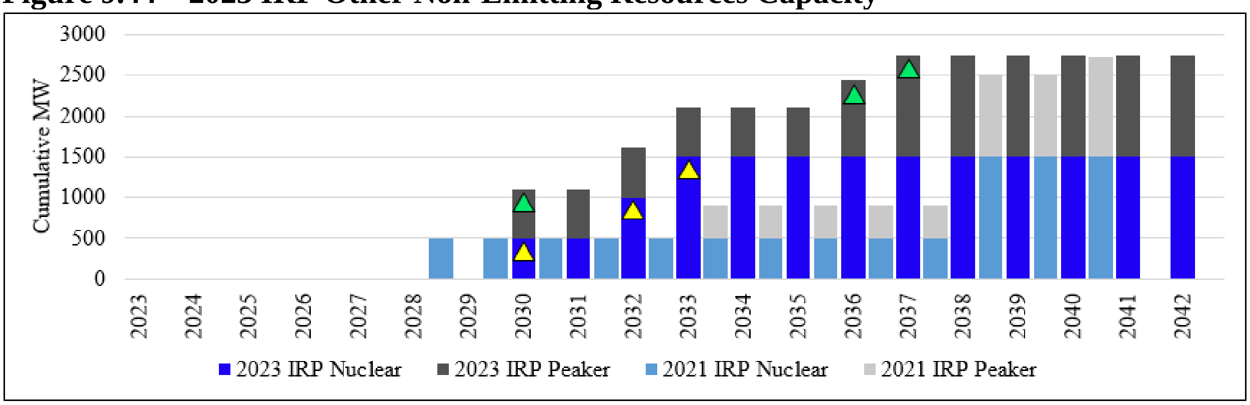


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Other Non-Emitting Resources

The 2023 IRP includes new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. As shown in 9.44, the 500 MW advanced nuclear Natrium™ demonstration project is scheduled to come online by summer 2030. By year-end 2032, the 2023 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources. The 2023 IRP also includes 606 MW of non-emitting peaking resources by year-end 2029, increasing to 1,240 MW by the end of 2036. The advancement of these new technologies are critical to the planned transition of PacifiCorp's coal fleet.

Figure 9.44 – 2023 IRP Other Non-Emitting Resources Capacity*

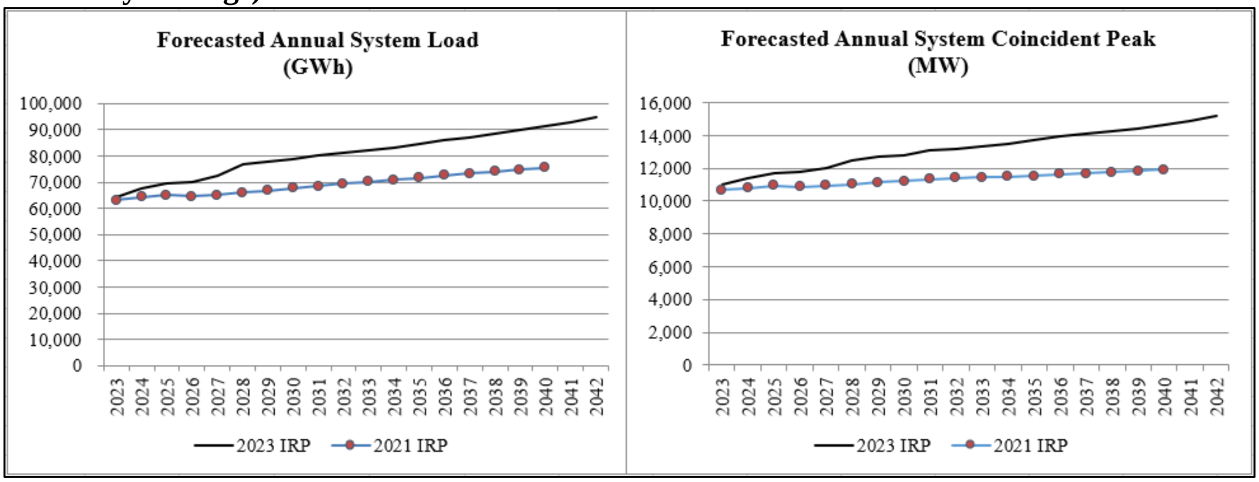


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 9.45 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2021 IRP. On average, forecasted system load is up 14.9 percent and forecasted coincident system peak is up 14.9 percent when compared to the 2021 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.07 percent for load and 1.70 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from new large customers driving up the commercial forecast and an increased residential forecast.

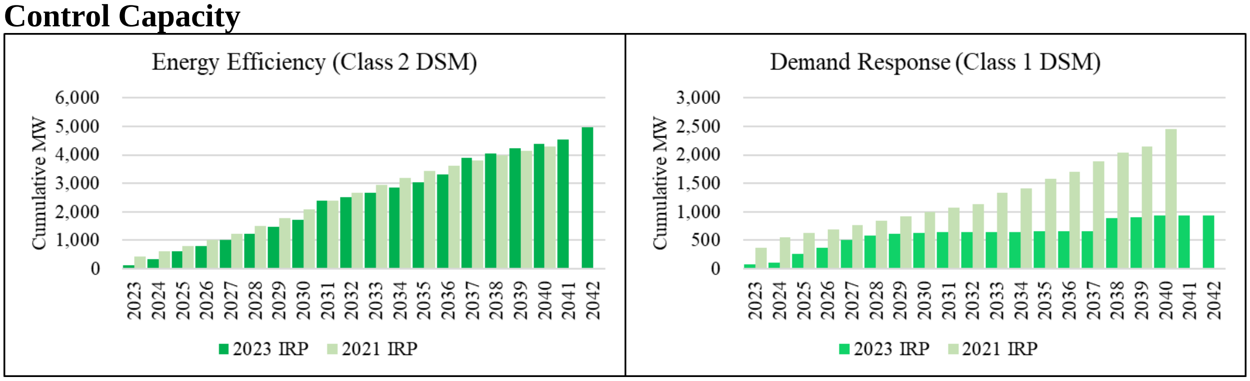
Figure 9.45 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 9.46 compares total energy efficiency capacity savings in the 2023 IRP preferred portfolio relative to the 2021 IRP preferred portfolio and includes 4,953 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 9.46 compares cumulative demand response program capacity in the 2023 IRP preferred portfolio relative to the 2021 IRP preferred portfolio and does not include capacity from existing programs. The 2023 IRP has a cumulative capacity of demand response programs reaching 929 MW by 2042 which represents a 264% decrease relative to the 2021 IRP. This decrease is the result of improved accounting for demand response resources and their potential overlap with one another. In the 2021 IRP, resources from the 2021 DR RFP were modeled concurrently with CPA resources to evaluate all possible resources. The result was an upper theorical maximum of resources that did not account for overlap in end-uses and programs. .

Figure 9.46 – 2021 and 2923 IRP Preferred Portfolio Energy Efficiency and Direct Load Control Capacity



Wholesale Power Market Prices and Purchases

Figure 9.47 shows that the 2023 IRP's base case forecast for natural gas prices has increased along with an increase in wholesale power prices for most years relative to those in the 2021 IRP. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The higher power prices observed in the 2023 IRP are primarily driven by the assumption of higher natural gas prices than what was assumed in the 2021 IRP. Wholesale power prices are higher in 2023 to 2030 due to weather conditions, higher inflation impacting new resource costs, and market volatility until the market settles. Moreover, the 2023 IRP assumed higher natural gas prices than the 2021 IRP due to impacts by world events notably including the war in Ukraine. Henry Hub in particular, is impacted by higher natural gas demand increasing liquefied natural gas exports. While not shown in the figure below, the 2023 IRP also evaluated low and high price scenarios when assessing the cost and risk of different resource portfolios.

Figure 9.47 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

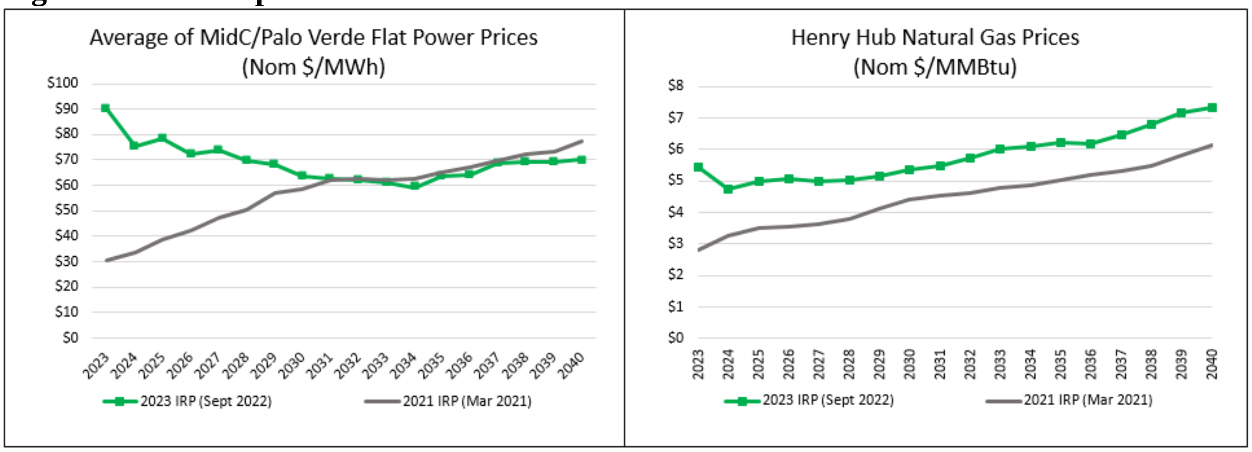
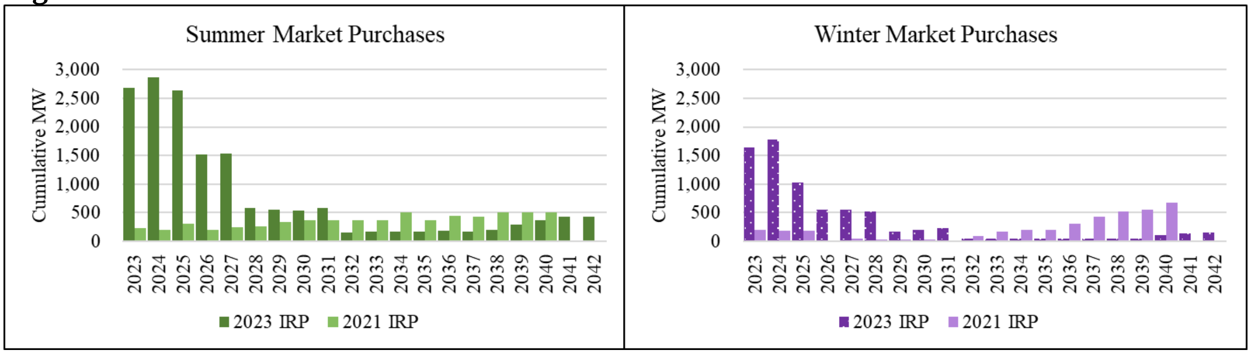


Figure 9.48 below, shows an overall increase in reliance on wholesale power market firm purchases in the 2023 IRP preferred portfolio relative to the wholesale power market purchases included in the 2021 IRP preferred portfolio. In years 2023 through 2027, the magnitude of this increase is exaggerated due to the accounting of purchases to meet near-term load obligations in the 2021 IRP, where additional purchases could have been assumed to meet deficiencies. While wholesale power market purchases are higher in 2028 through 2031 compared to the 2021 IRP, purchases are relatively less through the remaining ten years of the planning period, driven largely by the influx of cost-effective renewable energy and investments in new technology that support the planned transition for PacifiCorp's coal fleet. PacifiCorp is actively participating in regional efforts to develop day-ahead markets and a resource adequacy program that will help unlock regional diversity and facilitate market transactions over the long term.

Figure 9.48 – 2021 IRP Preferred Portfolio Market Purchases



*Note: In the 2021 IRP, higher near-term market purchases were represented by system shortfalls that were assumed to be avoided through market purchases disallowed in the model. In the 2023 IRP this methodology was enhanced to represent the coverage of these shortfalls as market purchases, declining steadily over the next several years as new resource additions, and particularly battery storage, come online.

Coal and Gas Retirements/Gas Conversions

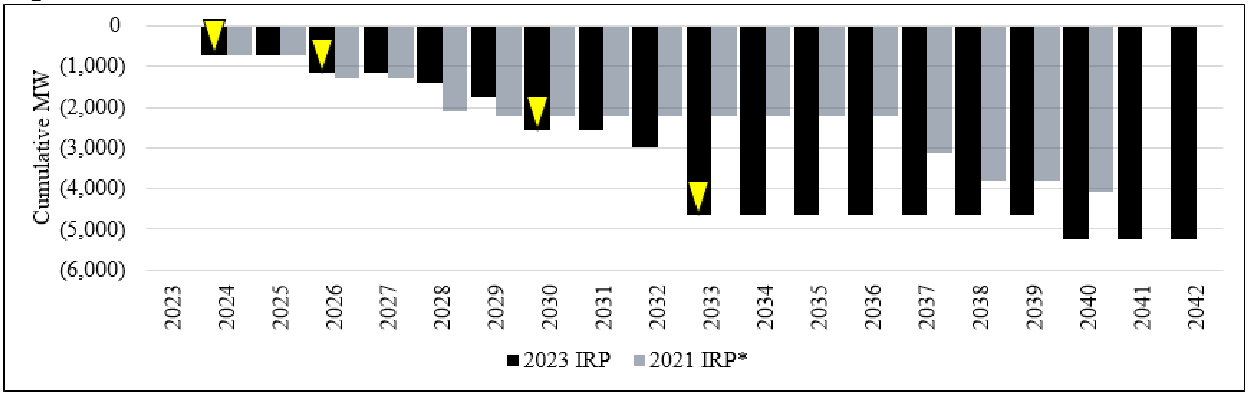
Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement or gas conversion of 13 units by 2030 and 20 units by year-end 2032. The final two coal units retire by 2039, or three years ahead of the end of the planning period, with the path to decarbonization supported by new non-emitting technologies. As shown in Figure 9.49, coal unit retirements/gas peaker conversions in the 2023 IRP preferred portfolio will reduce coal-fueled generation capacity by 1,153 MW by the end of 2025, and over 2,999 MW by 2032.

Coal unit exits, retirements, and gas conversions scheduled under the preferred portfolio include:

- 2023 = Jim Bridger Units 1-2, converted to natural gas in 2024 (same as in the 2021 IRP)
- 2025 = Craig Unit 1 retirement (same as in the 2021 IRP)
- 2025 = Colstrip Unit 3 exit (same as in the 2021 IRP)
- 2026 = Naughton Units 1-2, converted to natural gas in 2026, operates through 2036 (retired 2025 in the 2021 IRP)
- 2027 = Dave Johnston Units 3 retirement (same as in the 2021 IRP)
- 2027 = Hayden Unit 2 retirement (same as in the 2021 IRP)
- 2028 = Dave Johnston Units 1-2 retirement (retired 2027 in the 2021 IRP)
- 2028 = Craig Unit 2 retirement (same as in the 2021 IRP)
- 2028 = Hayden Unit 1 retirement (same as in the 2021 IRP)
- 2029 = Colstrip Unit 4 exit, Colstrip Unit 3 share is consolidated into Colstrip Unit 4 in 2025 (retired 2025 in the 2021 IRP)
- 2030 = Jim Bridger Units 3-4, converted to natural gas in 2030, operates through 2037 (retired 2037 without conversion in 2021 IRP)

- 2031 = Hunter Unit 1 retirement, SNCR installed 2026 (outside of 2021 IRP planning horizon, retiring 2042)
- 2032 = Hunter Units 2-3 retirement, SNCR installed 2026 (outside of 2021 IRP planning horizon, retiring 2042)
- 2032 = Huntington Units 1-2 retirement, SNCR installed 2026 (retired 2036 in 2021 IRP)
- 2039 = Dave Johnston Unit 4 retirement (retired 2027 in 2021 IRP)
- 2039 = Wyodak retirement, SNCR installed 2026 (retired 2039 without SNCR in 2021 IRP)

Figure 9.49 – 2021 IRP Preferred Portfolio Coal Exits, Retirements, and Gas Conversions*



* Note: Coal exits and retirements are assumed to occur by the end of the year before the year shown in the graph. The graph shows the year in which the capacity will not be available for meeting summer peak load. All figures represent PacifiCorp's ownership share of jointly owned facilities.

In addition to the coal unit exits, retirements, and gas conversions outlined above, the preferred portfolio reflects 2,660 MW natural gas retirements through 2042. This includes Gadsby at the end of 2032, Naughton Units 1, 2, and 3 at the end of 2036, Hermiston at the end of 2036, and Jim Bridger Units 1, 2, 3, and 4 at the end of 2037.

Carbon Dioxide Equivalent Emissions

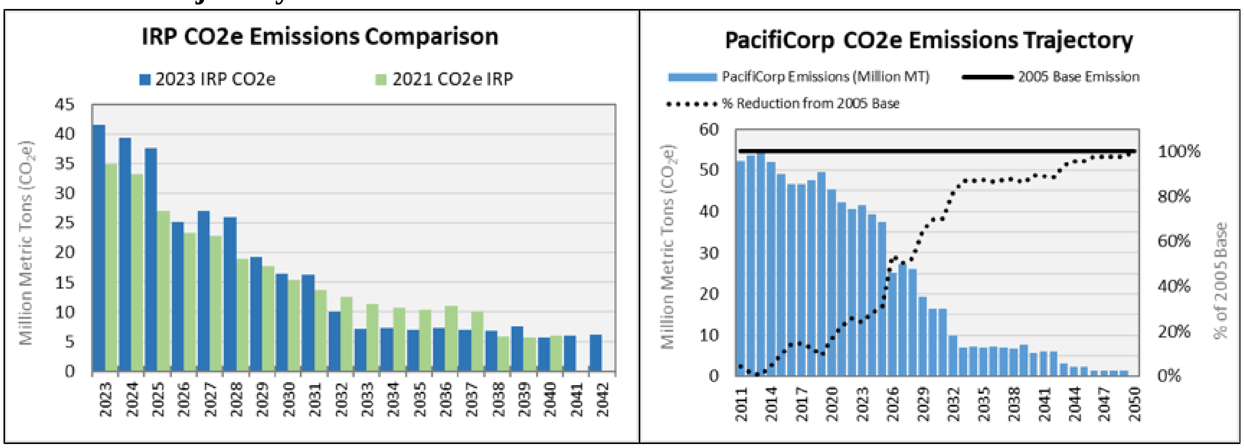
The 2023 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide and other carbon dioxide equivalent emissions resulting in a total (CO_2e) emissions. PacifiCorp's emissions have been declining and continue to decline related to several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new non-emitting resources, storage, transmission, Regional Haze compliance that capitalizes on flexibility, and the Ozone Transport Rule.

The chart on the left in Figure 9.50 compares projected annual CO_2e emissions between the 2023 IRP and 2021 IRP preferred portfolios. In this graph, emissions are assigned to market purchases. In the current 2023 IRP emissions are higher than projected in the 2021 IRP until 2032, this is a result of higher load forecast in the 2023 IRP. In addition, the 2023 IPR contains several coal plants converting to gas, but with higher dispatch of gas contributing to the uptick in emissions. By 2032, average annual CO_2e emissions are down 21 percent relative to the 2021 IRP preferred portfolio.

By 2040 emissions are comparable to the 2021 IRP while generation has increased by 31% showing that the overall emissions rate is lower under 2023 IRP portfolio. By the end of the planning horizon, system CO_2e emissions are projected to fall from 41.5 million metric tons in 2023 to 6.2 million tons in 2042—a reduction of 85 percent.

The chart on the right in Figure 9.50 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, of 54.6 million metric tons, system CO_2 equivalent emissions are down 31 percent in 2025, 70 percent in 2030, 87 percent in 2035, 89 percent in 2040, 96 percent in 2045, and 100 percent in 2050.

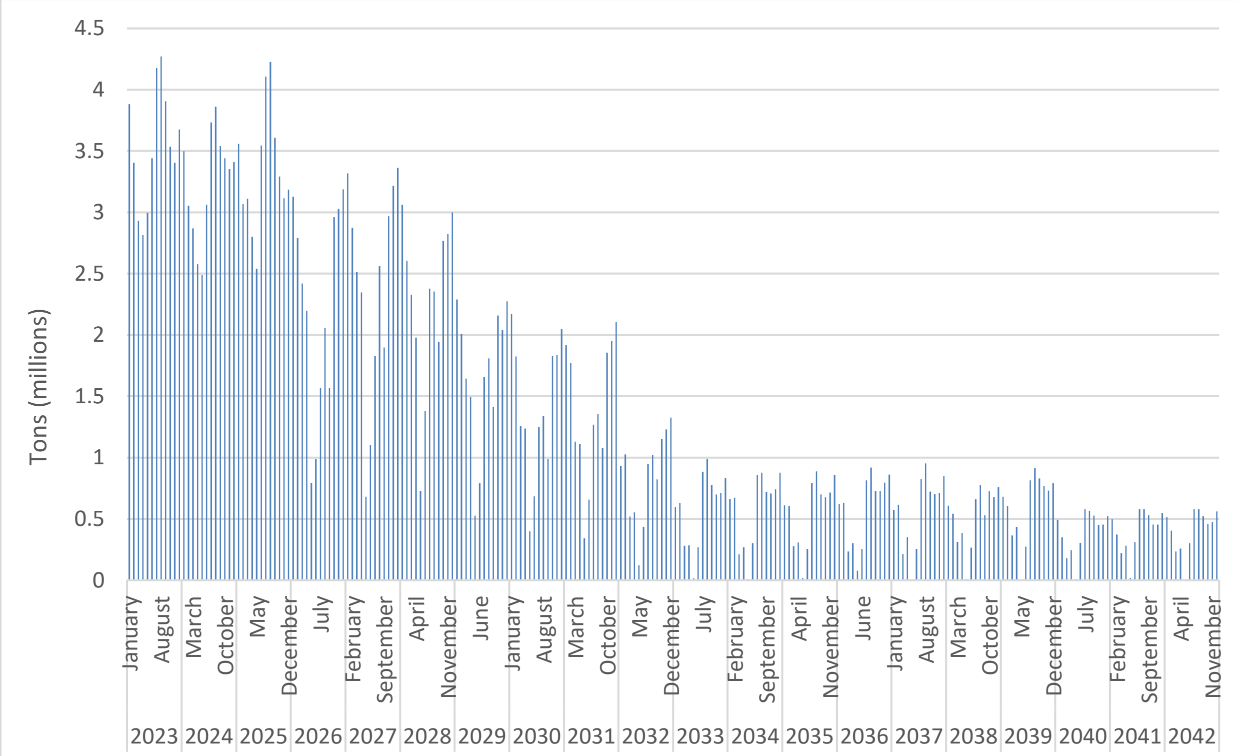
Figure 9.50 – 2021 IRP Preferred Portfolio CO2 Emissions and PacifiCorp CO2 Equivalent Emissions Trajectory*



*Note: PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2022 from owned facilities, specified sources and unspecified sources. From 2023 through the end of the twenty-year planning period in 2042, emissions reflect those from the 2023 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2042, emissions reflect the rolling average emissions of each resource from the 2023 IRP preferred portfolio through the life of the resource or the end of the contract. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be discussed in more detail in its Clean Energy Plan.

Monthly CO_2 emissions are available for the preferred portfolio as shown in
47 below.

Figure 9.51 – Monthly CO2 emissions per year for the preferred portfolio



Renewable Portfolio Standards

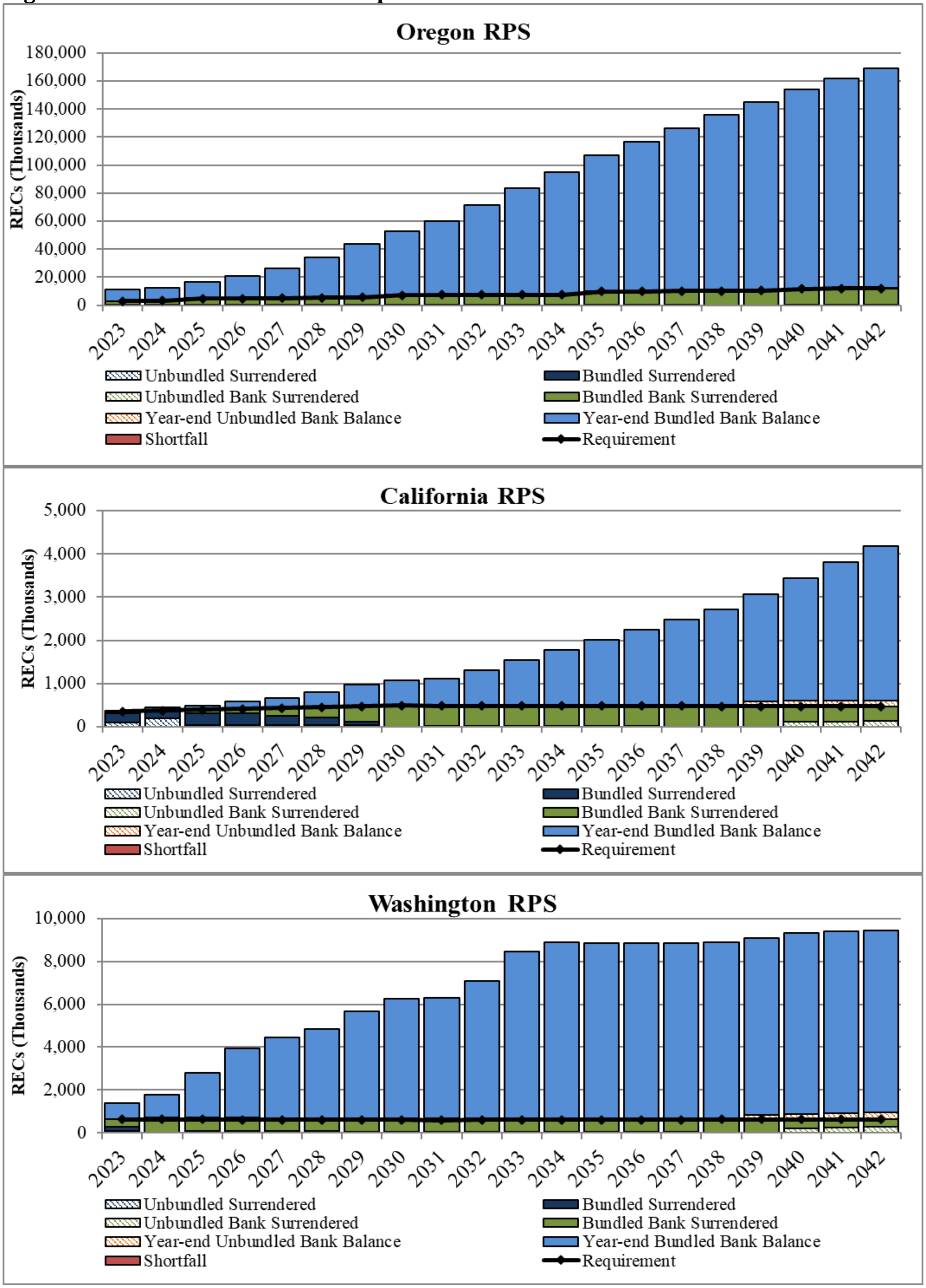
Figure 9.52 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2042 with the addition of new renewable resources. Washington RPS compliance is also achieved through 2042 with the addition of new renewable resources. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington receives a system share of renewable resources across the PacifiCorp's system.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as REC purchases throughout the 2023 IRP study period. The ramping RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in the near term. New renewable resources in the 2023 IRP preferred portfolio mitigate that shortfall, but the company is seeking to purchase approximately 200,000 RECs the near term.

While not shown in Fiure 9.52, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources and transmission in the 2023 IRP preferred portfolio.

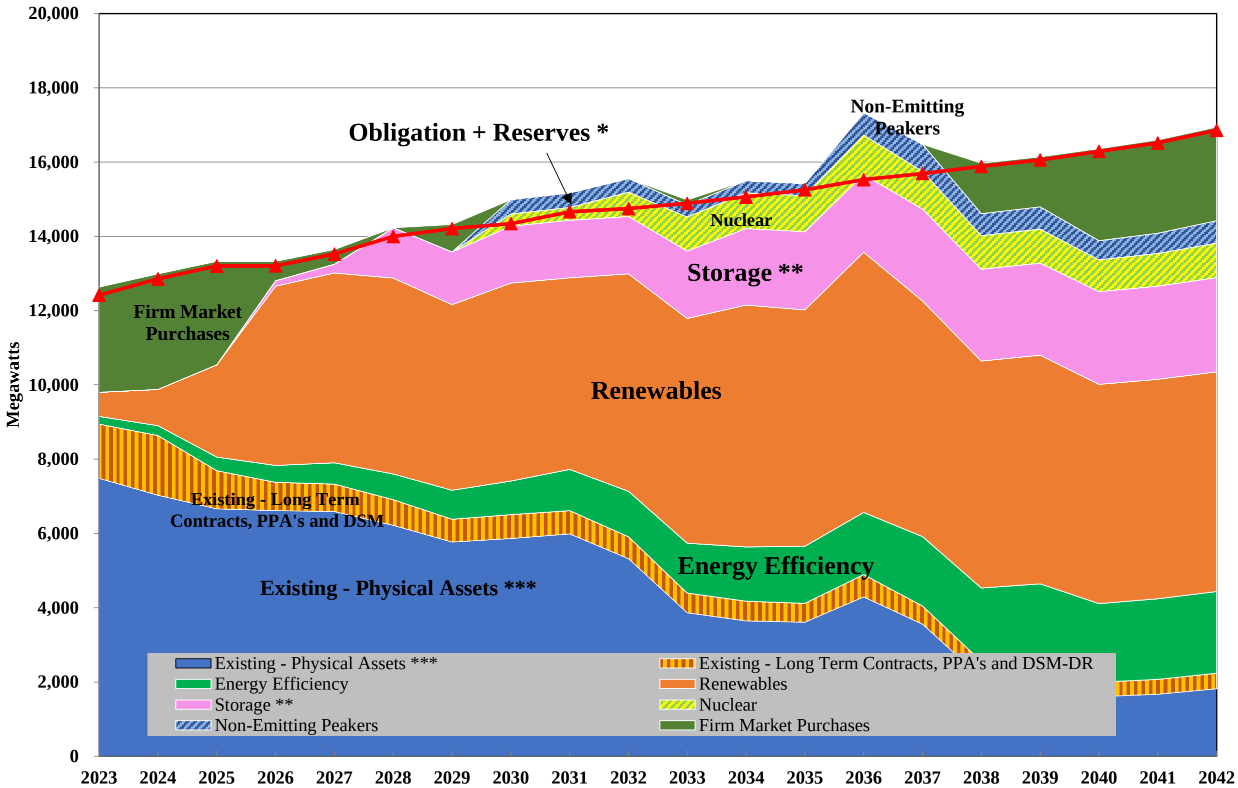
Figure 9.52 – Annual State RPS Compliance Forecast



Capacity and Energy

Figure 9.53 displays how preferred portfolio resources meet PacifiCorp's capacity needs over time. Through 2042, PacifiCorp meets its capacity needs, including a 13% planning reserve margin, through incremental acquisition of wind and solar resources and hybrid renewables (with storage) enabled by investment in transmission infrastructure, nuclear resources, strand alone storage resources, new DSM, non-emitting peaker resources, and wholesale power market purchases.

Figure 9.53 – Meeting PacifiCorp's Capacity Needs with Preferred Portfolio Resources



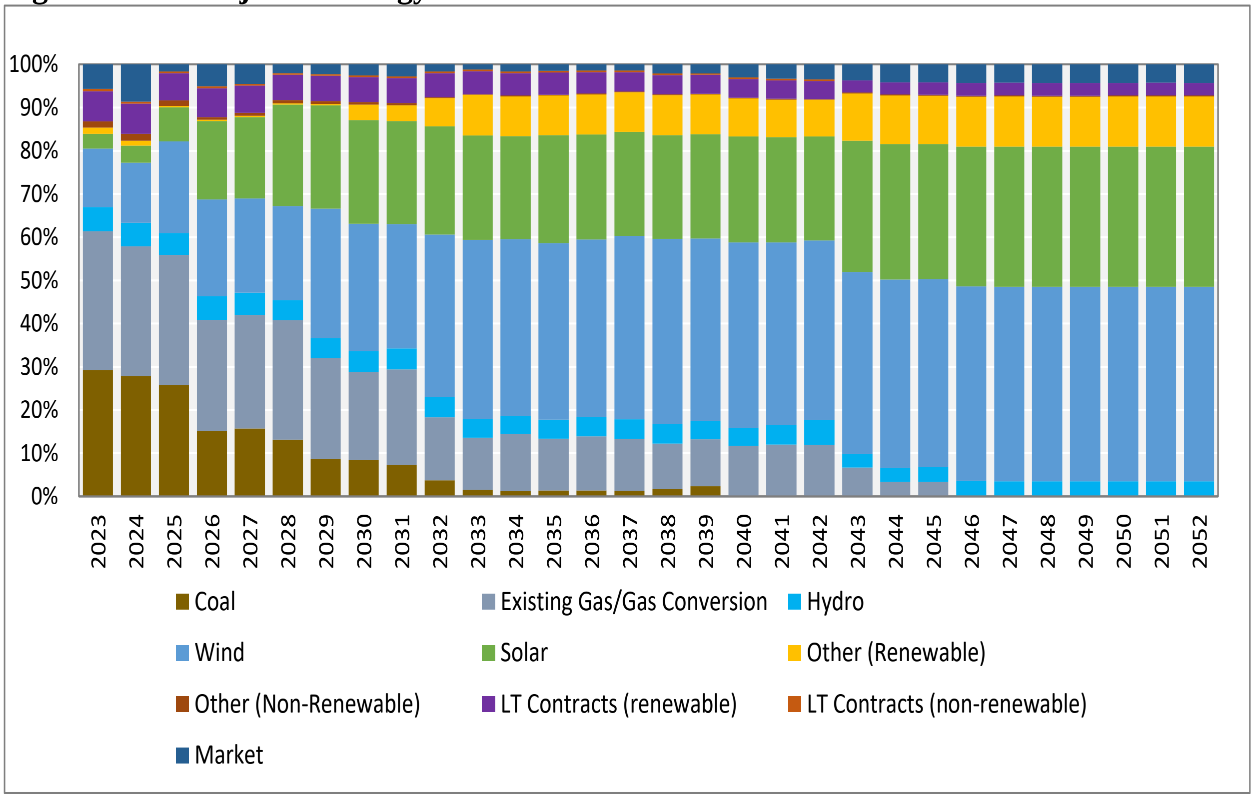
* Includes 13% Planning Reserve Margin, Sales and Non-Owned Reserves
** Includes the storage component of wind and solar collocated with storage
*** Includes retirements, and gas conversions

Figure 9.54 and Figure 9.55 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[4] On an

[4]The projected PacifiCorp 2021 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future

energy basis, coal generation drops to 25 percent by 2027, falls to 9 percent by 2032, and declines to only 1 percent by the end of the planning period. On a capacity basis, coal resources drop to 18 percent by 2027, fall to 11 percent by 2032, and decline to 3 percent by the end of the planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources, DSM resources, and to a smaller extent later in the plan, non-emitting peaker resources.

Figure 9.54 – Projected Energy Mix with Preferred Portfolio Resources



years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2021 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 9.55 – Projected Energy Mix with Preferred Portfolio Resources

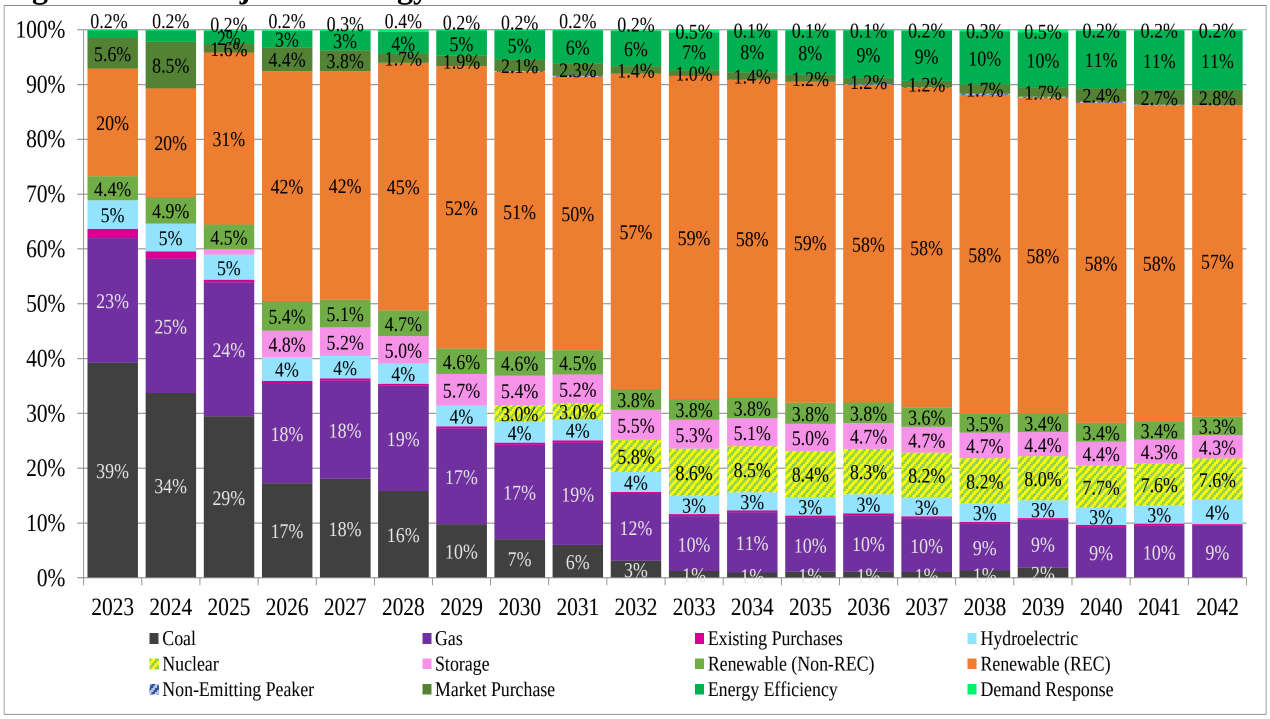


Figure 9.56 – Projected Energy Mix with Preferred Portfolio Resources

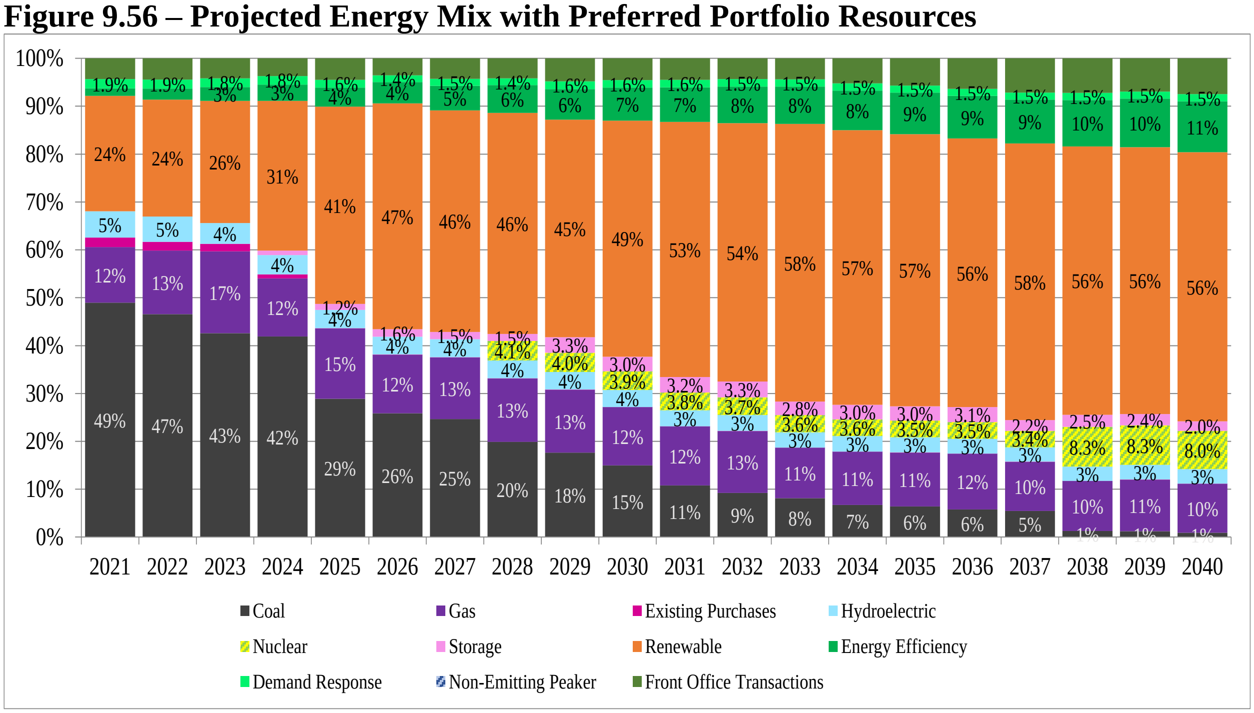


Figure 9.57 – Projected Capacity Mix with Preferred Portfolio Resources

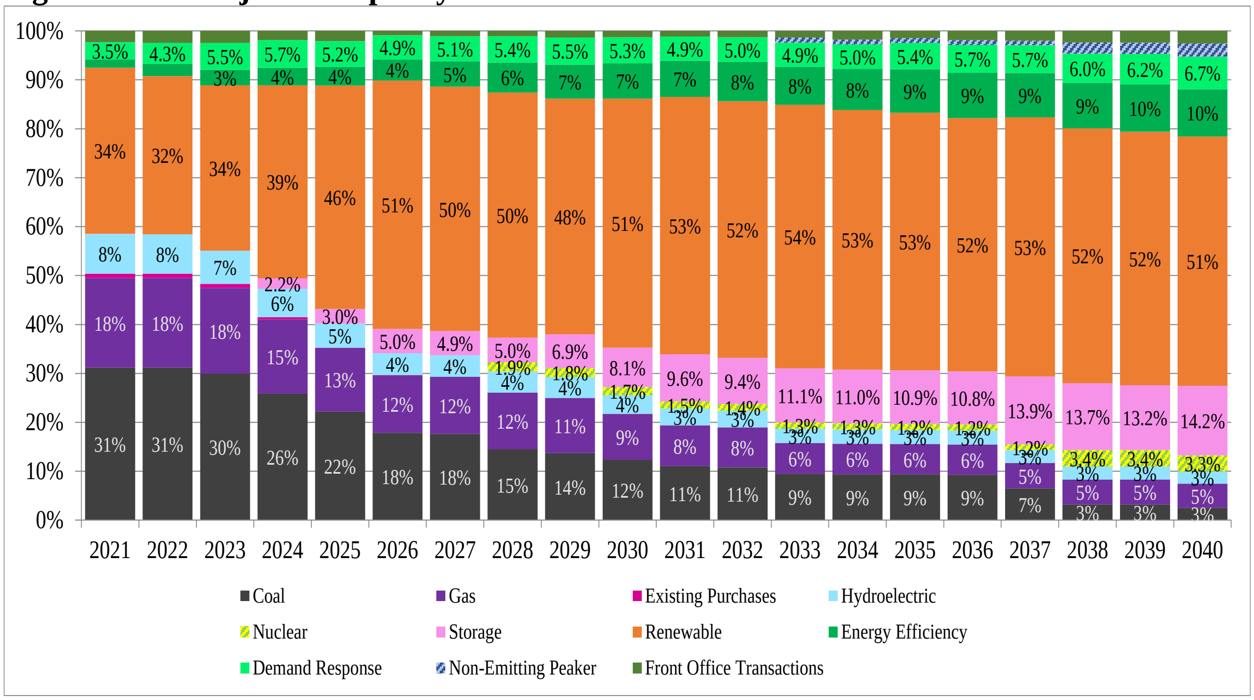


Figure 9.58 – Projected Generation Mix with Preferred Portfolio Resources Reflective of Renewable Claims

Firgure 9.58 shows the generation profile from the preferred portfolio consistent with Figures 9.45 and 9.46 where renewable energy without accompanying RECs is reflected as "unspecified". The RECs associated with "Unspecified" generation were not acquired under current ctonract terms, are claimed by customers under renewable energy terrifs or under contract for sale. The projection does not make assumptions around future REC sales or use of RECs form proxy resources.

Detailed Preferred Portfolio

Table 9.20 provides line-item detail of PacifiCorp's 2023 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 20-year planning horizon. Table 9.21 shows line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 20-year planning horizon. Table 9.22 shows line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the twenty-year planning horizon.

Table 9.20 – PacifiCorp's 2023 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	987	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	166	195	231	52	41	52	52	52	52	52	52	62	46	85	364
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	547	535	587	158	83	53	66	65	48	120	132	182	231	252	595
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,729**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**3,897**	**1,965**	**1,505**	**4,159**	**809**	**234**	**287**	**739**	**1,306**	**(1,095)**	**373**	**(166)**	**416**	**763**	

Table 9.1 – Preferred Portfolio Summer Capacity Load and Resource Balance (2023-2032)

East	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Thermal	5,271	5,056	4,873	4,893	4,857	4,523	4,191	4,332	4,454	3,886
Hydroelectric	87	70	65	65	65	62	60	62	64	59
Renewable	771	648	541	460	480	484	405	412	388	376
Storage	1	1	1	1	1	1	1	1	1	1
Purchase	104	100	31	27	26	23	22	22	23	21
Qualifying Facilities	834	983	576	375	358	329	285	296	275	265
Sale	(21)	0	0	0	0	0	0	0	0	0
East Existing Resources	**7,047**	**6,857**	**6,087**	**5,821**	**5,786**	**5,422**	**4,963**	**5,125**	**5,205**	**4,608**
Market Purchases	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	386	397	368
Wind	10	58	440	367	381	444	667	703	699	965
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	546	801	593	351	331	801	655	683	611	795
Solar+Storage	0	0	1,366	2,685	2,523	2,310	2,250	2,414	2,349	2,340
Storage	0	0	0	0	0	598	691	745	755	754
Nuclear	0	0	0	0	0	0	0	335	342	652
Geothermal	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**556**	**859**	**2,399**	**3,403**	**3,235**	**4,154**	**4,264**	**5,265**	**5,154**	**5,874**
East Total Resources	**7,603**	**7,717**	**8,486**	**9,224**	**9,022**	**9,576**	**9,227**	**10,390**	**10,359**	**10,482**
Load	7,485	7,720	7,889	7,886	8,074	8,406	8,376	8,516	8,731	8,849
Private Generation	(83)	(118)	(157)	(200)	(248)	(301)	(263)	(311)	(364)	(418)
Existing - Demand Response	(159)	(166)	(132)	(112)	(107)	(98)	(93)	(97)	(96)	(87)
New Demand Response	(0)	(2)	(15)	(19)	(33)	(33)	(32)	(35)	(38)	(35)
Existing - Energy Efficiency	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
New Energy Efficiency	(71)	(99)	(162)	(231)	(321)	(412)	(484)	(581)	(739)	(848)
East Total obligation	**7,101**	**7,265**	**7,353**	**7,254**	**7,296**	**7,492**	**7,434**	**7,423**	**7,424**	**7,391**
East Reserve Margin	7%	6%	15%	27%	24%	28%	24%	40%	40%	42%
West										
Thermal	631	603	575	585	579	560	542	468	481	446
Hydroelectric	604	535	515	525	520	502	486	503	517	480
Renewable	120	118	91	87	85	84	80	82	83	70
Purchase	1	1	1	1	1	1	1	1	1	1
Storage	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	255	291	200	150	139	128	110	115	111	105
Sale	(75)	(54)	(51)	(50)	(50)	(48)	(43)	(46)	(47)	(42)
West Existing Resources	**1,536**	**1,493**	**1,331**	**1,297**	**1,274**	**1,226**	**1,176**	**1,123**	**1,148**	**1,061**
Market Purchases	2,832	3,111	2,789	522	396	0	735	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	30	29	28	30	30	288
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	93	114	72	46	43	38	33	34	30	29
Solar+Storage	0	0	14	1,378	1,801	1,650	1,368	1,462	1,438	1,441
Storage	0	0	0	151	237	760	730	785	796	792
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**2,925**	**3,225**	**2,874**	**2,096**	**2,506**	**2,478**	**2,894**	**2,311**	**2,293**	**2,550**
West Total Resources	**4,461**	**4,718**	**4,204**	**3,393**	**3,780**	**3,704**	**4,070**	**3,434**	**3,440**	**3,610**
Load	3,656	3,863	4,067	4,140	4,309	4,481	4,655	4,711	4,873	4,913
Private Generation	(25)	(37)	(51)	(67)	(83)	(101)	(85)	(100)	(117)	(135)
Existing - Demand Response	(8)	(7)	(7)	(6)	(6)	(5)	(5)	(5)	(5)	(5)
New Demand Response	0	(2)	(13)	(17)	(25)	(26)	(27)	(28)	(30)	(28)
Existing - Energy Efficiency	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)
New Energy Efficiency	(37)	(66)	(107)	(125)	(150)	(182)	(193)	(228)	(269)	(277)
West Total obligation	**3,556**	**3,719**	**3,858**	**3,894**	**4,014**	**4,136**	**4,315**	**4,319**	**4,421**	**4,438**
West Reserve Margin	25%	27%	9%	-13%	-6%	-10%	-6%	-20%	-22%	-19%
System										
Total Resources	12,064	12,435	12,691	12,617	12,802	13,280	13,297	13,825	13,799	14,092
Obligation	10,657	10,984	11,211	11,148	11,309	11,628	11,749	11,742	11,844	11,829
Planning Reverve Margin (13%)	1,385	1,428	1,457	1,449	1,470	1,512	1,527	1,526	1,540	1,538
Obligation + Reserves	12,042	12,412	12,669	12,597	12,779	13,139	13,277	13,268	13,384	13,367
System Position	22	23	22	20	22	141	20	557	415	725
Reserve Margin	**13%**	**13%**	**13%**	**13%**	**13%**	**14%**	**13%**	**18%**	**17%**	**19%**

Table 9.21 – Preferred Portfolio Summer Capacity Load and Resource Balance (2033-2042)

East	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	2,555	2,347	2,338	2,759	2,198	1,100	1,111	710	748	827
Hydroelectric	53	53	52	62	57	47	47	41	43	47
Renewable	364	356	332	419	346	300	305	261	257	263
Storage	1	0	0	0	0	0	0	0	0	0
Purchase	19	19	19	22	20	16	16	14	15	17
Qualifying Facilities	241	241	225	261	192	173	170	151	152	154
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**3,232**	**3,017**	**2,966**	**3,523**	**2,812**	**1,636**	**1,649**	**1,178**	**1,215**	**1,308**
Market Purchases	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	327	327	326	384	524	425	430	374	394	435
Wind	951	944	867	1,093	970	914	909	798	812	832
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	755	830	757	906	709	658	659	606	592	574
Solar+Storage	2,328	2,569	2,573	2,669	2,530	2,494	2,497	2,478	2,475	2,484
Storage	1,016	1,151	1,180	1,168	1,550	1,551	1,559	1,573	1,576	1,591
Nuclear	916	965	973	1,067	1,018	907	914	855	878	929
Geothermal	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**6,293**	**6,786**	**6,676**	**7,287**	**7,300**	**6,949**	**6,968**	**6,683**	**6,726**	**6,846**
East Total Resources	**9,526**	**9,803**	**9,642**	**10,810**	**10,112**	**8,584**	**8,617**	**7,861**	**7,941**	**8,154**
Load	8,981	9,134	9,301	9,541	9,680	9,844	9,987	10,160	10,340	10,565
Private Generation	(472)	(522)	(571)	(620)	(668)	(716)	(763)	(808)	(856)	(902)
Existing - Demand Response	(76)	(78)	(78)	(94)	(80)	(66)	(68)	(61)	(65)	(68)
New Demand Response	(30)	(30)	(30)	(36)	(33)	(42)	(44)	(39)	(41)	(46)
Existing - Energy Efficiency	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
New Energy Efficiency	(931)	(1,023)	(1,096)	(1,205)	(1,368)	(1,437)	(1,529)	(1,592)	(1,638)	(1,612)
East Total obligation	**7,402**	**7,411**	**7,456**	**7,518**	**7,461**	**7,514**	**7,515**	**7,591**	**7,671**	**7,867**
East Reserve Margin	29%	32%	29%	44%	36%	14%	15%	4%	4%	4%
West										
Thermal	397	396	395	466	430	234	237	206	217	240
Hydroelectric	426	426	424	501	461	374	379	329	346	383
Renewable	67	68	64	80	65	56	62	54	56	56
Purchase	1	1	1	1	1	1	1	1	1	1
Storage	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	96	97	92	111	90	79	77	68	69	71
Sale	(38)	(38)	(37)	(43)	(40)	(34)	(34)	(29)	(30)	(33)
West Existing Resources	**950**	**949**	**939**	**1,115**	**1,007**	**711**	**722**	**629**	**658**	**716**
Market Purchases	135	0	0	0	0	1,361	1,352	2,478	2,513	2,523
NonEmitting Peaker	0	0	0	219	202	164	166	144	152	168
Wind	559	556	546	663	550	473	519	456	473	466
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	26	27	27	31	24	23	23	22	21	20
Solar+Storage	1,432	1,586	1,592	1,646	1,563	1,552	1,554	1,543	1,540	1,543
Storage	802	905	927	923	922	917	922	927	930	941
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**2,954**	**3,074**	**3,092**	**3,482**	**3,261**	**4,490**	**4,536**	**5,571**	**5,627**	**5,661**
West Total Resources	**3,903**	**4,023**	**4,031**	**4,597**	**4,268**	**5,201**	**5,258**	**6,200**	**6,285**	**6,378**
Load	4,992	5,070	5,147	5,230	5,320	5,400	5,481	5,575	5,667	5,807
Private Generation	(153)	(169)	(185)	(199)	(214)	(228)	(242)	(256)	(270)	(283)
Existing - Demand Response	(4)	(4)	(4)	(5)	(4)	(4)	(4)	(3)	(3)	(4)
New Demand Response	(25)	(25)	(25)	(30)	(27)	(27)	(28)	(25)	(26)	(29)
Existing - Energy Efficiency	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)
New Energy Efficiency	(313)	(337)	(343)	(369)	(406)	(440)	(429)	(423)	(434)	(485)
West Total obligation	**4,467**	**4,504**	**4,559**	**4,597**	**4,638**	**4,670**	**4,747**	**4,839**	**4,903**	**4,976**
West Reserve Margin	-13%	-11%	-12%	0%	-8%	11%	11%	28%	28%	28%
System										
Total Resources	13,429	13,826	13,673	15,407	14,380	13,785	13,875	14,062	14,226	14,532
Obligation	11,869	11,915	12,015	12,115	12,099	12,183	12,262	12,429	12,574	12,843
Planning Reverve Margin (13%)	1,543	1,549	1,562	1,575	1,573	1,584	1,594	1,616	1,635	1,670
Obligation + Reserves	13,412	13,464	13,577	13,689	13,672	13,767	13,856	14,045	14,209	14,513
System Position	18	361	96	1,718	708	18	18	17	18	19
Reserve Margin	**13%**	**16%**	**14%**	**27%**	**19%**	**13%**	**13%**	**13%**	**13%**	**13%**

Table 9.22 – Preferred Portfolio Winter Capacity Load and Resource Balance (2023-2032)

East	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Thermal	5,894	5,321	5,478	5,151	5,547	5,383	4,804	4,613	5,407	4,786
Hydroelectric	71	57	56	54	57	58	54	54	61	58
Renewable	790	999	877	827	921	682	568	585	604	618
Storage	1	1	1	1	1	1	1	1	1	1
Purchase	116	70	34	28	28	27	24	24	27	25
Qualifying Facilities	243	274	234	217	233	183	166	169	182	179
Sale	(23)	0	0	0	0	0	0	0	0	0
East Existing Resources	**7,093**	**6,721**	**6,679**	**6,279**	**6,786**	**6,333**	**5,617**	**5,445**	**6,280**	**5,667**
Market Purchases	453	615	317	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	28	430	482	463
Wind	11	107	728	705	783	700	1,003	1,111	1,234	1,711
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	90	143	121	108	123	140	121	124	116	162
Solar+Storage	0	3	726	1,561	1,504	1,313	1,463	1,472	1,477	1,608
Storage	0	0	0	0	0	480	619	624	629	683
Nuclear	0	0	0	0	0	0	16	340	381	759
Geothermal	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**555**	**867**	**1,891**	**2,373**	**2,410**	**2,633**	**3,251**	**4,100**	**4,320**	**5,386**
East Total Resources	**7,647**	**7,589**	**8,570**	**8,652**	**9,196**	**8,966**	**8,868**	**9,546**	**10,600**	**11,053**
Load	5,833	5,890	6,032	6,039	6,253	6,426	6,496	6,586	6,680	6,739
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(68)	(63)	(59)	(48)	(49)	(46)	(41)	(41)	(47)	(44)
New Demand Response	(0)	(1)	(11)	(19)	(25)	(27)	(24)	(24)	(27)	(26)
Existing - Energy Efficiency	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)
New Energy Efficiency	(41)	(80)	(150)	(180)	(238)	(301)	(346)	(416)	(544)	(598)
East Total obligation	**5,684**	**5,706**	**5,772**	**5,752**	**5,901**	**6,011**	**6,045**	**6,065**	**6,021**	**6,031**
East Reserve Margin	35%	33%	48%	50%	56%	49%	47%	57%	76%	83%
West										
Thermal	745	707	687	672	701	698	655	563	630	606
Hydroelectric	749	692	655	642	670	680	637	637	714	684
Storage	0	0	0	0	0	0	0	0	0	0
Renewable	89	100	91	83	85	72	66	76	83	75
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	81	84	79	72	69	67	60	60	67	61
Sale	(80)	(58)	(55)	(53)	(56)	(48)	(43)	(45)	(50)	(46)
West Existing Resources	**1,586**	**1,526**	**1,459**	**1,417**	**1,470**	**1,471**	**1,377**	**1,292**	**1,445**	**1,381**
Market Purchases	1,057	1,436	739	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	18	17	15	17	24	219
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	6	7	7	6	6	3	2	3	3	2
Solar+Storage	0	0	7	841	1,086	975	896	904	912	983
Storage	0	0	0	132	202	623	661	665	676	727
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,063**	**1,443**	**753**	**979**	**1,313**	**1,618**	**1,574**	**1,590**	**1,615**	**1,932**
West Total Resources	**2,649**	**2,969**	**2,213**	**2,397**	**2,783**	**3,089**	**2,952**	**2,882**	**3,061**	**3,312**
Load	3,485	3,738	3,911	3,993	4,148	4,336	4,397	4,415	4,530	4,562
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	0	0	0	(0)	0	0	0	(0)	(0)	(0)
New Demand Response	0	(15)	(24)	(24)	(27)	(30)	(27)	(26)	(30)	(28)
Existing - Energy Efficiency	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
New Energy Efficiency	(35)	(66)	(98)	(168)	(214)	(244)	(310)	(331)	(360)	(399)
West Total obligation	**3,421**	**3,628**	**3,759**	**3,771**	**3,878**	**4,033**	**4,031**	**4,027**	**4,111**	**4,104**
West Reserve Margin	-23%	-18%	-41%	-36%	-28%	-23%	-27%	-28%	-26%	-19%
System										
Total Resources	10,296	10,558	10,783	11,048	11,979	12,056	11,819	12,427	13,661	14,366
Obligation	9,104	9,334	9,532	9,523	9,779	10,044	10,076	10,092	10,133	10,135
Planning Reverve Margin (13%)	1,184	1,213	1,239	1,238	1,271	1,306	1,310	1,312	1,317	1,318
Obligation + Reserves	10,288	10,548	10,771	10,761	11,050	11,350	11,385	11,404	11,450	11,453
System Position	9	10	12	288	929	706	434	1,023	2,211	2,913
Reserve Margin	**13%**	**13%**	**13%**	**16%**	**23%**	**20%**	**17%**	**23%**	**35%**	**42%**

Table 9.2212 – Preferred Portfolio Winter Capacity Load and Resource Balance (2033-2042)

East	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	3,451	3,007	2,712	2,702	2,471	1,398	1,307	934	876	941
Hydroelectric	56	52	47	49	52	46	44	41	39	42
Renewable	501	491	466	535	507	397	358	364	327	337
Storage	1	0	0	0	0	0	0	0	0	0
Purchase	24	22	20	21	22	20	19	18	17	18
Qualifying Facilities	151	138	127	129	130	107	102	94	91	92
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**4,183**	**3,711**	**3,373**	**3,438**	**3,182**	**1,968**	**1,829**	**1,452**	**1,349**	**1,429**
Market Purchases	0	0	0	0	0	86	219	394	516	482
NonEmitting Peaker	444	416	375	412	613	540	516	484	451	485
Wind	1,419	1,395	1,315	1,529	1,563	1,281	1,154	1,180	1,104	1,124
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	121	108	111	113	108	80	76	75	81	61
Solar+Storage	1,546	1,846	1,859	1,891	1,873	1,868	1,904	1,922	1,940	1,954
Storage	883	1,069	1,076	1,094	1,434	1,443	1,474	1,487	1,498	1,518
Nuclear	1,063	1,083	1,017	1,055	1,088	1,007	989	956	921	966
Geothermal	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**5,476**	**5,916**	**5,753**	**6,094**	**6,679**	**6,305**	**6,334**	**6,497**	**6,511**	**6,590**
East Total Resources	**9,660**	**9,627**	**9,126**	**9,531**	**9,861**	**8,272**	**8,163**	**7,949**	**7,859**	**8,019**
Load	6,882	6,990	7,093	7,171	7,319	7,448	7,592	7,711	7,816	7,969
Private Generation	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Existing - Demand Response	(42)	(39)	(35)	(37)	(39)	(34)	(34)	(32)	(30)	(32)
New Demand Response	(24)	(22)	(20)	(21)	(22)	(20)	(19)	(18)	(17)	(19)
Existing - Energy Efficiency	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)
New Energy Efficiency	(669)	(729)	(770)	(827)	(951)	(986)	(1,025)	(1,090)	(1,057)	(1,144)
East Total obligation	**6,106**	**6,159**	**6,226**	**6,244**	**6,266**	**6,367**	**6,472**	**6,530**	**6,671**	**6,733**
East Reserve Margin	58%	56%	47%	53%	57%	30%	26%	22%	18%	19%
West										
Thermal	575	541	490	514	522	325	307	291	271	291
Hydroelectric	657	616	556	581	614	541	517	484	451	485
Storage	0	0	0	0	0	0	0	0	0	0
Renewable	59	61	54	64	65	51	46	46	46	50
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	57	55	50	52	53	46	44	42	40	42
Sale	(41)	(39)	(36)	(40)	(39)	(34)	(30)	(30)	(27)	(29)
West Existing Resources	**1,308**	**1,234**	**1,116**	**1,172**	**1,216**	**929**	**885**	**834**	**782**	**841**
Market Purchases	0	0	0	0	0	201	511	919	1,204	1,124
NonEmitting Peaker	0	0	24	224	237	208	199	187	174	187
Wind	356	350	312	366	363	302	276	269	270	302
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	2	2	2	1	2	2	1	1	1	2
Solar+Storage	954	1,148	1,154	1,174	1,164	1,165	1,188	1,201	1,211	1,224
Storage	709	848	850	866	859	861	877	883	887	901
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**2,022**	**2,349**	**2,342**	**2,631**	**2,624**	**2,739**	**3,054**	**3,461**	**3,747**	**3,740**
West Total Resources	**3,330**	**3,583**	**3,458**	**3,803**	**3,840**	**3,669**	**3,938**	**4,295**	**4,530**	**4,581**
Load	4,607	4,654	4,702	4,772	4,830	4,878	4,943	4,995	5,054	5,132
Private Generation	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Existing - Demand Response	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
New Demand Response	(27)	(25)	(23)	(24)	(25)	(22)	(21)	(20)	(19)	(21)
Existing - Energy Efficiency	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
New Energy Efficiency	(426)	(469)	(506)	(581)	(597)	(634)	(663)	(648)	(719)	(671)
West Total obligation	**4,124**	**4,130**	**4,143**	**4,137**	**4,177**	**4,192**	**4,228**	**4,297**	**4,285**	**4,410**
West Reserve Margin	-19%	-13%	-17%	-8%	-8%	-12%	-7%	0%	6%	4%
System										
Total Resources	12,990	13,210	12,585	13,334	13,701	11,941	12,101	12,244	12,389	12,600
Obligation	10,230	10,289	10,369	10,381	10,444	10,558	10,700	10,827	10,956	11,142
Planning Reverve Margin (13%)	1,330	1,338	1,348	1,350	1,358	1,373	1,391	1,408	1,424	1,448
Obligation + Reserves	11,560	11,626	11,717	11,731	11,801	11,931	12,092	12,235	12,380	12,591
System Position	1,430	1,584	867	1,603	1,900	10	10	9	9	9
Reserve Margin	**27%**	**28%**	**21%**	**28%**	**31%**	**13%**	**13%**	**13%**	**13%**	**13%**

Washington Scenarios

As described in Chapter 8, Washington's CETA legislation indicates four key studies and sensitivities be analyzed:

- **W-10 CETA**
- **W-11 Climate Change Counterfactual**
- **W-12 Maximum Customer Benefit**
- **P-SC Alternative Lowest Reasonable Cost**

WAC 480-100-620(11)(a) specifically requires the utility to demonstrate how the long-range integrated resource plan expects to achieve clean energy transformation standards (WAC 480-100-610 (1) through (3)), and (j), to incorporate the social cost of greenhouse gas emissions as a cost adder as specific in RCW 19.280.030(3). These specific requirements of an IRP are unique to Washington and the Company must analyze the Washington-compliant portfolio against the system-optimized preferred portfolio to avoid imposing impacts on non-Washington customers.

W-10 CETA is the optimized portfolio developed under the SC price policy and is projected to meet all CETA clean energy targets through 2030 and 2045, specifically meeting all requirements set out in WAC 480-100-620(11).[5] The W-10 CETA portfolio is developed for Washington, based on a starting point of the Alternative Lowest Reasonable Cost, P-SC. Discussion of CETA compliance and development of the portfolio to meet CETA targets can be found in Volume II, Appendix O.

In this section, PacifiCorp discusses the W-10 CETA portfolio selections and each of the additional scenario outcomes relative to the W-10 portfolio and the system optimized preferred portfolio P-MM dispatched under SC.

W-10 CETA

The W-10 CETA portfolio is nearly identical to the P-SC portfolio: the portfolio is optimized across existing coal and gas resources and new proxy resources under the SC price policy assumption, but includes incremental resources to Washington customers for CETA-compliance in 2030 and 2031.

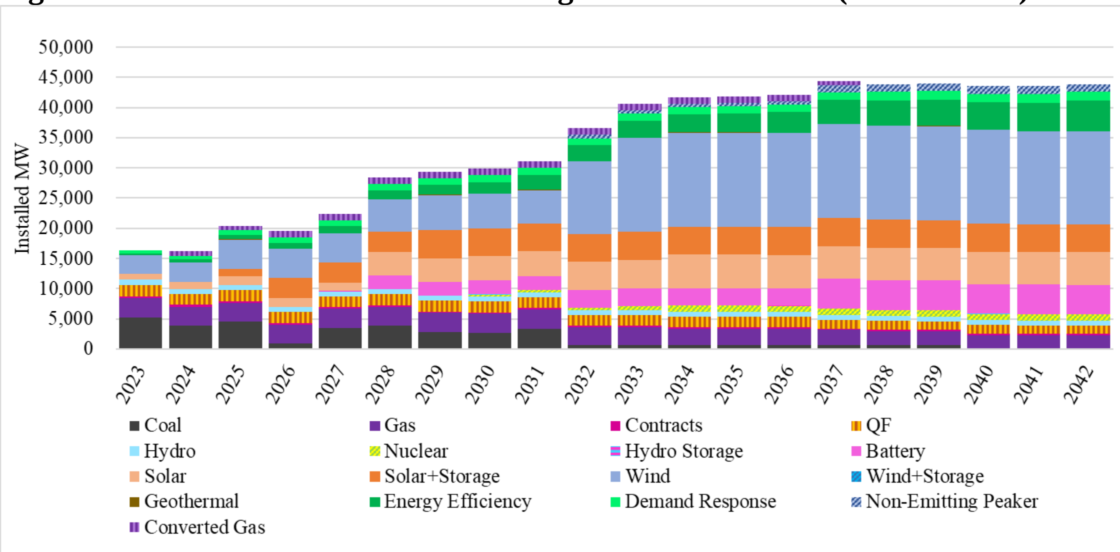
The W-10 CETA system portfolio results in 13,081 MW of new wind capacity, 8,625 MW of solar, and 9,171 MW of storage co-located with renewables, where 1,184 MW of that storage capacity is long-duration battery. The new solar and wind capacity includes 120 MW of small-scale wind capacity and 120 MW of small-scale solar capacity located in Yakima, Washington that were added as incremental resources needed for CETA compliance in 2030 onwards. The small-scale resources do incur higher build costs than utility-scale renewables, but do not require additional transmission capacity to generate.

Additionally, the portfolio selects 1,240 MW of non-emitting peakers, 1,500 MW of advanced nuclear technology, and 35 MW of pumped hydro. There are no new emitting resources added to the portfolio over the planning horizon. In the W-10 CETA portfolio all coal-fueled resources are

[5] W-10, the CETA-compliant portfolio, is also considered the Clean Energy Implementation Plan (CEIP) Portfolio.

retired before 2040 and all gas-fueled resources by 2048, but most notably for Washington customers specifically is the conversion of Jim Bridger coal units 1 and 2 to gas-fired in 2024.[6] For demand-side management resources in Washington there is a selection of 206.2 MW of energy efficiency and 104.5 MW of demand-response in total across the period. Cumulative portfolio resource additions for system-wide results for W-10 CETA are shown in Figure 9.59.

Figure 9.59 – Cumulative Portfolio Changes for W-10 CETA (all resources)

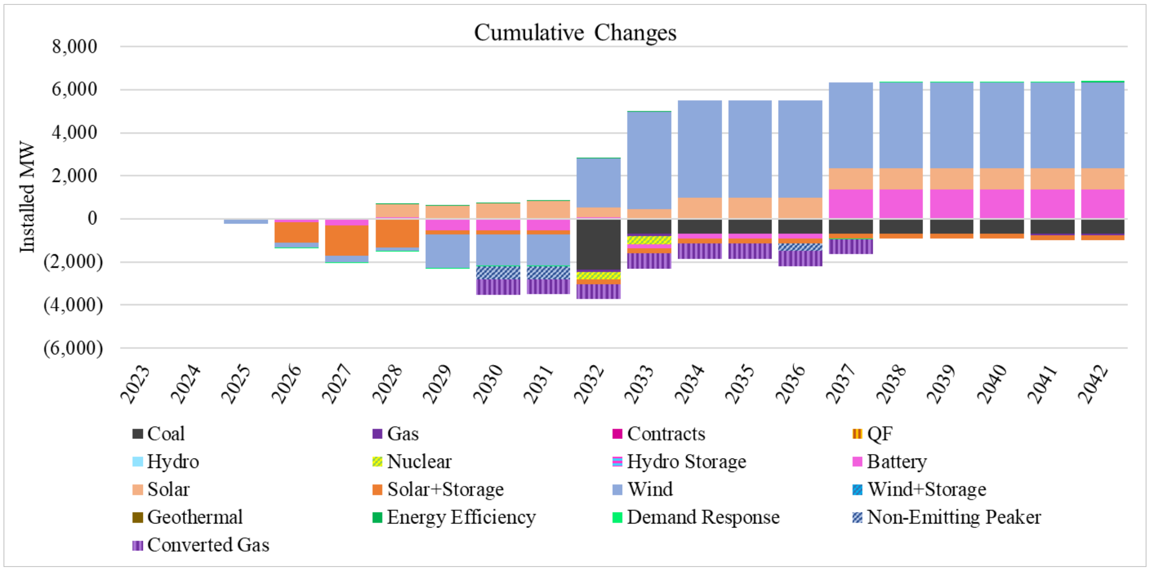


The W-10 CETA portfolio results in a risk-adjusted PVRR of $55.52 billion. For contrast, the W-10 CETA portfolio is an estimated $18.40 billion more expensive than the system preferred portfolio, P-MM. The cost differential is partly a result of the the SC price policy assumption versus the medium carbon price. When the preferred portfolio is run under the SC price policy in operations (after the optimal portfolio was developed under the medium carbon price scenario) the portfolio performs less efficiently, resulting in a PVRR(d) of $58.24 billion, which is almost $3 billion more expensive than W-10.

In terms of resource differences between W-10 CETA and P-MM, the CETA-compliant portfolio adds 5,763 MW more capacity across the planning horizon. The cumulative differences in the W-10 CETA portfolio relative to P-MM are shown in Figure 9.60

[6] Thermal retirements are fully optimized at the system level in the W-10 portfolio while the model remains agnostic about any state-specific allocations of resources. To the extent that an early thermal retirement is triggered under the SC price-policy assumption only, and is not cost-allocated to Washington customers, the retirement may not be considered optimal for the rest of the system.

Figure 9.60 – Cumulative Portfolio Resource Changes W-10 CETA compared to the 2023 IRP Preferred Portfolio



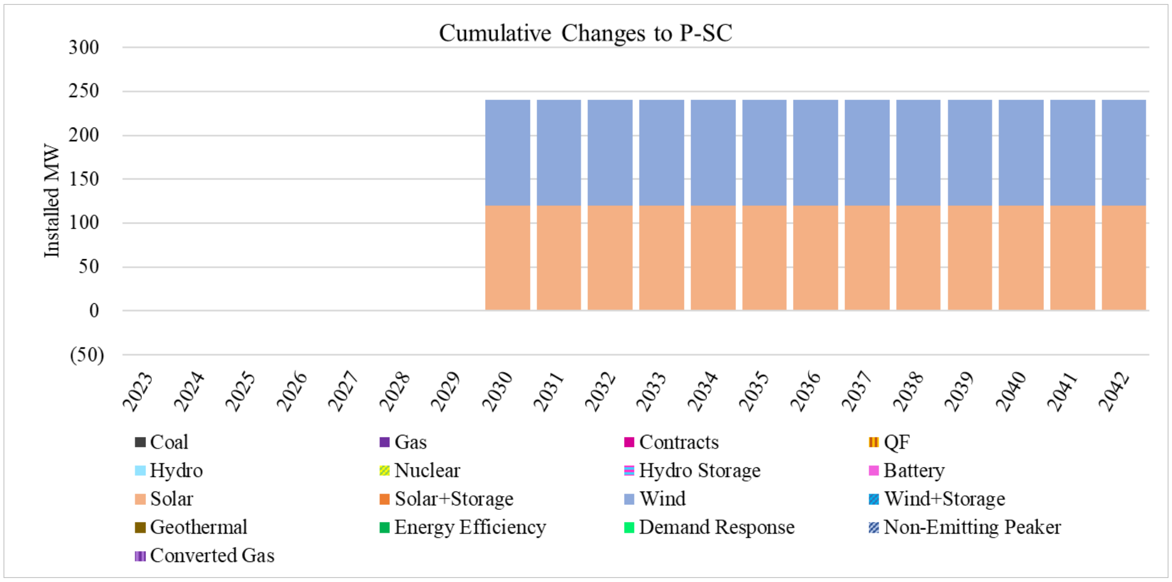
Alternative Lowest Reasonable Cost

WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's directives and must include the social cost of greenhouse gases (SC) in the resource acquisition decision. Thus, the system-optimized portfolio developed under the SC price-policy assumption, P-SC, is the Alternative Lowest Reasonable Cost scenario that would have resulted but not for CETA. This portfolio serves as the basis for assessing Washington-allocated energy and development of the CETA-compliant portfolio as discussed in Volume II, Appendix O (Washington Two-Year Progress Report Additional Elements).

The W-10 CETA-compliant portfolio is $10 million cheaper on a PVRR(d) basis, as compared to the Alternative Lowest Reasonable Cost portfolio. Despite the incurred incremental build costs in the W-10 CETA portfolio due to the additional small-scale wind and solar capacity, there is a positive offset in cost from a reduction in greenhouse gas emissions and coal fuel – a direct result of increased renewable generation. These costs are on a system risk-adjusted PVRR basis, however, and are not necessarily reflective of Washington-allocated cost impacts.

Figure 9.61 shows the cumulative portfolio resource changes of W-10 CETA as compared to P-SC. The figure depicts the incremental small-scale wind and solar resources that were added to the P-SC portfolio to meet CETA clean energy targets in 2030 and 2031.

Figure 9.61 – Cumulative Portfolio Resource Changes W-10 CETA compared to P-SC Alternative Lowest Reasonable Cost



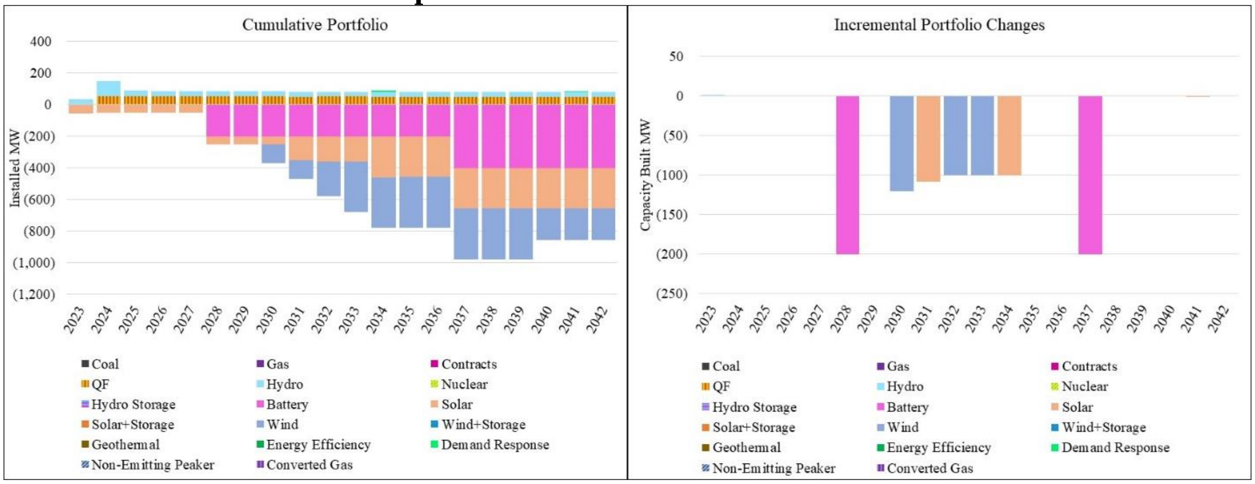
Climate Change Counterfactual

The base 2023 IRP includes an updated load forecast to incorporate regional studies on potential temperature change (and associated impact to demand and energy). Relative to the 20-year normal scenario, the base 2023 IRP results in summer peaks being higher by approximately 30 MW (<1% higher) over the 2023-2027 timeframe. By 2042, summer peaks are projected to be 474 MW (2.7%) higher than the 2021 IRP Base. Higher winter temperatures result in less heating load, which are driving lower winter peaks. By 2040, winter peaks are projected to be 259 MW (3.1%) higher than the 20-year normal scenario. Please see Appendix A for additional detail regarding how climate change is incorporated into the base 2023 IRP.

The scenario also includes analysis of impacts from climate change (precipitation, streamflow, etc.) on hydroelectric generating facilities on the Lewis River, North Umpqua River, and Rogue River systems. The impact analysis projects seasonally lower natural streamflows during summer months and higher winter season streamflows. Over the 20-year planning period, the analysis indicates that annual streamflow volumes for the North Umpqua River and Rogue River remain relatively constant, while annual streamflow volume for the Lewis River is projected to increase over the 20-year planning period by up to about 4%. In addition to the changes in hydro capacity due to climate change, the decrease in load against the base load forecast led to a reduction in resource selections. This case selected 400 MW less storage, and just over 200 MW less solar and wind each.

Compared to W-10 CETA portfolio, the exclusion of climate change temperatures and precipitation effects increases system risk-adjusted PVRR by $858 million. The cumulative portfolio resource changes in the no climate change portfolio compared to W-10 CETA are shown in Figure 9.62.

Figure 9.62 – Cumulative and Incremental Portfolio Resource Changes, Climate Change Counterfactual Portfolio Compared to W-10 CETA

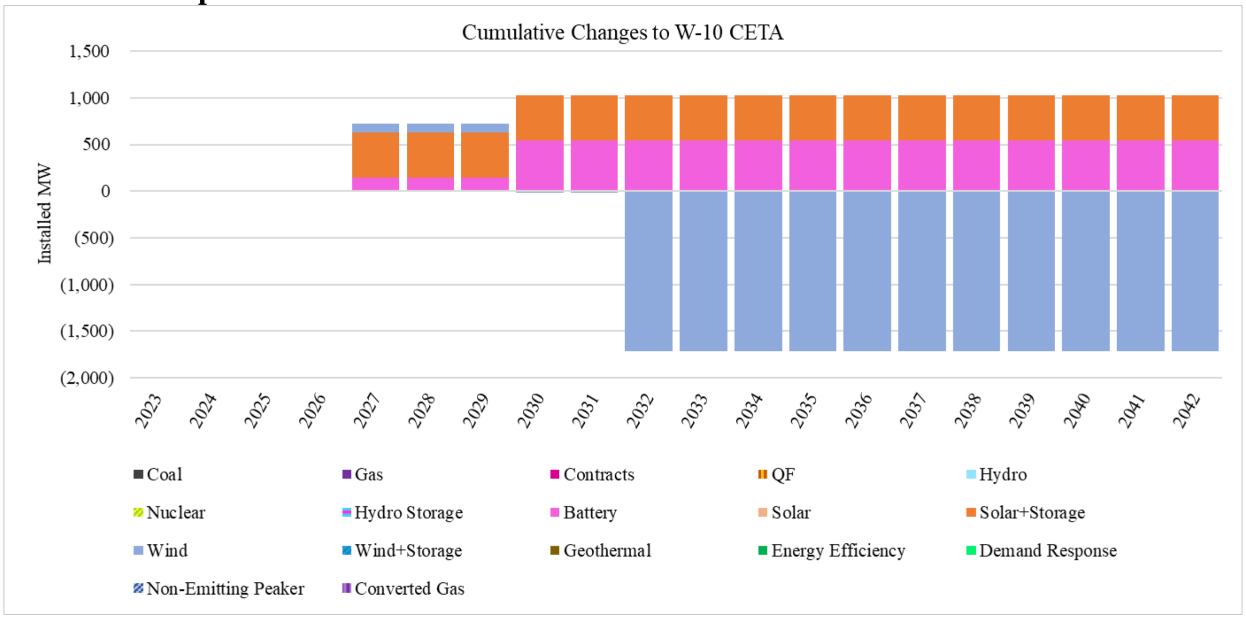


Maximum Customer Benefit

The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and is assumed to be CETA-compliant. All available Washington energy efficiency and demand response is added, beyond what was already selected in the W-10 CETA portfolio. The Maximum Customer Benefit portfolio results in $2.77 billion more on a PVRR(d) basis as compared to W-10 CETA portfolio. The cumulative portfolio resource changes in the Maximum Customer Benefit portfolio relative to W-10 CETA are shown in Figure 9.63.

As a result of the requirement to remove high voltage transmission options, over 1,500 MW of wind located in Walla Walla is forced to come out of the portfolio. This wind is highly beneficial to the system as a whole, and is a major contributor to the higher costs. The removal of these lines also necessitates additional storage and solar to be built throughout the system as resources which would have been able to reach the rest of the west side of the system now may not do so as effectively. This reduction in system flexibility also contributes to the higher cost.

Figure 9.63 – Cumulative Portfolio Resource Changes, Maximum Customer Benefit Portfolio Compared to W-10 CETA Portfolio



The portfolios run under the SC price policy assumption are shown in Table 9.23. All portfolios shown in the table, except the first row (the preferred portfolio) were developed under the SC price policy assumption in the capacity expansion decision, per Washington rule. The system preferred portfolio was developed under the medium carbon price assumption, but is shown here dispatched with SC in operations, for comparison. The W-10 CETA portfolio is the best performing portfolio scenario across the SC portfolios and serves as the basis for the Washington Clean Energy Implementation Plan (CEIP) as described in Volume II, Appendix O.

Table 9.23 – All Washington-required portfolios and portfolios run under the SC price policy assumption

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - SC	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P-MM	58,238	$2,722	4	58,192	$2,885	5	0.0020%	-0.00003%	2	332,257	12,250	5
P-SC	55,525	$10	2	55,329	$22	2	0.0020%	0.00000%	5	321,100	1,094	4
W-10 SC CETA	55,516	$0	1	55,307	$0	1	0.0020%	0.00000%	4	320,006	0	3
W-11 CETA No Climate	56,374	$859	3	56,142	$835	3	0.0019%	-0.00013%	1	318,685	-1,322	2
W-12 CETA Max Benefit	58,279	$2,763	5	58,111	$2,804	4	0.0020%	0.00000%	3	310,798	-9,208	1

Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the portfolio-development process that supports selection of the preferred portfolio, sensitivity cases will be completed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. These sensitivity cases are useful in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risk.

Table 9.24 lists additional sensitivity studies to be performed for the 2023 IRP. To isolate the impact of a given planning assumption, all sensitivity cases will be evaluated with the preferred portfolio.

Table 9.24 – Summary of Additional Sensitivity Cases

Case	Description	Risk-Adjusted PVRR ($m)	Load	Private Gen	CO_2 Policy
S-01	High Load	High	Low	Optimized	Medium gas / Medium CO_2
S-02	Low Load	Low	High	Optimized	Medium gas / Medium CO_2
S-03	1 in 20 Load Growth	1 in 20	Base	Optimized	Medium gas / Medium CO_2
S-04	20-year Normal	20yr Normal	Base	Optimized	Medium gas / Medium CO_2
S-05	High Private Generation	Base	High	Optimized	Medium gas / Medium CO_2
S-06	Low Private Generation	Base	Low	Optimized	Medium gas / Medium CO_2
S-07	Business Plan	Base	Base	Align first three years	Medium gas / Medium CO_2
S-08	New Load	Flat Load Increase	Base	Optimized	Medium gas / Medium CO_2
W-10	CETA	Base	Base	Added for CETA	WA resources under SC
W-11	Climate Change Counterfactual	No climate change	Base	Optimized	WA resources under SC
W-12	Max Customer Benefit	Base	Base	Modified	WA resources under SC

PacifiCorp will file a supplemental filing to its 2023 IRP filing that includes discussion and results of these sensitivities. The supplemental filing will also be posted to PacifiCorp's IRP webpage at the following location: www.pacificorp.com/energy/integrated-resource-plan.

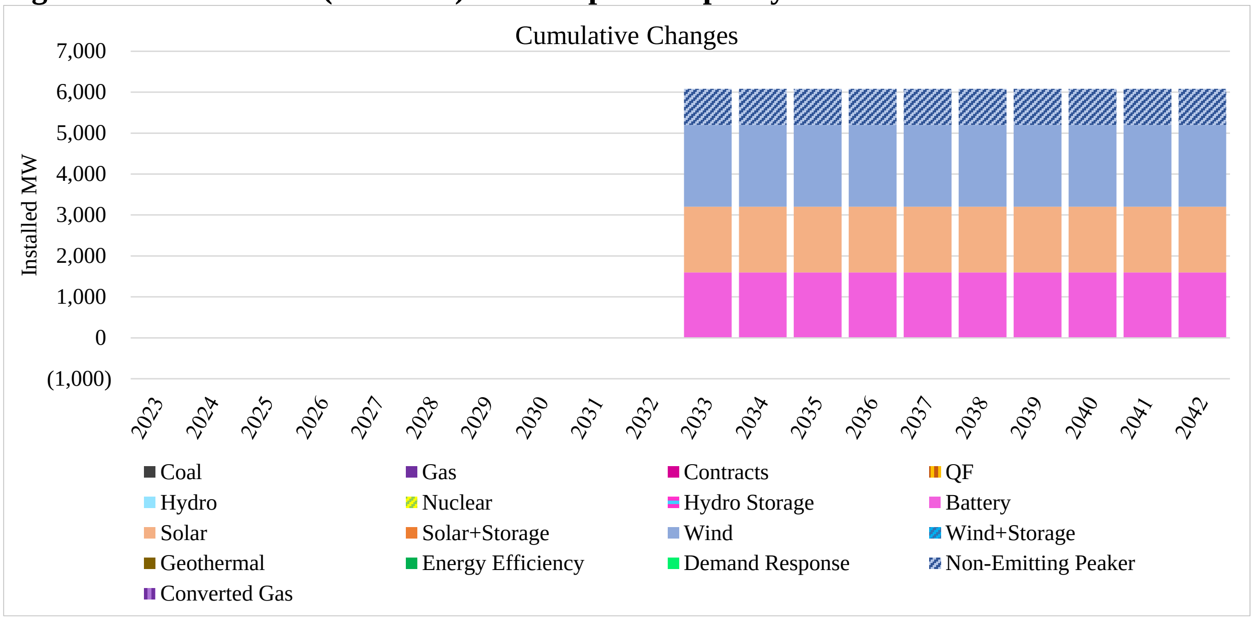
New Load Sensitivity (S-08)

shows the PVRR impacts of the S-08 sensitivity relative to preferred portfolio. Higher loads result in increased resource requirements which translate into higher system costs. Table 9.25 summarizes the portfolio impacts. The new loads, approximate 3000 GW, in 2033 required the addition of wind, solar, battery and non-emitting peakers. Transmission was required to integrate renewables are Boardman to Heminway 2, Gateway South 2, D3-2, and D2-3, Segment E and Segment E 2 In combination, this resulted in higher fixed costs offset by lower fuel costs, lower emission costs, and lower market purchases. CO_2 emissions over the study period decreased by 19 million tons.

Table 9.25 – Risk-Adjusted PVRR (Benefit)/Cost of S-01 vs. P-MM

Medium Gas - Medium CO_2 ($ Million)		
P-MM	**S-08**	**(Benefit) / Cost Relative to P-MM**
$37,305	$40,846	$3,541

Figure 9.64 – Increase/(Decrease) in Nameplate Capacity of S-08 Relative to



Additional CCUS Sensitivities

Dave Johnston Unit 2 Converts to CCUS in 2028

The DJ2 CCUS portfolio is a variant of the preferred portfolio that forces a CCUS retrofit on Dave Johnston Unit 2 in 2028 to enable the project to qualify for existing tax credits. When this variant is compared to the preferred portfolio, changes in proxy resources and system costs driven by the CCUS retrofit can be isolated. Because CCUS was not selected as a least-cost resource option in the preferred portfolio, this variant was produced to evaluate a means to comply with Wyoming House Bill 200 (HB 200). HB 200 was passed by the Wyoming Legislature in March 2020, and it requires the Wyoming Public Service Commission to establish a standard that specifies a percentage of electricity that must be generated from coal-fired generation using carbon capture technology by 2030, subject to an incremental cost limitation of 2% of Wyoming customers' total bill to comply with the standard.

For modeling purposes, PacifiCorp chose to force a CCUS retrofit (amine based post-combustion + enhanced oil recovery) at Dave Johnston Unit 2 for the following reasons:

- There are no complications with co-ownership as would be the case with Wyodak or the Jim Bridger units
- Expectation of higher costs associated with necessary inlet NO_X and SO_2 controls relative to Dave Johnston Units 2
- Installation of CCUS at Dave Johnston Unit 2 would be expected to meet preliminary HB 200 targets

This modeling assumption does not mean PacifiCorp has determined Dave Johnston Unit 2 is the only site for a CCUS retrofit. As described in the 2023 IRP action plan, PacifiCorp is engaged in a request for expressions of interest process and has issued a request for proposals that will help identify candidates for potential CCUS retrofits and help refine cost-and-performance assumptions.

The installation of CCUS in 2028 replaces the coal unit. The CCUS extends the life of Dave Johnston Unit 2 to year end 2039 with a retrofit installed. There is a net reduction of capacity due to the parasitic load associated with the carbon capture equipment.[7]

Figure 9.65 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when CCUS is installed on Dave Johnston Unit 2 in 2028. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2039, the PVRR(d) shows that the portfolio with CCUS installed on Dave Johnston Unit 2 project is $514 million higher cost than the preferred portfolio.

When the CCUS retrofit is installed in 2028, the carbon capture technology increases the costs associated with Dave Johnston Unit 2. This shows up as increased fixed costs for coal and gas resources in the chart at left. This is partially offset by reduced emissions costs.

[7] Upon installation of the carbon capture equipment, Dave Johnston Unit 2's rating is 76 MW. As a coal-fired facility without carbon capture equipment, Dave Johnston Unit 2's rating is 106 MW.

Figure 9.65 – Increase /(Decrease) in System Costs when CCUS is Installed on Dave Johnston Unit 2 in 2028.

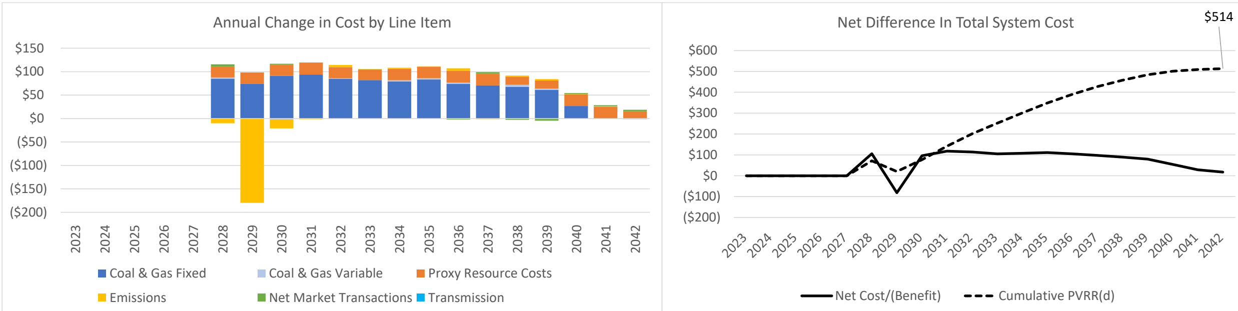


Figure 9.65 summarizes the PVRR(d) of the P20-DJ2 CCUS portfolio relative to the preferred portfolio under a range of different price-policy scenarios. The portfolio that includes the CCUS retrofit at Dave Johnston Unit 2 is higher cost than the preferred portfolio across each of the price-policy scenarios. This trend holds true for both the ST PVRR and the risk-adjusted PVRR results. Both portfolios, as measured by ENS, are very reliable. Emissions are slightly lower when CCUS is installed on Dave Johnston Unit 2. The magnitude of the increased cost in the portfolio that includes a CCUS retrofit on Dave Johnston Unit 2 in 2028, which would be situs-assigned to Wyoming customers, is expected to exceed the cost containment language set forth in HB 200, and for this reason, it is not included in the preferred portfolio. Nonetheless, PacifiCorp recognizes that this analysis is driven by a wide range of assumptions specific to the cost and commercial structure of CCUS opportunities. Consequently, PacifiCorp has established an action plan with a CCUS action item to continue with the on-going request for expressions of interest process and to proceed with a request for proposals process that will help identify potential sites, costs, and commercial structures that will allow us to update this analysis after the 2023 IRP.

Dave Johnston Unit 4 Converts to CCUS in 2028 Variant (DJ4 CCUS)

The DJ4 CCUS portfolio is a variant of the preferred portfolio that forces a CCUS retrofit on Dave Johnston Unit 4 in 2028 to enable the project to qualify for existing tax credits. When this variant is compared to the preferred portfolio, changes in proxy resources and system costs driven by the CCUS retrofit can be isolated. Because CCUS was not selected as a least-cost resource option in the preferred portfolio, this variant was produced to evaluate a means to comply with Wyoming House Bill 200 (HB 200). HB 200 was passed by the Wyoming Legislature in March 2020, and it requires the Wyoming Public Service Commission to establish a standard that specifies a percentage of electricity that must be generated from coal-fired generation using carbon capture technology by 2030, subject to an incremental cost limitation of 2% of Wyoming customers' total bill to comply with the standard.

For modeling purposes, PacifiCorp chose to force a CCUS retrofit (amine based post-combustion + enhanced oil recovery) at Dave Johnston Unit 4 for the following reasons:

- There are no complications with co-ownership as would be the case with Wyodak or the Jim Bridger units
- CCUS at Dave Johnston Unit 4 would not require a new lined coalcombustion residual impoundment as would be the case at the Naughton coal units
- Expectation of lower costs associated with necessary inlet NO_X and SO_2 controls relative to Dave Johnston Units 1 and 2
- Dave Johnston Unit 3 has a federal closure commitment under EPA's regional haze rule. Installation of CCUS at Dave Johnston Unit 4 would be expected to meet preliminary HB 200 targets

This modeling assumption does not mean PacifiCorp has determined Dave Johnston Unit 4 is the only site for a CCUS retrofit. As described in the 2023 IRP action plan, PacifiCorp is engaged in a request for expressions of interest process and will soon be issuing a request for proposals that will help identify candidates for potential CCUS retrofits and help refine cost-and-performance assumptions.

The installation of CCUS in 2028 replaces the coal unit. The CCUS does not extend the life of Dave Johnston 4 beyong 2039. There is a net reduction of capacity due to the parasitic load associated with the carbon capture equipment.[8]

Figure 9.66 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when CCUS is installed on Dave Johnston Unit 4 in 2028. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio with CCUS installed on Dave Johnston Unit 4 project is $857 million higher cost than the preferred portfolio.

When the CCUS retrofit is installed in 2028, the carbon capture technology increases the costs associated with Dave Johnston Unit 4. This shows up as increased fixed costs for coal and gas resources in the chart at left. This is partially offset by reduced emissions costs.

[8] Upon installation of the carbon capture equipment, Dave Johnston Unit 4's rating is 233 MW. As a coal-fired facility without carbon capture equipment, Dave Johnston Unit 4's rating is 330 MW.

Figure 9.66 – Increase/(Decrease) in System Costs when CCUS is Installed on Dave Johnston Unit 4 in 2028

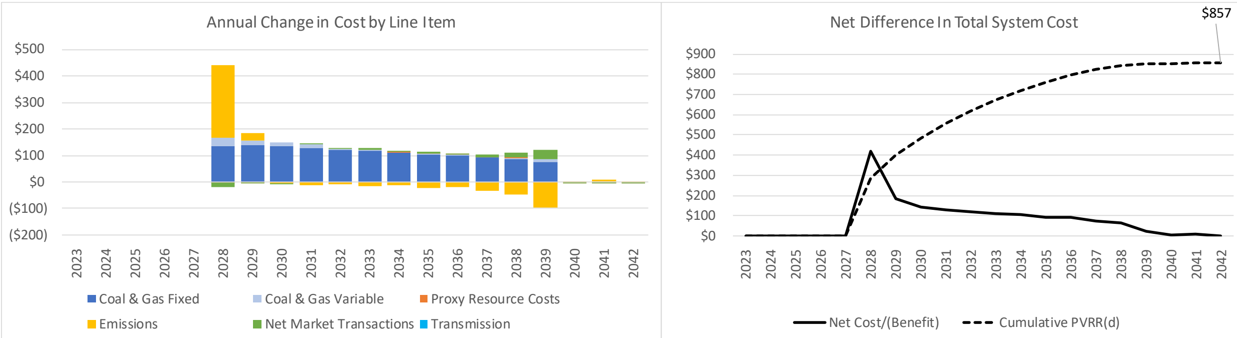


Figure 9.66 summarizes the PVRR(d) of the P21-DJ4 CCUS portfolio relative to the preferred portfolio under a range of different price-policy scenarios. The portfolio that includes the CCUS retrofit at Dave Johnston Unit 4 is higher cost than the preferred portfolio. This trend holds true for both the ST PVRR and the risk-adjusted PVRR results. Both portfolios, as measured by ENS, are very reliable. Emissions are slightly lower when CCUS is installed on Dave Johnston Unit 4. The magnitude of the increased cost in the portfolio that includes a CCUS retrofit on Dave Johnston Unit 4 in 2028, which would be situs-assigned to Wyoming customers, is expected to exceed the cost containment language set forth in HB 200, and for this reason, it is not included in the preferred portfolio. Nonetheless, PacifiCorp recognizes that this analysis is driven by a wide range of assumptions specific to the cost and commercial structure of CCUS opportunities. Consequently, PacifiCorp has established an action plan with a CCUS action item to continue with the on-going request for expressions of interest process and to proceed with a request for proposals process that will help identify potential sites, costs, and commercial structures that will allow us to update this analysis after the 2023 IRP.

CHAPTER 10 – ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2023 Integrated Resource Plan (IRP) action plan identifies steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio.
- PacifiCorp's 2023 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).
- The 2023 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and carbon dioxide (CO_2) emission polices.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2023 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver its preferred portfolio, with a focus on the front ten years of the planning horizon. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions and other trigger events during the action plan time frame that could materially impact resource acquisition strategies.

The 2023 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2023 IRP, such as capital and operating costs, are based upon recent cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the 2023 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2023 IRP acquisition path analysis, this chapter also includes discussion of the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;

- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2023 IRP Action Plan

The 2023 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2023 IRP public-input process. Table 10.1 details specific 2021 IRP action items by resource category.

Table 10.1 – 2023 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**<u>Colstrip Units 3 and 4:</u>** • PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030.
1b	**<u>Craig Unit 1:</u>** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP preferred portfolio target exit date of December 31, 2025.
1c	**<u>Naughton Units 1 and 2:</u>** • PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**<u>Jim Bridger Units 1 and 2 Gas Conversion:</u>** • PacifiCorp has initiated the process of ending coal-fueled operations. The Wyoming Air Quality Division issued an air permit on December 28, 2022, for the natural gas conversion. All required regulatory notices and filings will be completed by end of 2023. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.

1e	**<u>Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:</u>** • PacifiCorp will complete evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023. • PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024.
1f	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.
1g	**<u>Natrium™ Demonstration Project:</u>** • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project. • By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders. • By 2027, PacifiCorp will begin training operators. PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.
1h	**<u>Ozone Transport Rule Compliance:</u>** • PacifiCorp will assess the impact of EPA's finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective. • Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2023, which may necessitate issuance of a request for proposals to procure resources within the action plan window.
2b	**2024 All-Source Request for Proposals:** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the 2023 IRP preferred portfolio that can achieve commercial operations by the end of December 2028. • In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier.

2c	**<u>2022 All-Source Request for Proposals:</u>** • In April 2022 PacifiCorp issued an all-source Request for Proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2027. • In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for any applicable significant energy resources on final shortlist. PacifiCorp will file certificate of public convenience and necessity (CPCN) applications, as applicable, and • By Q4 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the 2022 all-source RFP are expected to achieve commercial operation by December 31, 2027, or earlier.

Action Item	3. Transmission Action Items
3a	**<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>** • In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service.
3b	**<u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u>** • In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service.
3c	**<u>Boardman-to-Hemingway (500 kV transmission line):</u>** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in "pre-construction" activities in support of the 2026 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids
3e	Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>4a</td><td>
<u>Energy Efficiency Targets:</u>

PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp’s state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP.
PacifiCorp will pursue cost-effective energy efficiency resources as summarized in the table below:
<table>
<tr><th>Year</th><th>Annual 1st Year Energy (GWh)</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2023</td><td>543</td><td>123</td></tr>
<tr><td>2024</td><td>551</td><td>220</td></tr>
<tr><td>2025</td><td>596</td><td>259</td></tr>
<tr><td>2026</td><td>563</td><td>197</td></tr>
</table>

PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity[1] selections from the preferred portfolio[2] as summarized in the table below:
<table>
<tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2023</td><td>72</td></tr>
<tr><td>2024</td><td>39</td></tr>
<tr><td>2025</td><td>152</td></tr>
<tr><td>2026</td><td>109</td></tr>
</table>

[1] Capacity impacts for demand response include both summer and winter impacts within a year.
[2] A portion of cost-effective demand response resources identified in the 2021 2023 preferred portfolio in 2023 for Oregon and Washington represent planned volumes expected are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources offered through approved programs. subsequently procured under the previously issued RFP in compliance with state level procurement requirements.
</td></tr>
</table>

Action Item	5. Market Purchases
5a	**Market Purchases:** • Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
Action Item	**6. Renewable Energy Credit (REC) Actions**
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2024 and future compliance periods, as needed.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Progress on 2021 Action Plan

This section describes progress that has been made on previous action plan items documented in the 2021 IRP filed with state commissions on September 1, 2021. Many of these action items have been superseded in some form by items identified in the 2023 IRP action plan. The status for all action items from the 2023 IRP is summarized in Table 10.2.

Table 10.2 – 2021 IRP Action Plan Status Update

Action Item	1. Existing Resource Actions	Status
1a	**<u>Colstrip Units 3 and 4:</u>** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.	PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP preferred portfolio target exit date of December 31, 2025 for Colstrip Unit 3, and December 31, 2029 for Colstrip Unit 4.
1b	**<u>Craig Unit 1:</u>** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.	PacifiCorp is proceeding with this action item on schedule.
1b	**<u>Naughton Units 1 and 2:</u>** • PacifiCorp will initiate the process of retiring Naughton Units 1-2 by the end of December 2025, including completion of all required regulatory notices and filings. • By the end of Q2 2023, PacifiCorp will confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, PacifiCorp will initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2.	PacifiCorp will initiate the processes for permitting and converting Naughton Units 1 and 2 to natural gas. Additional information on this action item is included in the 2023 action plan.

	• By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	
1c	**<u>Jim Bridger Units 1 and 2 Gas Conversion:</u>** • PacifiCorp will initiate the process of ending coal-fueled operations and seeking permitting for a natural-gas conversion by 2024, including completion of all required regulatory notices and filings. • By the end of Q2 2022, PacifiCorp will finalize an employee transition plan. • By the end of Q2 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements. •	PacifiCorp is proceeding with this action item on schedule. Additional information on this action item is included in the 2023 action plan.
1d	**<u>Carbon Capture, Utilization, and Sequestration/Wyoming House Bill 200 Compliance:</u>** • PacifiCorp issued a carbon capture, utilization, and sequestration (CCUS) request for expression of interest (REOI) on June 29, 2021. PacifiCorp will complete the 2021 CCUS REOI process and utilize any new relevant information. Additional model sensitivities will be run accordingly. • PacifiCorp will issue a CCUS Request for Proposals (RFP) in 2022. The 2021 CCUS REOI responses will inform the scope of the CCUS RFP. • A completed CCUS Front End Engineering & Design Study (FEED Study) based on a new CCUS technology was submitted to PacifiCorp in July 2021 for Dave	• The CCUS REOI was completed in 2021. The REOI responses informed the Company's feasibility analysis, completed in 2022 as part of Wyoming HB 200 compliance. • PacifiCorp issued two CCUS Request for Proposals (RFP), one for Dave Johnston Unit 4 and one for Jim Bridger Units 3 and/or 4, on November 1, 2022. Proposals were due March 7, 2023, and the company is evaluating information received. Where appropriate, information received from the RFP process will be used to update and inform model sensitivities that can

	Johnston Unit 2. Third-party review of the FEED Study will be completed by Q1 2022, and model sensitivities will subsequently be run as needed, with FEED Study assumptions and inputs as appropriate. • Subject to finalization of rules by the Wyoming Public Service Commission (WPSC) to implement House Bill 200 (HB 200), the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), by March 31, 2022, PacifiCorp will file with the WPSC an initial CCUS application to establish intermediate CCUS standards and requirements. • Subject to finalization of rules by the WPSC to implement HB 200, the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), PacifiCorp will submit for WPSC approval a final plan with its proposed energy portfolio standard for dispatchable and reliable low-carbon electricity, its plan for achieving the standard, and a target date of no later than July 1, 2030.	be compared to outcomes in the 2023 IRP preferred portfolio. • Third parties reviewed the FEED Study in Q1 2022 and Q1 2023. Model sensitivities were completed in the 2023 IRP, with FEED Study assumptions and inputs as appropriate, and CCUS was not found to be economical. • PacifiCorp filed with the Wyoming Public Service Commission (WPSC) on March 31, 2022, an initial CCUS application to establish intermediate CCUS standards to implement House Bill 200 (HB 200). Additional information on this action item is included in the 2023 action plan.
1e	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the submission of second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the Environmental Protection Agency, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.	• States' submitted their state implementation plans for second planning period in 2022. Additional information on this action item is included in the 2023 action plan.

Action Item	2. New Resource Actions	Status
2a	**Customer Preference Request for Proposals:** • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2022, which may necessitate issuance of a request for proposals to procure resources within the action plan window..	PacifiCorp is in active discussions with the participating communities and anticipates filing an application for approval of the program with the Utah Public Service Commission in 2023.
2b	**Acquisition and Repowering of Foote Creek II-IV and Rock River I:** • In Q3 2021, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Foote Creek II-IV in order to issue repowering contracts in Q1 2022 in support of a late 2023 in-service date • In Q1 2022, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Rock River I following the expiration of the existing power purchase agreement in order to issue repowering contracts in Q3 2022 to support a late 2024 in-service date.	• In Q2 2022, the Wyoming Public Service Commission approved a CPCN for the project, and PacifiCorp acquired the Foote Creek II-IV facilities and began repowering construction activities. PacifiCorp will continue construction activities in 2023 to achieve a late 2023 in-service date. • In Q3 2022, the Wyoming Public Service Commission approved a CPCN for the project, and PacifiCorp acquired the project in Q1 2023. PacifiCorp will initiate construction activities in Q2 2023 to support a late 2024 in-service date.
2c	**Demonstration Project:** • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable.	• No required regulatory filings have been identified to date; PacifiCorp will continue to monitor

	• By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project. • Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders. • By 2027, PacifiCorp will begin training operators. • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.	• Negotiations on the final commercial agreement are ongoing • [Complete] • N/A • No required regulatory filings have been identified to date; PacifiCorp will continue to monitor
	<u>2022 All-Source Request for Proposals:</u> • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2026. • In September 2021, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In October 2021, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In January 2022, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q2 2022, PacifiCorp will identify an initial shortlist in advance of annual Cluster Request Window.	PacifiCorp filed a 2022 all source request for proposals (2022AS RFP) and received approval in three states by Q2 2022 in order to issue the solicitation to the market on April 29, 2022. PacifiCorp bid twelve eligible self-build (benchmark) resources on December 9, 2022, and on March 14, 2023, PacifiCorp received 302 bids from 74 developers and 93 different projects sites across six states. A final shortlist is expected by late Q2 2023 or early Q3 2023 with resources contracted by the end of Q4 2023.

	• In Q1 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q2 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. By Q4 2025-2026, winning bids from the all-source RFP are expected to achieve commercial operation. Resources must have commercial operation date of December 31, 2026, or earlier.	
2b	**2020 All-Source Request for Proposals:** • PacifiCorp filed for approval of the final shortlist in Oregon in June 2021. • In September 2021, PacifiCorp will file CPCN applications in Wyoming, as applicable, for final shortlist. • In Q4 2021, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. •	The 2020AS RFP has concluded with the procurement of 1,792 MW of wind, 495 MW of solar additions, and 697 200 MW of battery storage capacity, which was paired with the solar.

<table>
<tr><th>Action Item</th><th>3. Transmission Action Items</th><th>Status</th></tr>
<tr><td>3a</td><td><u>Energy Gateway South:</u>
By December 31, 2023, PacifiCorp will seek to build the approximately 400-mile, 500-kilovolt (kV) transmission line from the Aeolus substation near Medicine Bow, Wyoming to the Clover substation near Mona, Utah.
By Q2 2021, receive the final CPCN from the Wyoming Public Service Commission and the Public Service Commission of Utah (initial filing dates for the CPCN to be determined after stakeholder engagement).
By the end of Q4 2021, issue full notice to proceed to construct Energy Gateway South.
In Q4 2023, construction of Energy Gateway South is completed and placed in service.</td><td>Energy Gateway South has been moved to a target in-service date of Q4 2024.

This action item has been superseded by the Energy Gateway South Action in the 2023 action plan.</td></tr>
<tr><td>3b</td><td><u>Utah Valley Reinforcements:</u>
Utah Valley Reinforcements: As necessary to facilitate interconnection of customer-preference resources, PacifiCorp will proceed with system reinforcements in the Utah Valley.
In Q2 2020, complete the Spanish Fork 345 kV/138 kV transformer upgrade.
In Q4 2020, complete rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley.</td><td>In-service dates have been revised based on current project schedules as follows:
In Q1 2021, PacifiCorp completed the Spanish Fork 345 kV/138 kV transformer upgrade. The completion date for the transformer upgrade was shifted to 2021 due to outage constraints on the line. The remaining scope to complete improvements at a third-party owned substation was completed in Q2 2021.
In Q2 2021, PacifiCorp completed the rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley. The completion of this project shifted to 2021 due to delays in steel pole deliveries.</td></tr>
</table>

3c	<u>**Northern Utah Reinforcements:**</u> • Rebuild two miles of the Morton Court –Fifth West 138 kV line. • Loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond. • Complete identified plan of service supporting 2019 IRP preferred portfolio for resource additions in northern Utah.	The rebuild of two miles of the Morton Court –Third West 138 kV line is scheduled for Q2 2026. The project to loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond is now scheduled for Q4 2023.
3d	<u>**Utah South Reinforcements:**</u> • Develop plan of service in support of 2019 IRP preferred portfolio for resource additions in southern Utah. • Complete rebuild of the Mona –Clover #1 & #2 345 kV lines. • Identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah. •	In-service dates have been revised based on current project schedules. Washington action items are addressed in PacifiCorp's response to item 3e below. In Q3 2024 PacifiCorp is scheduled complete rebuild of the Mona –Clover #1 & #2 345 kV lines. In Q2 2026 PacifiCorp is scheduled to identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah.
3e	<u>**Yakima Washington Reinforcements:**</u> • To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in	The Vantage-Pomona Heights 230kV line was completed in August 2020.

	network upgrade requirements for generator interconnection requests. • In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process). • By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.	
3f	**<u>Boardman to Hemingway:</u>** • Continue to support the project under the conditions of the Boardman to Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue analysis in efforts to identify customer benefits that may include contributions to reliability, interconnection of additional resources, geographical diversity of intermittent resources, Energy Imbalance Market, and resource adequacy. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.	PacifiCorp filed for certificates of public convenience and necessity with the Idaho Public Utilities Commission and Wyoming Public Service Commission in Q1 2023. Also, in Q1 2023, Idaho Power and PacifiCorp signed a Joint Purchase and Sale agreement and PacifiCorp and Bonneville Power signed various service agreements as conditions of the Term Sheet between the parties.
3g	Energy Gateway West: • Energy Gateway West Segment D.2, continue construction with target in-service date of 12/31/2020. • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: For Segments D.3, and E, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. Also, continue to	Energy Gateway West Segment D.2 was completed in Q4 2020. The other action items remain on schedule. This action item has been superseded by the Energy Gateway West Action in the 2023 action plan.

<table>
<tr><td></td><td>support the projects by providing information and participating in public outreach.</td><td></td></tr>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th><th>Status</th></tr>
<tr><td>4a</td><td><u>Energy Efficiency and Demand Response Targets:</u>
• PacifiCorp will acquire cost-effective energy efficiency (Class 2 DSM) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp’s state-specific processes for planning for DSM acquisitions will be provided in Appendix D in Volume II of the 2021 IRP.
<table><tr><th>Year</th><th>Annual 1st Year Energy (GWh)</th><th>Annual Incremental Capacity (MW)</th></tr><tr><td>2021</td><td>510</td><td>157</td></tr><tr><td>2022</td><td>492</td><td>138</td></tr><tr><td>2023</td><td>486</td><td>144</td></tr><tr><td>2024</td><td>529</td><td>164</td></tr></table>* Note, Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.
• PacifiCorp will pursue cost-effective Class 1 (demand response) resources targeting annual system capacity selections from the preferred portfolio as summarized in Appendix D in Volume II of the 2021 IRP.
<table><tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr><tr><td>2021</td><td>0</td></tr><tr><td>2022</td><td>123</td></tr><tr><td>2023</td><td>242</td></tr><tr><td>2024</td><td>184</td></tr></table></td><td>Energy Efficiency Targets

2021 reporting indicates the company acquired 466GWh of energy efficiency system wide. This equates to 143 MW of capacity reductions.

Preliminary 2022 reporting indicates the company acquired 393 GWh of energy efficiency system wide. This equates to 110 MW of capacity reductions.

Coupling preliminary 2021 reporting with 2022 actuals, acquired 859 GWh of energy efficiency over the two years. This equates to capacity reductions of 253 MW (using the same GWh/MW relationship)

At the end of January 2021, PacifiCorp issued a demand response RFP to identify the potential acquisition of cost-effective flexible capacity. PacifiCorp procured and co-filed for new demand response resources following the completion of 2021 IRP. While not all MW volumes were not dispatched in 2022, the Company was able to have programs approved representing 171 MW of new DR resources since the 2021 IRP was published.</td></tr>
</table>

<table>
<tr><th>Action Item</th><th>5. Front Office Transactions</th><th>Status</th></tr>
<tr><td>5a</td><td><u>Market Purchases:</u>
Acquire short-term firm market purchases for on-peak delivery from 2019-2021 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.
Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.
Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.</td><td>Market purchases, inclusive of day-ahead, balance of month, prompt, and forward hedging transactions, but not accounting for any offsetting hedging sales, were made for on peak delivery in the following periods and at the following quantities:<table><tr><th>Year</th><th>Minimum MW</th><th>Maximum MW</th></tr><tr><td>2020</td><td>375</td><td>1,180</td></tr><tr><td>2021</td><td>550</td><td>2,179</td></tr><tr><td>2022</td><td>575</td><td>1,865</td></tr><tr><td>2023</td><td>125</td><td>1,870</td></tr></table>Market purchases are made in accordance with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices and include a mix of the transaction types identified in item 5a.</td></tr>
<tr><th>Action Item</th><th>6. Renewable Energy Credit Actions</th><th>Status</th></tr>
<tr><td>6a</td><td><u>Renewable Portfolio Standards (RPS):</u>
PacifiCorp will pursue unbundled RFPs to meet its state RPS compliance requirements.
As needed, issue RFPs seeking then current-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2020. As needed, issue RFPs seeking</td><td>PacifiCorp continues to evaluate the need for unbundled RECs and will issue RFPs to meet its state RPS compliance requirements as needed in California. Most recently, PacifiCorp issued an RFP for RECs to meet California RPS compliance requirements.</td></tr>
</table>

	then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington RPS targets.	
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp issued reverse RFPs in April 2019, March 2020, February 2021, October 2021, and September 2022. PacifiCorp will continue to engage in bilateral REC sales and issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the 2023 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis including load, private generation, changes in available resources, and emissions polices. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2023 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources qualifying for federal income tax credits, market purchases, and energy efficiency and demand response resources are consistently selected. Further, the procurement processes associated with these resource actions are well underway. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2023 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, CO_2 policy also influences resource selections in the 2023 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event, PacifiCorp identifies the planning scenario assumption affecting both short-term (2023-2032) and long-term (2032-2040) resource strategies.

Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[1] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability and flexibility at a reasonable cost. summarizes PacifiCorp's 2023 IRP acquisition path analysis, which provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

[1] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

Table 10.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
Higher sustained load growth	High economic drivers accounting for 95% prediction interval and low private generation assumption.	• In 2028, there is an increase of 2 percent higher sustained load growth than the base case forecast, resulting in an increase in peak capacity requirements of 271 MW increasing further to nearly 337 MW in 2032. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades • The higher peak capacity requirements relative to the base case forecast results in additional resource need, increased market reliance and/or shifts in timing of planned resources or coal unit retirements. • As the higher load is distributed over multiple load areas and across years, additional battery, solar and wind resources in combination will meet the higher demand.	• In 2042, there is an increase of 4 percent higher sustained load growth than the base case forecast, resulting in an increase in peak capacity requirements of 616 MW. • The higher peak capacity requirements relative to the base case forecast results in additional resource need, increased market reliance and/or shifts in timing of planned resources or coal unit retirements. • As the higher load is distributed over multiple load areas and across years, additional battery, solar and wind resources in combination will meet the higher demand.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
Lower sustained load growth	Low economic drivers accounting for 95% prediction interval and high private generation assumption.	• In 2028, there is 2 percent lower sustained load growth than the base case forecast, resulting in a decrease in peak capacity requirements of 256 MW decreasing further 288 MW in 2032. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • The lower peak capacity requirements relative to the base case forecast results in a reduction in resource need, decreased market reliance and/or shifts in timing of planned resources or coal unit retirements.	• In 2042, there is a 2 percent lower sustained load growth than the base case forecast, resulting in a decrease in peak capacity requirements of 363 MW. • The lower peak capacity requirements relative to the base case forecast results in a reduction in resource need, decreased market reliance and/or shifts in timing of planned resources or coal unit retirements.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
Higher sustained private generation penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• In 2028, peak capacity requirements are lower by 29 MW due to higher sustained private generation levels relative to the base case forecast. • In 2032, peak capacity requirements are lower by 63 MW due to higher sustained private generation levels relative to the base case forecast. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy.	• In 2042, peak capacity requirements are lower by 102 MW due to higher sustained private generation levels relative to the base case forecast. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy. • Timing differences in resource capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
Lower sustained private generation penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• In 2028, peak capacity requirements are higher by 44 MW due to lower sustained private generation levels relative to the base case forecast. • In 2032, peak capacity requirements are higher by 97 MW due to lower sustained private generation levels relative to the base case forecast. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy.	• In 2042, peak capacity requirements are higher by 293 MW due to lower sustained private generation levels relative to the base case forecast. • Timing differences in resource capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
High CO_2 prices with accelerated coal retirements	Fossil-fired generation is faced with a high CO_2 price beginning in 2025 at $4434/ton and reaching $132.70/ton by 2042 that drives all coal to be retired by 2030 (?)	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Accelerate timing of new resource additions including an advanced nuclear resource from 2033 to 2032. • By 2030 the portfolio swaps 600 MW of four hour battery for 600 MW of long duration storage and adds 790 MW of additional Solar resources. • Wind selections are slightly reduced until 2032, at which time the model adds a total of 3,714 MW incremental wind compared to the preferred portfolio. • Increase procurement of market purchases. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases 81 MW by 2032.	• By 2042, new nuclear peaking capacity is increased by 500 MW. • By 2042, DSM (energy efficiency and demand response combined) is increased by 366 MW and standalone storage capacity is increased by over 1,000 MW.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
No Natrium™ Advanced Nuclear Demonstration Project in 2030, and no other nuclear projects	See Volume 1, Chapter 9 (Modeling and Portfolio Selection Results), P05-No NUC portfolio	• Without the Natrium™ demonstration project, 289 MW of non-emitting peaking resource is added in 2030. • In 2032 the second advanced nuclear plant is replaced by 303 MW of non-emitting peaking resource and 200 MW of four-hour battery storage. • Higher costs and emissions result from increased fossil-fueled generation, emissions and net market transactions.	• In 2033, 303 MW of non-emitting peaking resources and 200 MW of four-hour battery storage replace 500 MW of nuclear capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
No Boardman-to-Hemingway (B2H) transmission segment in 2026	See Volume 1, Chapter 9 (Modeling and Portfolio Selection Results), P02b-No B2H portfolio	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Without B2H, 724 MW of standalone storage is built in 2027 as a requirement of not building the B2H line. • 300 MW of solar is removed from the portfolio in 2028, and 400 MW of wind shifts from Borah Populous in 2028 to Southern Oregon in 2029. • An additional 600 MW of storage is moved from Borah Populous to Southern Oregon in 2028. • 400 MW of wind is accelerated from 2033 into 2030. A reduction in resources results in increased reliance on the market and higher emissions from an increase in coal and gas generation. • Reduced flexibility and load-serving capability of the transmission system.	• An additional 600 MW of solar and 600 MW of storage is built in Southern Oregon in 2033.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
New Load	Incremental 3,000 MW of flat load entering the system in 2033	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades.	• Resources required to serve load – 2,000 MW wind, 1,600 MW solar, 1,600 MNW battery, and 881 MW non-emitting peaker. • Requires Boardman to Hemingway 2, Gateway South 2, D3.2 transmission line, Gateway Segment E and Gateway Segment E 2.

Procurement Delays

The main procurement risk is an inability to procure resources in the required timeframe to meet the least-cost, least-risk mix of resources identified in the preferred portfolio. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in a given action plan period. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all of the capacity needs.
- Temporarily drop below its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

The 2023 IRP includes a sensitivity that complies with the Utah requirement to perform a business plan sensitivity case consistent with the commission's order in Docket No. 15-035-04. This order sets forth the following parameters for this sensitivity case:

- Over the first three years, resources align with those assumed in PacifiCorp's December 2022 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

PacifiCorp will file a supplemental filing to its 2023 IRP filing that includes discussion and results of the sensitivities outlined in Volume I, Chapter 9 (Modeling and Portfolio Selection Results), including a discussion of this business plan sensitivity case summarizing portfolio differences between the business plan sensitivity case and the 2023 IRP preferred portfolio. This study will capture changes to the resource mix, present value revenue requirement of system costs, and implications on the near-term action plan. The supplemental filing will also be posted to PacifiCorp's IRP webpage at the following location: www.pacificorp.com/energy/integrated-resource-plan.

Resource Procurement Strategy

To acquire resources outlined in the 2023 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide economic benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs such as load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2023 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use a competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-Side Management[2]

PacifiCorp offers a robust portfolio of demand response and energy efficiency programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp provides Class 4 DSM offerings, and has continued ***watt***smart outreach and communications. Educating customers regarding energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will continue to evaluate how to best incorporate potential DSM programs into the broader all-source RFP process discussed above or whether separate RFPs focused on these resources are warranted based on state-specific requirements and program needs.

Small Scale Renewable Energy Supply

In order to fulfil Oregon regulatory requirements for small-scale renewable resources, PacifiCorp plans to issue a small-scale renewable energy RFP in 2024 to solicit resources within its territory which are 20 MW or smaller and can be commercially operational by 2028. Currently, Oregon's new HB 2021 legislation and associated Clean Energy Plan is driving a specific evaluation of small-scale renewables that may help to identify the costs and benefits of smaller (20 MW or less installed capacity) community-owned renewables projects across PacifiCorp's service territory. This study is addressed in PacifiCorp's 2023 Oregon Clean Energy Plan.

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time.

[2] Class 1 DSM is most commonly referred to as "demand response" in the 2023 IRP; Class 2 DSM is most commonly referred to as "energy efficiency". Class 4 DSM describes energy efficiency measures achieved through public outreach and education.

Alternately and depending on contractual terms, purchasing power from a third party in a long-term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power-purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Power-purchase agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation may affect PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives.

As evident in the 2023 IRP, known and prospective environmental regulations, such as the Ozone Transport Rule (OTR) and Inflation Reduction Act (IRA), can impact utilization of resources and investment decisions. Both of these federal government directed changes require further definition. For the OTR, a final decision regarding the timing of Wyoming's participation remains in flux. For the IRA, which exceeds 700 pages, there has been insufficient time for this comprehensive legislation to be digested fully in resource planning. PacifiCorp's 20230 IRP captures those components which are best understood and most appropriate to the IRP's scope, including impacts on production tax credits and investment tax credits for non-emitting resources. Of key interest will be the U.S. Treasury Department's implementation of the IRA's clean energy tax credit provisions, which will address the allocation of bonus credits, the eligibility of certain credits to certain technologies, and other key issues.

Compliance strategies will be affected by how and whether states or the federal government choose to implement further policies related to greenhouse gases and nitrogen oxide. State or federal frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a CO_2 tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as CO_2 capture with sequestration. As mentioned above, plant CO_2 emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; (2) reduce volatility of net power costs for PacifiCorp's customers. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market changes. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the president of Pacific Power, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within power volume hedge limits and natural gas percent hedge volume limits.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long-run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take

contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total generation capacity relative to customer load requirements at a given point in time.

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise.

Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continues to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2023 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.