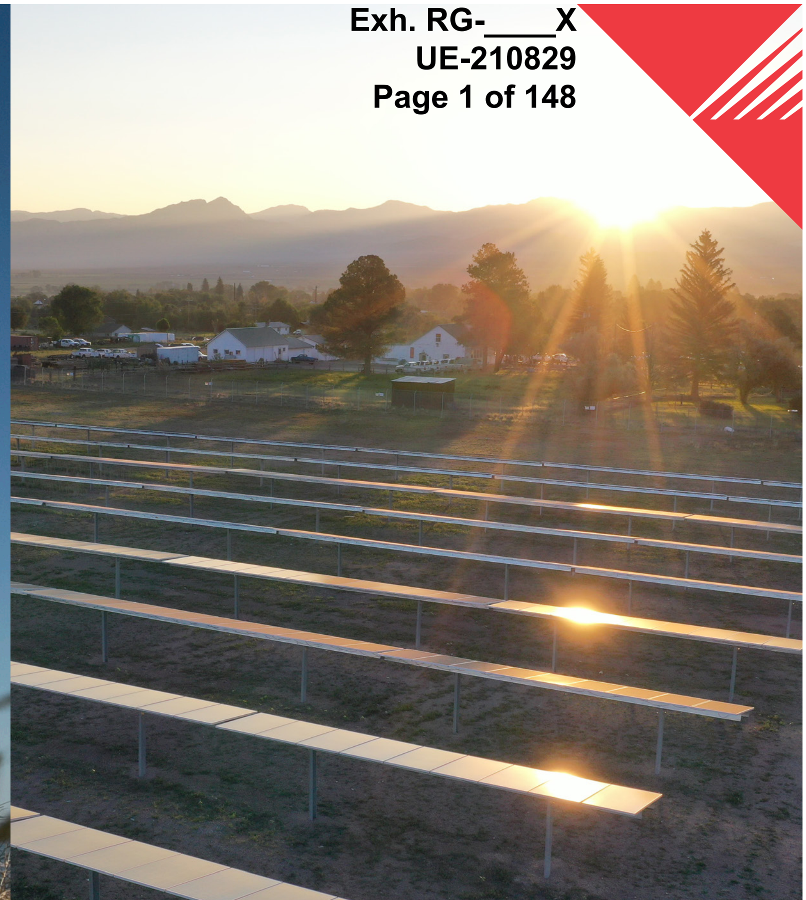

2023 Integrated Resource Plan Update

April 1, 2024

PACIFICORP

This 2023 Integrated Resource Plan Update is based upon the best available information at the time of preparation. The IRP action plan status update described herein 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.

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PacifiCorp submitted its Amended Final 2023 Integrated Resource Plan (IRP) on May 31, 2023. That plan provides a framework for future actions PacifiCorp will take to provide reliable and valuable electric service for customers with a least-cost, least-risk resource portfolio. The 2023 IRP Update reflects resource planning and procurement activities since the 2023 IRP, presents an updated load-and-resource balance, and an updated resource portfolio consistent with changes in the planning environment. The 2023 IRP Update also provides a status update for the action plan filed with the 2023 IRP. In presenting the updated load-and-resource balance and updated resource portfolio, PacifiCorp highlights changes in the 2023 IRP Update preferred portfolio[1] relative to the 2023 IRP preferred portfolio, which covers the 2024 to 2042 planning horizon. Consistent with the 2023 IRP, the 2023 IRP Update's preferred portfolio demonstrates reliable service will require investment in transmission infrastructure, new wind and solar resources, the conversion of two coal units to natural gas peaking units, growth in demand response and energy efficiency programs, the addition of carbon capture technology on identified coal resources, the addition of an advanced nuclear resource, the addition of energy storage resources, and the addition of natural gas peaking resources that are capable of converting to non-emitting fuels. The 2023 IRP Update preferred portfolio includes resources necessary for individual state policy compliance and assumes those resources are allocated to the state whose policy necessitated the addition.

Key changes in this 2023 IRP Update are driven by U.S. Environmental Protection Agency's (EPA) approval of Wyoming's state Ozone Transport Rule (OTR) plan, the stay of EPA's disapproval of Utah's state OTR plan, extensions to the assumed operational life of new natural gas generating resources, energy storage acquisition strategy, forecast load demand, higher coal prices, and natural gas and wholesale power market price updates.

In addition, PacifiCorp has advanced its modeling strategy to address regulatory and stakeholder feedback, using a robust iterative process to refine the optimization process. For example, the 2023 IRP Update preferred portfolio includes system-allocated resources as well as resources that are needed to meet the requirements of specific states. Resources needed to meet specific state policy compliance requirements may need to be assigned, in their entirety, to a single state to avoid adding unnecessary cost burdens to customers in other states, which could raise other potential issues related to operations and resource adequacy that have not been addressed in the system approach of the 2023 IRP Update preferred portfolio. Future allocations of any incremental costs associated with both system resources and resources included in the plan solely to meet state-specific policy objectives will need to be addressed to ensure alignment of costs and benefits.

Customer Focus

At PacifiCorp, we're committed to meeting the demands of our customers and communities throughout the West to deliver safe, affordable, reliable energy and a resilient, modern grid. Our integrated system connects and brings new opportunities to the West, building on a foundation of infrastructure designed to handle extreme weather and enhance the energy resilience of communities from the Pacific Coast to the Rocky Mountains, all while continuing to deliver valuable energy solutions for our customers at prices that are below national and regional averages.

[1] The preferred portfolio is the least-cost, least-risk resource plan over the 20-year IRP study horizon.

Together with the communities we serve and our regional partners, it is time to act, with targeted, strategic investments that will position us to continue delivering safe, valuable, reliable power to our customers.

Our customer-centered vision embodies four core themes:

Reliable Power: We strive to deliver energy safely during all hours, and plan extensively to ensure that we have sufficient supply and the ability to deliver to the communities we serve. We understand that electricity is an essential service, and work around the clock to ensure that we are dependable, and that our communities can rely on us.

Resilient Infrastructure: We live in times of rapid change, with more extreme weather and challenging conditions. We are working to minimize disruptions, implement strategies to recover quickly when they occur, and deploy upgrades that will strengthen our critical infrastructure.

Valuable Service: PacifiCorp is proud to be one of the lowest-cost electricity providers in the nation and the region and we are committed to continue doing so as we make new and much needed investments in generation and transmission infrastructure. As we plan for new resources, we are prioritizing actions that are necessary to support customer needs and the reliability of the system while reflecting the policy values of each of our states at the lowest cost possible.

Clean Energy: Through strategic, customer-focused investments in diverse resources, PacifiCorp's plan continues to show a reduction in carbon emissions. The 2023 IRP Update preferred portfolio indicates that carbon emissions will decrease by more than 60% from 2005 levels by 2030. Although a higher load forecast and the removal of OTR compliance requirements has extended our emissions reduction timeline in comparison to the 2023 IRP, the 2023 IRP Update resource plan continues to include significant new renewable additions among other diverse, advanced technologies. This path of renewables additions and advanced technologies achieves even deeper decarbonization beyond 2030.

2023 IRP Update Roadmap

We're advancing our critical infrastructure to meet the challenges of a rapidly changing economy, while laying the groundwork for long-term value and reliability through building a more resilient grid.

The 2023 IRP Update preferred portfolio includes:

- Resources
  - 9,818 megawatts of new wind resources (including 443 megawatts for Washington and 239 megawatts of small-sale wind for Oregon).
  - 4,016 megawatts of storage resources, including batteries collocated with solar generation, standalone batteries, and pumped hydro storage resources (including 101 megawatts of standalone batteries for Oregon and Washington).

- 3,763 megawatts of new solar resources, mostly paired with battery storage, (including 483 megawatts of small-scale solar for Oregon).
- 4,326 megawatts of capacity saved through energy efficiency programs.
- 1,123 megawatts of capacity saved through demand response programs.
- 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project) in 2030.
- 5,385 megawatts of natural gas convertible peaking resources that meet high-demand energy needs (including 224 megawatts of renewable-fueled peaking resources for Oregon).
- Installation of carbon capture technology on Jim Bridger Units 3 and 4.

- Transmission
  - As supported by needs established in previous IRPs, PacifiCorp is finalizing construction of the Energy Gateway South and Energy Gateway West Sub-Segment D1 transmission projects and partnering with Idaho Power to build the Energy Gateway Sub-Segment H (Boardman-to-Hemingway or B2H) transmission project.
  - Additional transmission upgrades to increase transfer capability and/or enable renewable resource requests to connect to the transmission system in southeast Idaho, central and northern Utah, eastern Wyoming, throughout Oregon, and in Yakima and Walla Walla, Washington. Approximately two gigawatts of additional interconnection capacity are added through 2032, in addition to the amounts directly associated with Energy Gateway South, Energy Gateway West Sub-Segment D1, and B2H.

PacifiCorp's Integrated Resource Plan Approach

In the 2023 IRP Update, PacifiCorp presents a preferred portfolio that builds on its vision to deliver valuable energy service, reliably, and responsibly. We are achieving this vision while meeting our customers' growing energy needs through near-term investments in transmission infrastructure and continued growth in new generation and storage resource capacity as well as maintaining substantial investment in energy efficiency and demand response programs.

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 delivering reliable service to customers and ensuring compliance with state and federal regulatory obligations without cost-shifting amongst states for compliance.

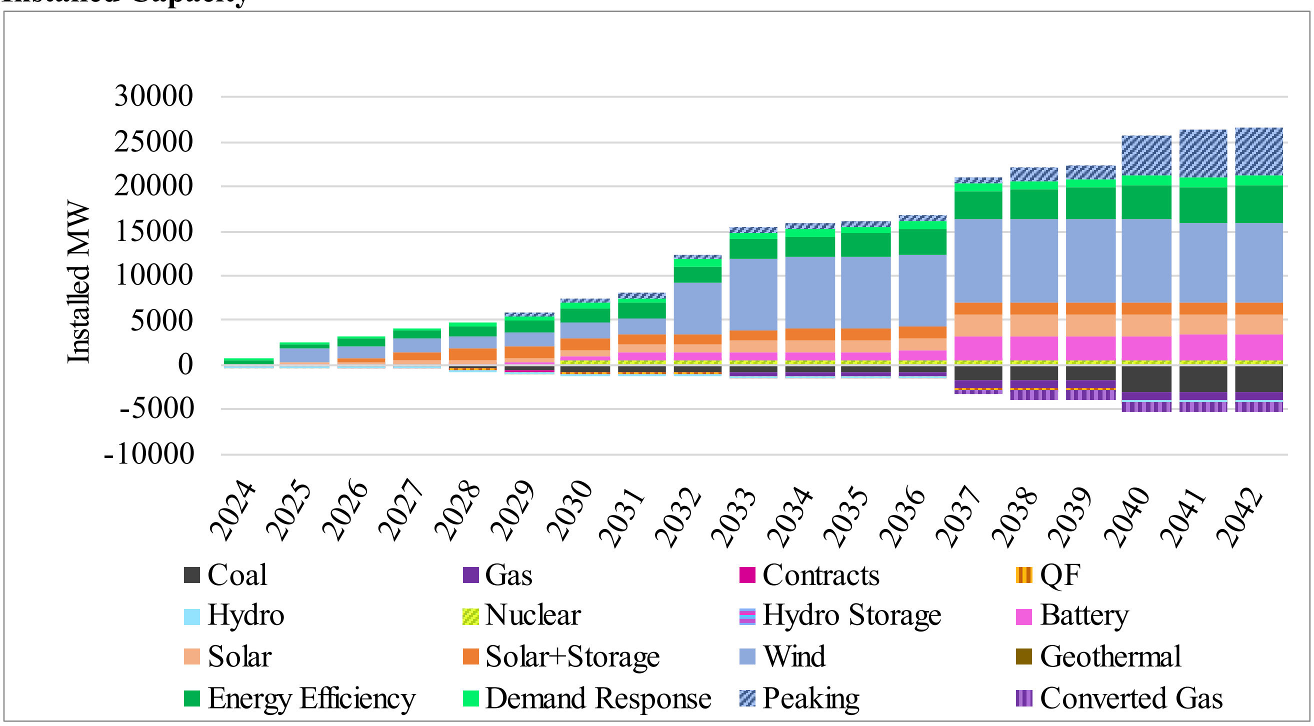
The full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly the longer-range elements, can and do change over time.

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

2023 IRP Update Preferred Portfolio Highlights

PacifiCorp's selection of the 2023 IRP Update preferred portfolio is supported by comprehensive data analysis, described in the chapters that follow. Figure 1.2 shows that PacifiCorp's 2023 IRP Update preferred portfolio continues to include substantial new renewables facilitated by incremental transmission investments, along with demand-side management (DSM) resources, significant storage resources, Natrium™ advanced nuclear, and dispatchable peaking resources. A more detailed summary of preferred portfolio resources by resource type is presented later in this section.

Figure 1.2 – 2023 IRP Update All-State Preferred Portfolio Cumulative Changes in Installed Capacity



*Note: "Coal" includes both minority and majority owned coal resources, including Jim Bridgers 3 & 4 with carbon capture technology. "Coal" does not include coal resources converted to gas. Coal resources converted to gas are categorized under "Converted Gas" and are only shown at retirement, as the conversion does not increase the installed capacity of the resource. "Gas" includes only existing gas resources. New gas peaking and new hydrogen peaking resources are grouped under "Peaking". "Nuclear" includes only the Natrium™ advanced nuclear project.

Transmission Upgrades

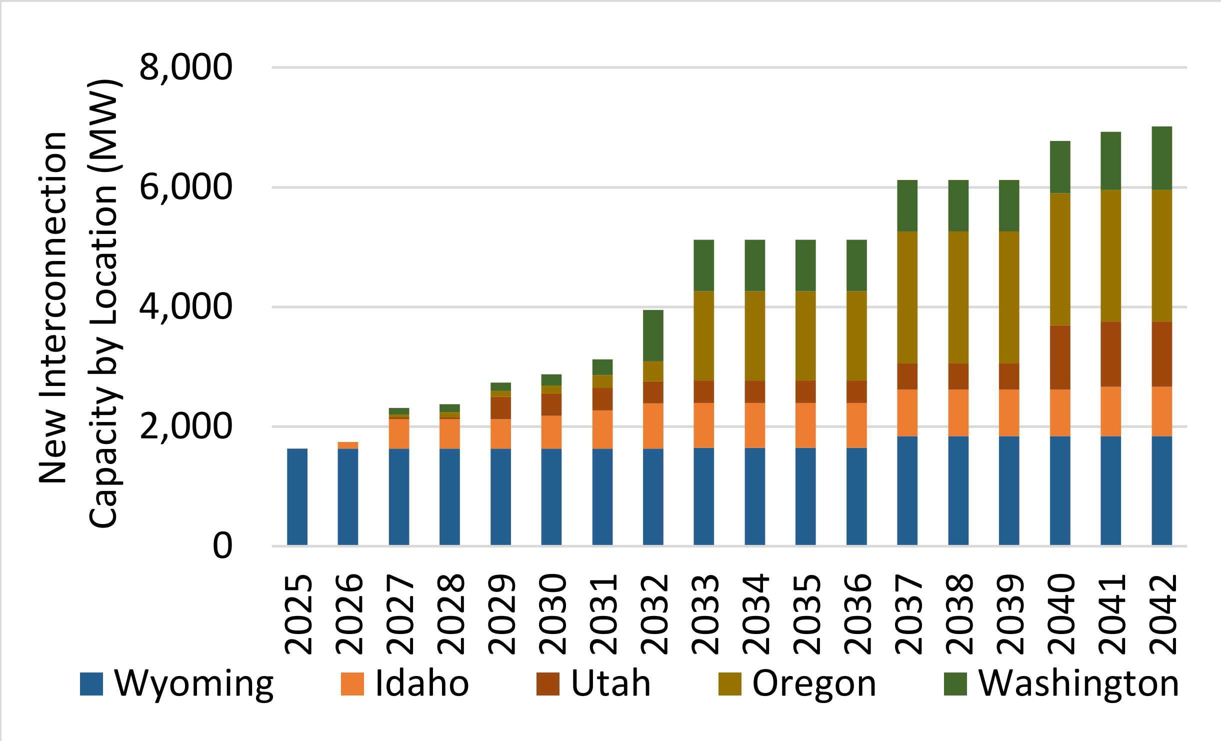
To facilitate the delivery of new resources to PacifiCorp customers across the West, the 2023 IRP Update preferred portfolio includes additional transmission investment. As supported by needs established in previous IRPs, PacifiCorp is finalizing construction of the Energy Gateway South and Energy Gateway West Sub-Segment D1 transmission projects and partnering with Idaho Power to build the B2H transmission project, which is expected to come online in the 2026-2027 timeframe. B2H is a 290-mile high-voltage 500 kilovolt transmission line that connects the Longhorn substation near the town of Boardman in Oregon to the Hemingway substation in Idaho. 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.

In the 2023 IRP Update, many transmission upgrades and the accompanying resources reflect the results of PacifiCorp's generator interconnection "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, transmission upgrades and resource additions in the 2023 IRP Update preferred portfolio consider cluster study requests submitted in the past several years. Figure 1.3 summarizes the new interconnection capacity selected to facilitate new generation resources identified as part of the 2023 IRP Update preferred portfolio.

In addition to providing increased interconnection capacity, transmission upgrades are also expected to allow for increased transfer capability between different areas of PacifiCorp's system. The 2023 IRP Update preferred portfolio includes portions of the following transmission upgrades between the following areas within the IRP topology. Note that modeling for the 2023 IRP Update allowed for partial selection of lines, though that does not indicate that these lines would be uneconomic if built in their entirety. Given the timing identified primarily in the second half of the IRP study horizon, these opportunities will continue to be explored in the future.

- Walla Walla to Yakima.
- Gateway Sub-Segment D3: provides direct transfers between Jim Bridger and Borah (Populus), but with supporting projects, also facilitates transfers between Wyoming East and Jim Bridger and between Borah and Utah North.
- Incremental Gateway Segments: Segments D2.2, D1.2, and Gateway South 2 would be the second iteration of existing or soon to be in service segments from the original Gateway plan, and would provide additional transfer capability between Wyoming East and Bridger and between Wyoming East and Clover.
- Oregon 500 kilovolt upgrades: several 500 kilovolt upgrades and supporting projects would connect Portland-North Coast, Willamette Valley, Southern Oregon, and Central Oregon.
- East-West transfers: together, B2H 2 and Gateway Segment E would further increase transfer capability between PacifiCorp's east and west balancing authority areas.

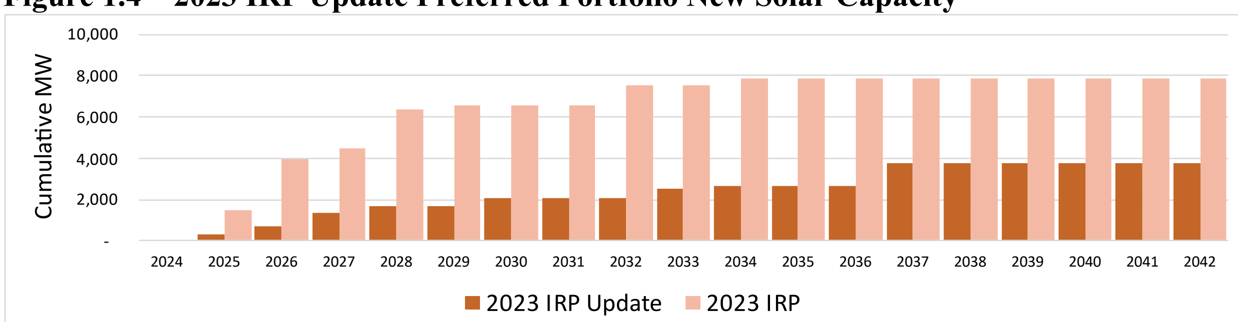
Figure 1.3 – New Interconnection Capacity by Location



New Solar Resources

The 2023 IRP Update preferred portfolio includes 2,084 megawatts of solar by the end of 2030, and 3,749 megawatts of new solar is online by 2037, as shown in Figure 1.4 While not shown in Figure 1.4, the company has previously contracted for one gigawatt of solar resources with commercial operation dates between 2024 and 2026 for customer-directed voluntary renewable procurement programs.

Figure 1.4 – 2023 IRP Update Preferred Portfolio New Solar Capacity*

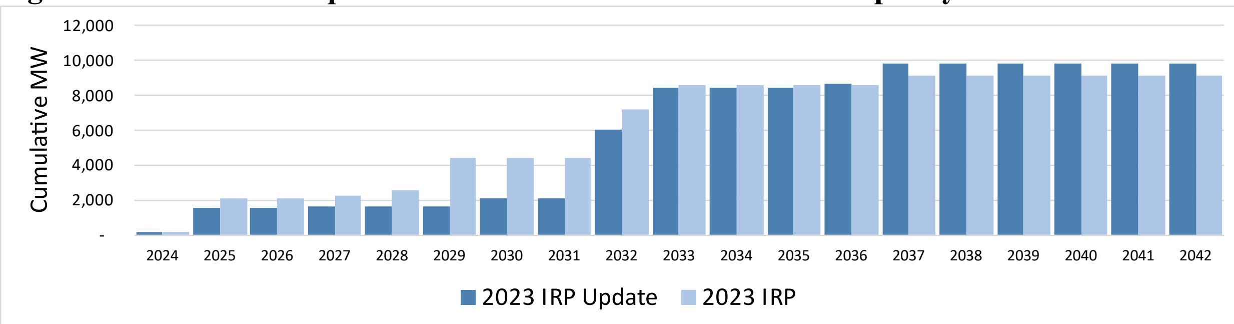


* 2023 IRP Update solar capacity shown in the figure includes committed solar resources shown in 2025 and 2026. Resources are shown in the first full year of operation (the year after the year-online dates). This total includes 374 megawatts of small scale solar to meet Oregon requirements.

New Wind Resources

As shown in Figure 1.5, by 2032, PacifiCorp's 2023 IRP Update preferred portfolio includes 6,034 megawatts of new wind resources, and more than 9,800 megawatts of new wind resources by 2037.

Figure 1.5 – 2023 IRP Update Preferred Portfolio New Wind Capacity*

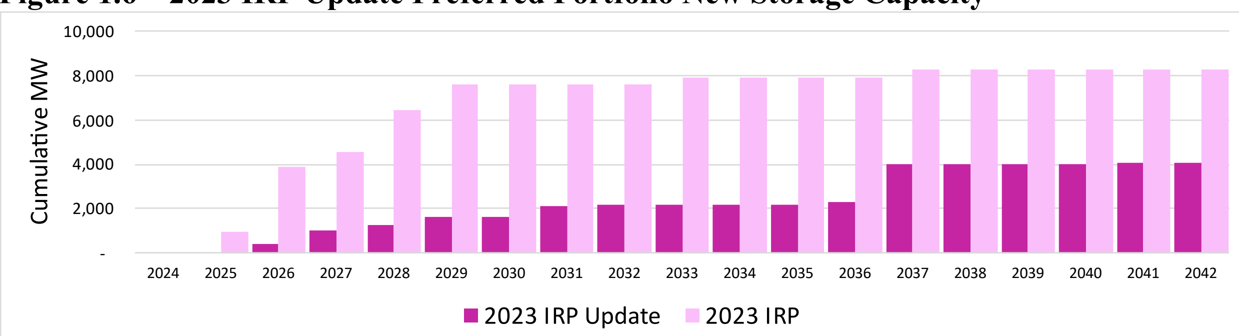


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates). This figure includes 254 megawatts of small-scale wind to meet Oregon requirements, and an additional 443 megawatts of utility scale wind to meet Washington requirements.

New Storage Resources

As shown in Figure 1.6, the 2023 IRP Update preferred portfolio includes 1,626 megawatts of new storage capacity by the end of year 2029 and more than 4,000 megawatts by 2037.

Figure 1.6 – 2023 IRP Update Preferred Portfolio New Storage Capacity*

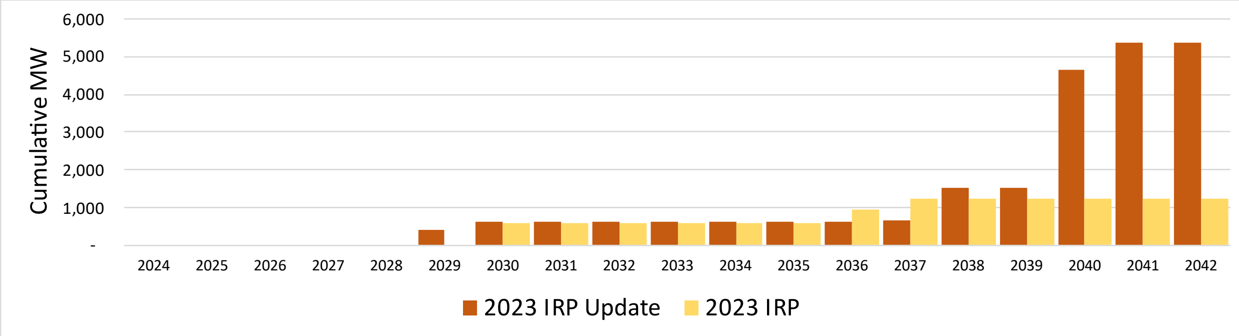


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates). This figure includes a total of 101 megawatts of storage resources required for Oregon and Washington for compliance.

Peaking Capacity

The 2023 IRP Update continues to indicate the need for flexible peaking capacity to achieve reliability and minimize risk. A key change since the filing of the 2023 IRP is the addition of peaking capacity in the form of natural gas resources capable of operating with 100% hydrogen fuel. The inclusion of this technology also guards against the future risk of increasingly constrained emissions and future policy requirements.

Figure 1.7 – 2023 IRP Update Preferred Portfolio Peaking Resources Capacity*

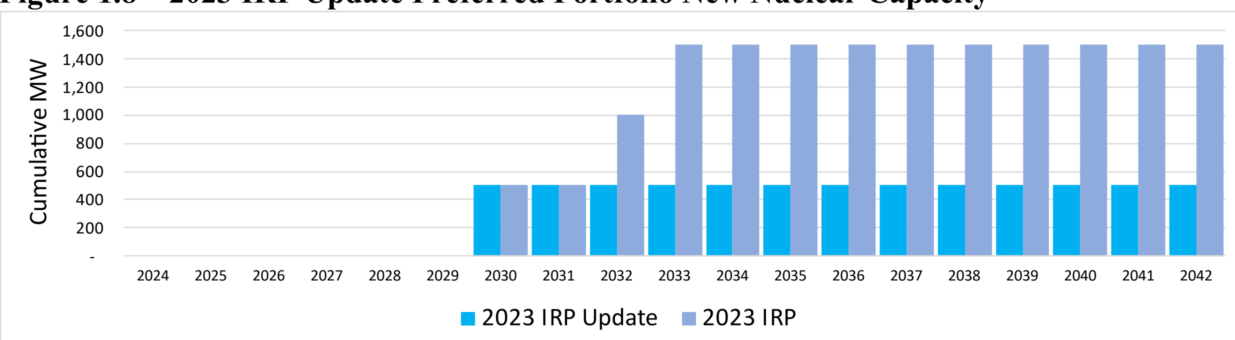


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates). This figure includes 224 megawatts of peaking units for Oregon compliance that can only run on renewable fuel.

Nuclear Capacity

The 2023 IRP Update continues to show the value associated with the Natrium™ Demonstration Project which provides a significant non-emitting resource. A key change since the filing of the 2023 IRP is the stay of the EPA's disapproval of Utah's OTR plan and subsequent ability of the existing thermal fleet to operate with fewer restrictions as a dispatchable resource. Although additional advanced nuclear resources beyond the Natrium™ Demonstration Project are not selected in this update, PacifiCorp is continually updating advanced nuclear resource cost estimates as they become available.

Figure 1.8 – 2023 IRP Update Preferred Portfolio New Nuclear 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. The optimal determination of DSM resources results in selecting all cost-effective DSM as a core function of IRP modeling. 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 Update.

Figure 1.9 indicates that PacifiCorp's load forecast before incremental energy efficiency savings has decreased over the 2024 to 2027 timeframe and increased from 2028 and on relative to projected loads used in the 2023 IRP. In the near term, lower projected demand from data centers results in a lower forecast, while data center expectations over the long-term result in a higher forecast. On average, the forecasted system load is up 0.8% and the forecasted coincident system peak is up 1.2% over the 20-year planning horizon when compared to the 2023 IRP. Over the 2024 to 2042 timeframe, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.13% for load and 1.80% for peak.

Figure 1.9 – Forecasted Annual Load (Before Incremental Energy Efficiency Savings)

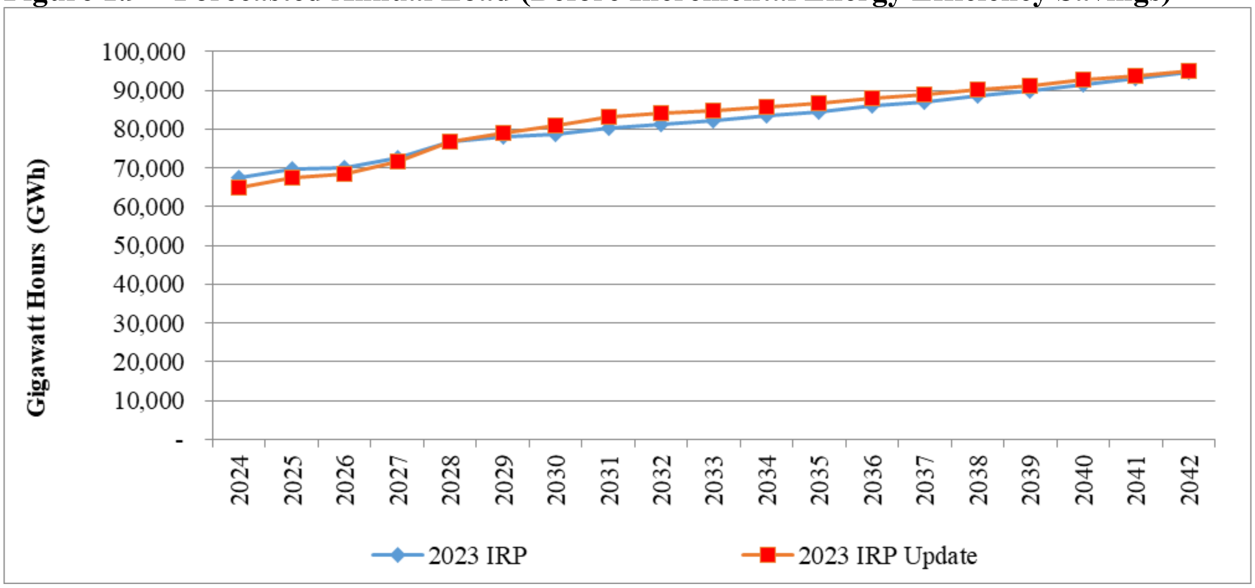
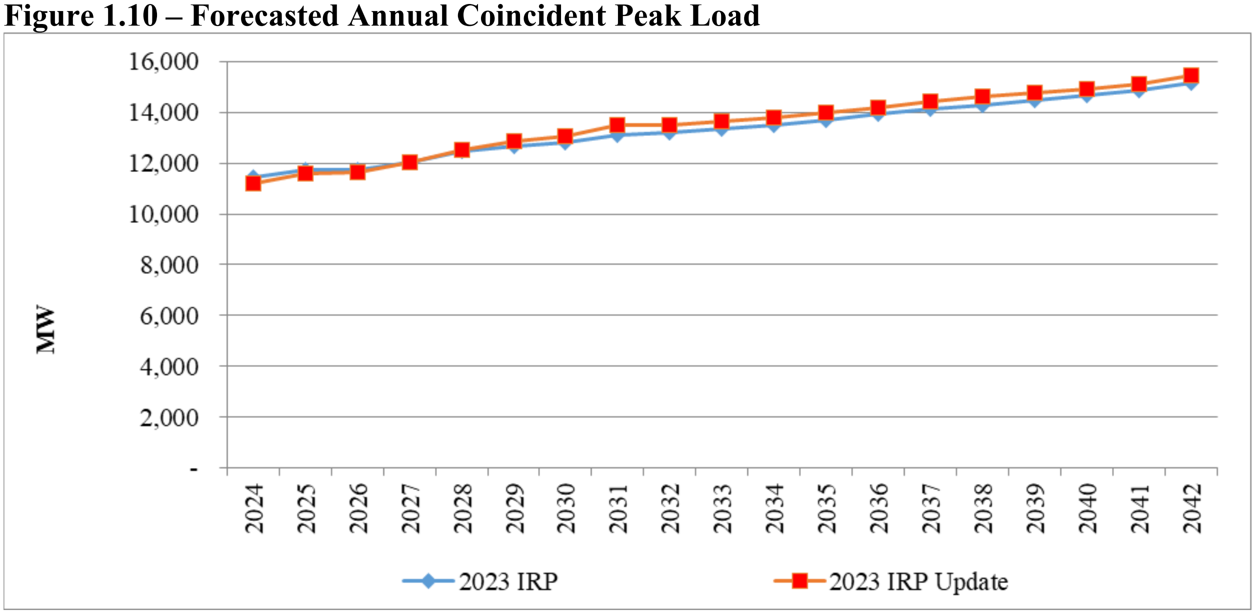


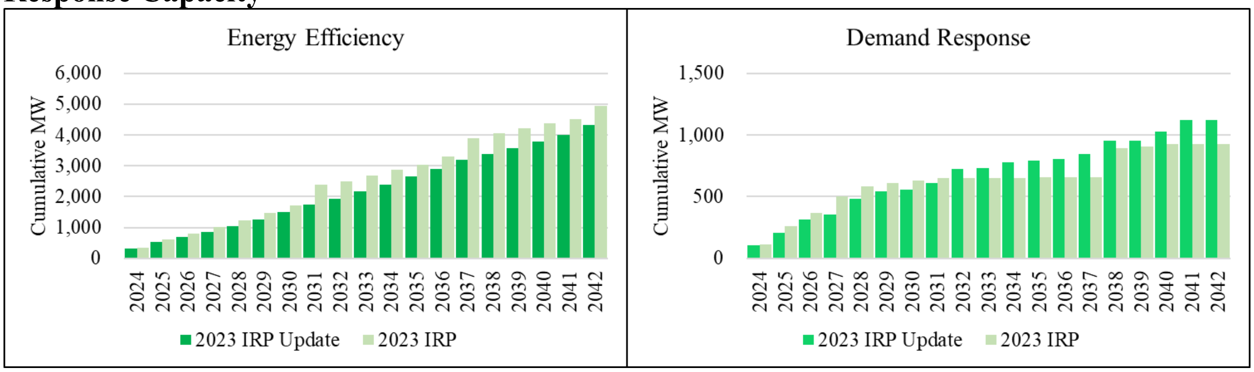
Figure 1.10 – Forecasted Annual Coincident Peak Load



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 1.11 compares total energy efficiency capacity savings in the 2023 IRP Update preferred portfolio relative to the 2023 IRP preferred portfolio and includes 4,326 megawatts 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 1.11 compares cumulative demand response program capacity in the 2023 IRP Update preferred portfolio relative to the 2023 IRP preferred portfolio and does not include capacity from existing programs. The 2023 IRP Update has a cumulative capacity of incremental demand response programs reaching 1,123 megawatts by 2042 which represents a 21% increase relative to the 2023 IRP.

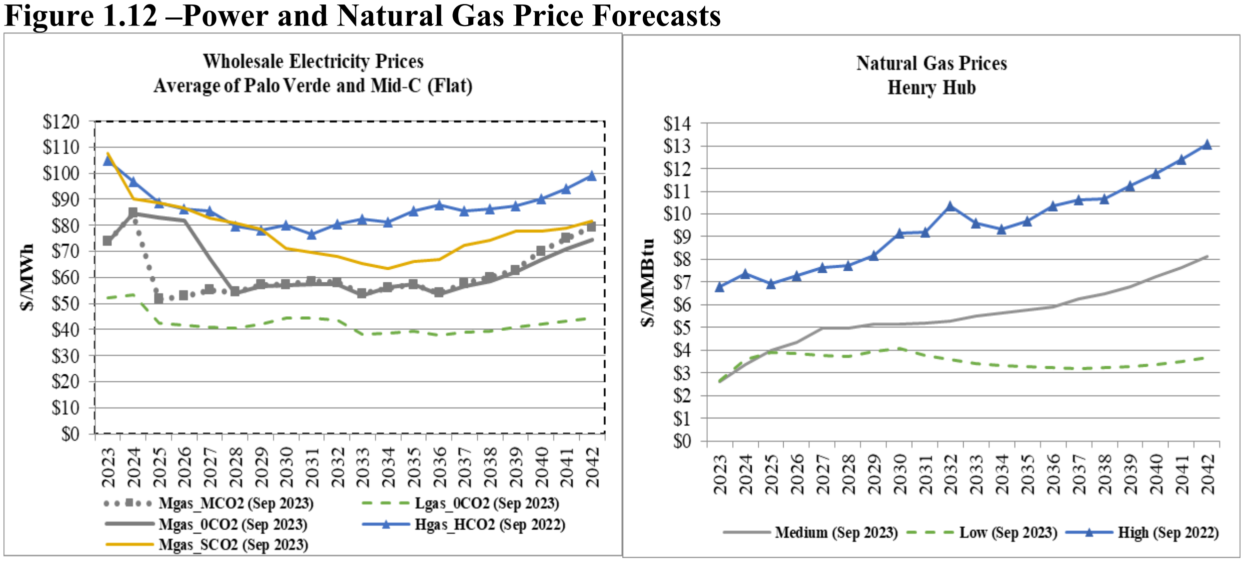
Figure 1.11 – 2023 IRP Update Preferred Portfolio Energy Efficiency and Demand Response Capacity



Wholesale Power Market Prices and Market Activity

Figure 1.12 illustrates the electricity and natural gas price forecasts used in the 2023 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

Figure 1.12 –Power and Natural Gas Price Forecasts



Subsequent to the filing of the 2023 IRP, the EPA's approval of Wyoming's state OTR plan and the stay of EPA's disapproval of Utah's state OTR plan removed the restrictions that limit energy production in the summer from natural gas and coal-fueled resources in Wyoming and Utah. In the absence of the OTR driver, market purchases can cost-effectively replace some of the incremental renewable resources that were indicated in the 2023 IRP preferred portfolio, leading to higher relative market activity, as shown in Figure 1.13 and Figure 1.14 below. In addition, a 500 megawatt capacity Wyoming market has been added in the 2023 IRP update, representing the ongoing ability to access diverse (and potentially new) regional markets as discussed in Chapter 3.

Figure 1.13 – 2023 IRP Update Preferred Portfolio Summer Market Purchases

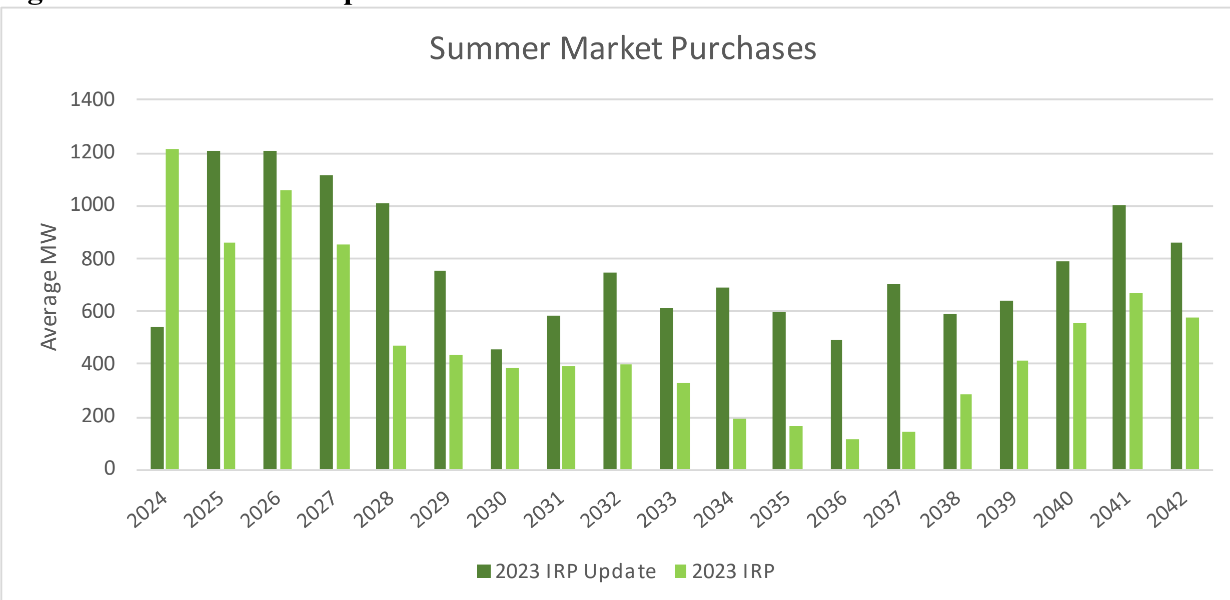
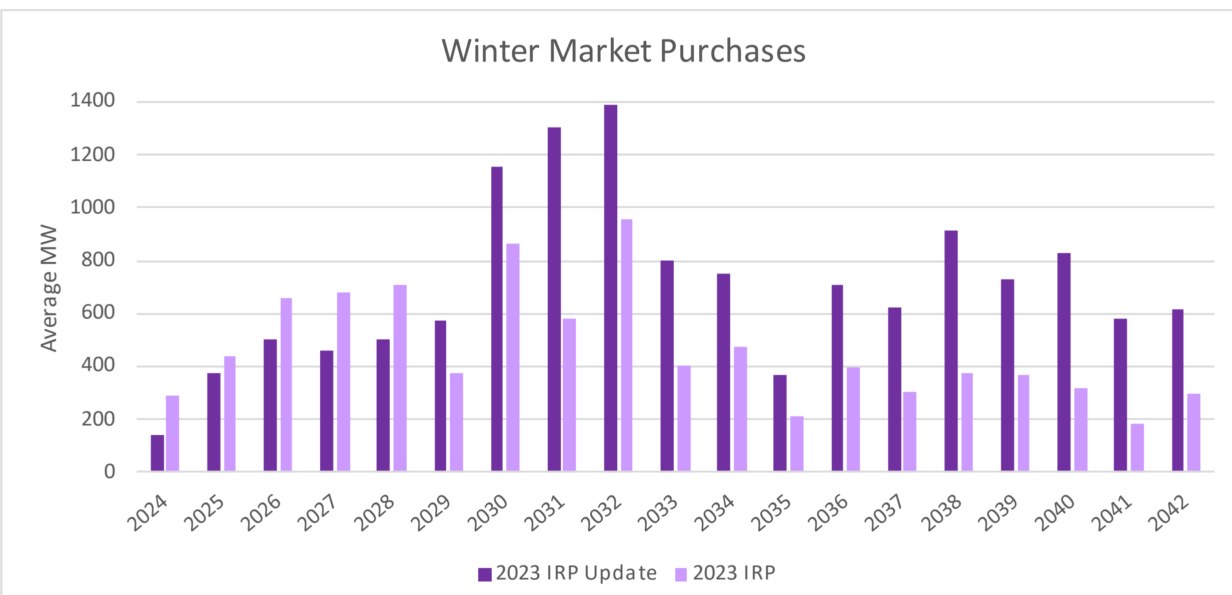


Figure 1.14 – 2023 IRP Update Preferred Portfolio Summer Market Purchases



*Note: "Summer Market Purchases" includes purchases from June through September while "Winter Market Purchases" includes purchases from December and January. While most data for tables and figures in this document comes from LT capacity expansion model results, this figure uses ST model results. For market data, it is appropriate to use ST model results because the ST model is run with an hourly granularity which more accurately represents the energy needed to meet load obligations compared to the less granular LT capacity expansion model.

Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. The operating capabilities of these facilities have been able to adapt to changes in the planning environment. For example, PacifiCorp has been able to lower operating minimums and optimize coal dispatch through the Western Energy Imbalance Market (WEIM or EIM). This in turn has enabled the company to both reduce fuel consumption and associated costs and emissions by increasingly buying 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. EPA's approval of Wyoming's ozone plan and the stay of EPA's disapproval of Utah's ozone plan results in fewer restrictions on coal-fired operation than were assumed in the 2023 IRP. With these updates, Utah coal resources are no longer planned to retire early, as shown in Table 1.1 Hunter and Huntington coal unit retirements, specifically, have returned to the schedule that had been previously indicated by PacifiCorp's 2021 IRP.

Table 1.1 – Coal Unit Retirements in the 2023 IRP and 2023 IRP Update

Coal			
Unit	2023 IRP Retirement Year (12/31/__) As Selected	2023 IRP Update Retirement Year (12/31/__) As Selected	Delta to 2023 IRP (Years)
Colstrip 3	2025	2025	-
Colstrip 4	2029	2029	-
Craig 1	2025	2025	-
Craig 2	2028	2028	-
DaveJohnston 1	2028	2028	-
DaveJohnston 2	2028	2028	-
DaveJohnston 3	2027	2027	-
DaveJohnston 4	2039	2039	-
Hayden 1	2028	2028	-
Hayden 2	2027	2027	-
Hunter 1	2031	2042	11
Hunter 2	2032	2042	10
Hunter 3	2032	2042	10
Huntington 1	2032	2036	4
Huntington 2	2032	2036	4
JimBridger 1	2037	2037	-
JimBridger 2	2037	2037	-
JimBridger 3	2037	2039	2
JimBridger 4	2037	2039	2
Naughton 1	2036	2036	-
Naughton 2	2036	2036	-
Wyodak	2039	2039	-

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

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

- 2028 = Jim Bridger Units 3-4, retrofitted with carbon capture technology in 2028, operates through 2039 (converted to gas conversion in 2030 and retired in 2037 in the 2023 IRP; unit life is extended by 2 years to capture 12 full years of investment tax credits)
- 2028 = Dave Johnston Units 1-2 retirement (same as in the 2023 IRP)
- 2028 = Craig Unit 2 retirement (same as in the 2023 IRP)
- 2028 = Hayden Unit 1 retirement (same as in the 2023 IRP)
- 2029 = Colstrip Unit 4 exit, Colstrip Unit 3 share is consolidated into Colstrip Unit 4 in 2025 (same as in the 2023 IRP)
- 2036 = Huntington Units 1-2 retirement, no emissions controls (SNCR installation in 2026, operating through 2032 in the 2023 IRP)
- 2039 = Dave Johnston Unit 4 retirement (same as in 2023 IRP)
- 2039 = Wyodak retirement, no emissions controls (SNCR installation in 2026, operating through 2039 in the 2023 IRP)
- 2042 = Hunter Units 1-3 retirement, no emissions controls (SNCR installation in 2026, operating through 2031 and 2032 in the 2023 IRP)

Resource Procurement and Requests for Proposals

As evaluated in the 2023 IRP, the OTR significantly restricted energy production in the summer among natural gas and coal-fueled resources in Wyoming and Utah, which triggered a need for incremental resources. EPA's approval of Wyoming's state OTR plan and the stay of EPA's disapproval of Utah's state OTR plan removes the restrictions that limit energy production in the summer from natural gas and coal-fueled resources in Wyoming and Utah. The 2023 IRP Update preferred portfolio demonstrates that with limited procurement of battery resources in the near-term, which can be achieved outside of a request for proposals process, there is a material benefit to scaling down and delaying resource acquisition until after 2030. This outcome supports the company's decision to suspend the 2022 All-Source Request for Proposals, which will be terminated. The proposed small-scale renewable request for proposal will not be issued until additional stakeholder outreach can be completed. The 2025 IRP will inform the next steps for incremental resource acquisition.

Carbon Dioxide Emissions

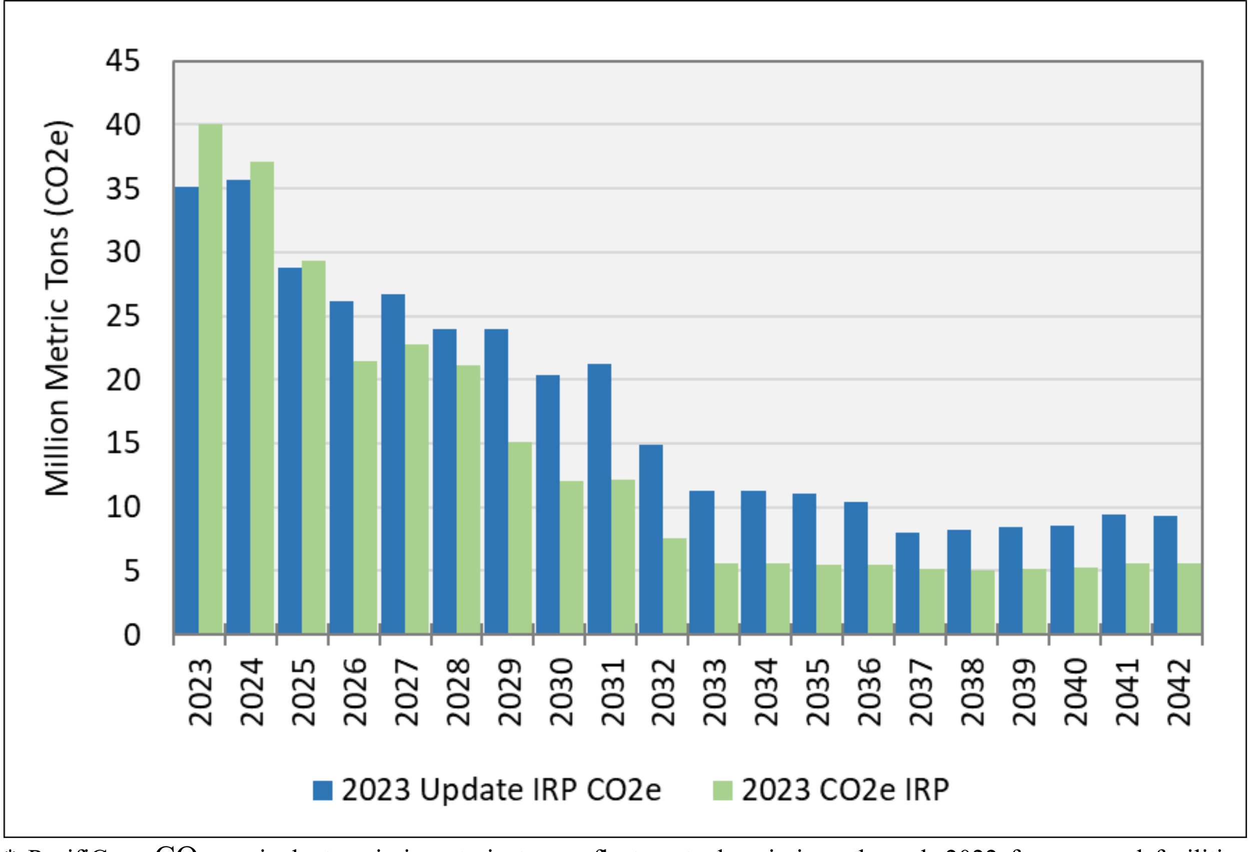
The 2023 IRP Update preferred portfolio reflects PacifiCorp's on-going efforts to provide valuable energy solutions for our customers that reflects a continued trajectory of declining carbon dioxide (CO_2) and other carbon dioxide equivalent (CO_2e) emissions resulting in a measure of total emissions.

PacifiCorp's emissions have been declining and continue to decline related to several factors including PacifiCorp's participation in the EIM and commitment to CAISO's Extended Day-Ahead Market (EDAM), which reduces customer costs and maximizes use of non-emitting renewable resources that have no fuel cost and that generate tax credits.

The chart below in Figure 1.15 compares projected annual CO_2e emissions between the 2023 IRP Update and 2023 IRP preferred portfolios. In this graph, emissions are assigned to market purchases at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour.

In the 2023 IRP Update, emissions are higher than projected in the 2023 IRP starting in 2026. Removal of the OTR, which limited summer generation from gas and coal-fueled resources, is a significant driver. Further, over the longer-term the load forecast in the 2023 IRP Update is higher than in the 2023 IRP. Importantly, the 2023 IRP Update preferred portfolio continues to show a continued downward trajectory in emissions over time. By 2030, average annual CO_2e emissions in the 2023 IRP Update preferred portfolio are reduced by 63% against the year 2005 baseline versus a reduction of 78% against the baseline in the 2023 IRP preferred portfolio. By the end of the planning horizon, system CO_2e emissions are projected to fall from 35.1 million metric tons in 2023 to 9.3 million tons in 2042—a reduction of 73.5%.

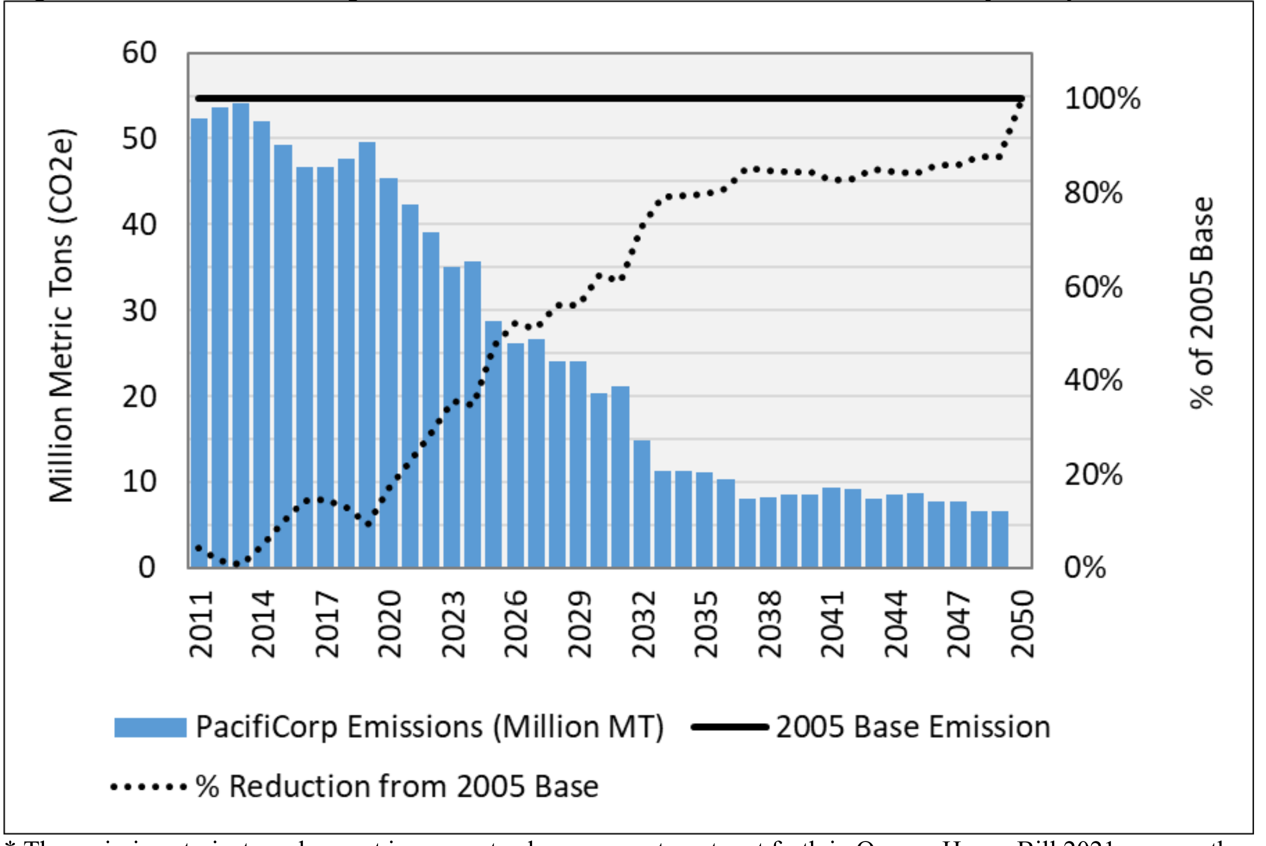
Figure 1.15 –Preferred Portfolio CO2e Emissions Comparison*



* 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 Update 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/megawatt-hour). Emissions from sales are not removed. Beyond 2042, emissions reflect the rolling average emissions of each resource from the 2023 IRP update preferred portfolio through the life of the resource.

Figure 1.16 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour 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_2e emissions are down 47% in 2025, 63% in 2030, 80% in 2035, 84% in 2040, 84% in 2045, and 100% in 2050 (assuming that by 2050, new gas-fired resources added in the preferred portfolio are fueled with a non-emitting fuel alternative.

Figure 1.16 – 2023 IRP Update Preferred Portfolio CO2e Emissions Trajectory*



* The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories.

Renewable Portfolio Standards

Figure 1.17 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the 2023 IRP Update 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.

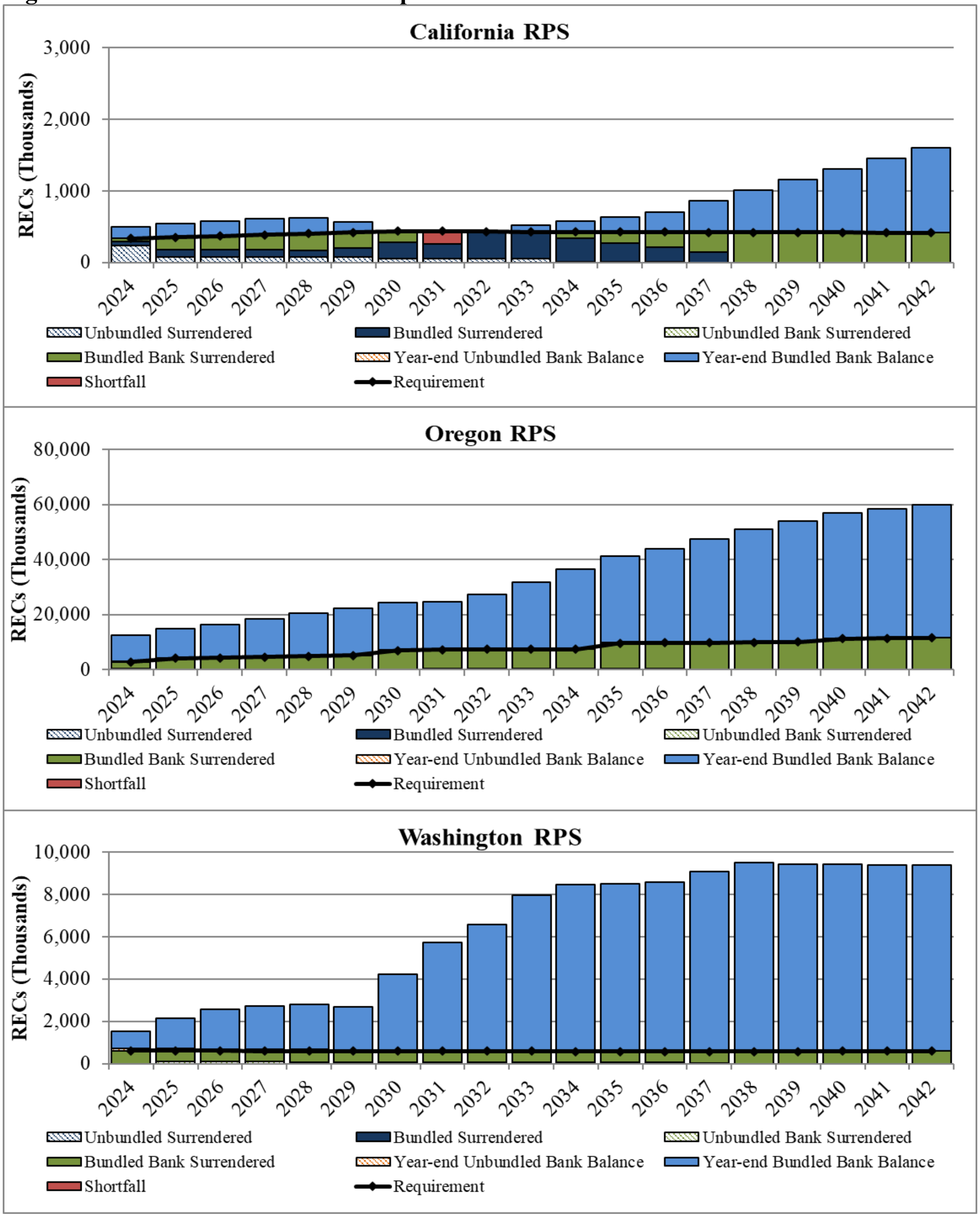
The California RPS compliance position will be met through year 2030 with owned and contracted renewable resources, as well as REC purchases. Beyond 2030, the company may need to purchase approximately ~175,000 RECs per year to meet the RPS target of 60% in years where a shortfall is projected.

Oregon RPS compliance is achieved through 2042 with the addition of new renewable resources in the 2023 IRP Update preferred portfolio.

Under PacifiCorp's 2020 Protocol and the Washington Interjurisdictional Allocation Methodology, Washington's RPS position is improved by receiving a system share of renewable resources across PacifiCorp's system, and there are no anticipated shortfalls.

While not shown, PacifiCorp meets the Utah 2025 state target to supply 20% of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources.

Figure 1.17 – Annual State RPS Compliance Forecast



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CHAPTER 2 – INTRODUCTION

This 2023 Integrated Resource Plan (IRP) Update describes resource planning activities following the filing of the Amended Final 2023 IRP on May 31, 2023, and continues the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. As the owner of the IRP Update and its action plan, all policy judgments and decisions concerning the IRP Update are made by PacifiCorp considering its obligations to its customers, regulators, and shareholders.

PacifiCorp's 2023 IRP Update preferred portfolio reflects updates to load, existing resources, signed contracts, transmission options, and modeling improvements. The 2023 IRP Update also includes variant analysis for carbon capture and nuclear technologies, a range of future market and environmental policy environments, and updated analysis of state-specific planning, such as Oregon's Clean Energy Plan and Washington's Clean Energy Implementation Plan.

PacifiCorp's selection of the 2023 IRP Update preferred portfolio is supported by comprehensive data analysis described in the chapters that follow. Chapter 3 describes the current planning environment, load updates, resource updates, state and federal policy updates, and transmission upgrades. Chapter 4 provides updated load-and-resource balance information. Chapter 5 describes changes to key inputs and assumptions relative to those used for the 2023 IRP. Chapter 6 presents the updated preferred portfolio, variant study results, and additional price-policy studies. This chapter also confirms that PacifiCorp's 2023 IRP Update preferred portfolio continues to include substantial new renewables facilitated by incremental transmission investments, along with demand-side management resources, significant storage resources, the Natrium™ Demonstration Project, and peaking resources. A status update on the 2023 IRP Action Plan is provided in Chapter 7. Finally, Appendix A provides additional load forecast details.

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CHAPTER 3 – THE PLANNING ENVIRONMENT

The 2023 Integrated Resource Plan (IRP) Update reflects changes to the planning environment and assumption updates since the Amended Final 2023 IRP was filed on May 31, 2023. PacifiCorp highlights these changes relative to the 2023 IRP conditions and assumptions impacting the 2024 to 2042 planning horizon.

Material Changes to Key Planning Assumptions

Key planning assumptions that have changed from the 2023 IRP filing include:

- EPA's approval of Wyoming's OTR plan
- Stay of EPA's disapproval of Utah's OTR plan

Additional items are discussed in summary below, with details provided further within this chapter.

Federal Policy Update

Federal Climate Change Legislation

To date, no federal legislative climate change proposal has been passed by the U.S. Congress. Federal climate change legislation is not anticipated in the near term but remains possible in the mid- to long-term.

New Source Performance Standards for Carbon Emissions from New and Existing Sources – Clean Air Act § 111(b) and (d)

New Source Performance Standards are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare, including thermal electric generating units. After two previous iterations, in May 2023, the EPA proposed new rules addressing greenhouse gas emissions from new and reconstructed natural gas-fueled combustion turbines (Clean Air Act Section 111(b) rule) and existing coal- and gas- or oil-fueled steam units and natural gas-fueled combustion turbines (Clean Air Act Section 111(d) rule).

Requirements for new combustion turbines are subcategorized based on capacity factor, where low-load units would be required to meet an emission limit, intermediate-load units would be required to use a blend of low-emitting hydrogen and natural gas, and base-load units would be required to use carbon capture and sequestration (CCS) technology or a high-percentage blend of low-emitting hydrogen.

The proposed requirements for existing units would take effect January 1, 2030, through state implementation plans. Requirements for existing gas and oil-fueled steam units are subcategorized based on capacity factor, where low-load units would be subject to routine maintenance to demonstrate no increase in emissions, intermediate-load units would be subject to an emission limit of 1,500 pounds of CO_2 per megawatt-hour-gross, and base-load units would be subject to an emission limit of 1,300 pounds of CO_2 per megawatt-hour-gross. Control equipment requirements for existing combustion turbines only apply to large, high load turbines that are greater than 300 megawatts in capacity and operate at a 50% capacity factor that is greater than 50%. These units would be required to begin using CCS with a 90% capture rate by 2035 or use a blend of low-emitting hydrogen starting in 2032. Requirements for existing coal-fueled units are subcategorized based on retirement date. Units with earlier retirement dates would be subject to less stringent requirements while units that commit to later retirement dates would be subject to annual capacity factor limits or natural gas co-firing requirements. Units that will continue operating after December 31, 2039, would be required to use CCS with a 90% carbon capture rate.

Clean Air Act Section 111 establishes a cooperative approach between the EPA and the states. The EPA establishes nationwide standards based on the best system of emissions reductions it identifies for a source category. States are then expected to develop plans to implement those standards at affected units. States may adopt the EPA's standards or develop state-specific standards that achieve the same air quality results. The EPA accepted comments on the proposal through August 8, 2023. Given the extensive comments submitted, it is uncertain how the final greenhouse gas rule will change. The scope and impacts of the final rule are uncertain until EPA takes final action on the proposals, the states submit any required state implementation plans (SIP), and any related litigation is exhausted.

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 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. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area determined to contribute to the nonattainment are required to reduce emissions. 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.

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. In addition to meeting the ozone NAAQS for areas within a state, states must also conduct an analysis of cross-state air pollution to determine 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 (the “Ozone Transport Rule” or “OTR”), which contained 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 focused on reducing NO_x, which are precursors to ozone formation. The proposed rule covered 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.

On May 24, 2022, the EPA 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 1% threshold instead of the one ppb threshold previously suggested by EPA that the states used to determine downwind impacts. Final disapproval of the SIPs would subject the states to the proposed CSAPR FIP for the 2015 ozone standard.

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. Until a final disapproval of Wyoming's SIP, Wyoming would not be subject to the CSAPR FIP. 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, with some updates and timeline changes from the proposed rule but included the stringent NOx emission reduction and control equipment requirements of the proposed rule.

Numerous states and industries challenged certain provisions of the CSAPR SIP disapprovals and the final CSAPR FIP, including PacifiCorp. The state of Utah and PacifiCorp filed petitions and motions for stay of EPA's denial of the Utah state plan with EPA and the U.S. Tenth Circuit Court of Appeals (Tenth Circuit), and the motion for stay was granted by the Tenth Circuit on July 27, 2023. The stay will remain in place while the case is litigated, or until further order of the court. The court held that the agency may not enforce the CSAPR FIP while the stay remains in place. The EPA also issued several interim final rules stating that the federal rule will not take effect in states in which the SIP disapprovals have been deferred or stayed.

The EPA finalized approval of Wyoming's interstate CSAPR SIP on December 19, 2023. Given the approval of the Wyoming SIP, PacifiCorp facilities in Wyoming are not subject to the CSAPR FIP. Given the court stay of the Utah SIP disapproval, PacifiCorp was not subject to the CSAPR FIP requirements during the 2023 ozone season. The Utah ozone case was transferred to the D.C. Circuit on February 16, 2024, for adjudication of the merits, leaving the stay in place. Requirements for the 2024 ozone season and beyond will depend on the outcome of litigation. In granting the stay, the court indicated that PacifiCorp and the other petitioners are likely to succeed on the merits.

In addition to litigation over SIP disapprovals, numerous appeals of the final CSAPR FIP were filed in four different circuit courts, and at least four motions to stay the final rule have been filed in those courts. On September 25, 2023, the D.C. Circuit denied the motion to stay the CSAPR FIP filed by several state and industry parties. The denial means that states that do not have stays on their SIP disapprovals are subject to the CSAPR FIP requirements. The states of Ohio, Indiana and West Virginia filed a request for an emergency stay of the CSAPR FIP Rule with the U.S. Supreme Court on October 13, 2023. Several industry groups representing utilities as well as pipeline, paper, cement and other industries affected by the rule filed supportive requests for stay on the same day. The U.S. Supreme Court heard oral arguments on the emergency stay requests February 21, 2024.

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 2022.

Utah Regional Haze

Environmental advocacy groups filed a petition for review in the Tenth Circuit on January 19, 2021, objecting to the revised Utah regional haze SIP which included EPA's withdrawal for FIP requirements at Hunter Units 1 and 2 and Huntington Units 1 and 2 to install SCR. 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. The EPA defended the SIP, with PacifiCorp and the state of Utah in support. On August 14, 2023, the Tenth Circuit denied the petition to vacate Utah's first planning period regional haze plan.

Utah Regional Haze Second Planning Period – 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 failed to make a final determination on the Utah SIP within 12 months as required under the Clean Air Act. Utah and PacifiCorp filed a deadline suit in the Utah Federal District Court in the fall of 2023, requesting the court to order EPA to make a final determination. Environmental advocacy groups also filed several deadline suits in the D.C. Federal District Court requesting EPA to make final determinations for numerous states, including Utah. PacifiCorp intervened in the D.C. Federal District Court and requested the case be transferred to the Utah Court. Those suits are pending in the two different courts.

Wyoming Regional Haze

Naughton – In its 2014 rule, EPA approved Wyoming's determination that BART for Units 1 and 2 was low-nitrous oxide burners (LNB) and over-fired air (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. On

August 15, 2023, the court determined EPA properly approved Wyoming's Naughton determination and denied environmental groups' petition.

Jim Bridger – 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 Wyoming SIP submission for Jim Bridger and is expected to conduct a separate federal public comment process on the plan. On March 9, 2023, PacifiCorp submitted a notice of compliance and request for termination of the EPA order. The Wyoming consent decree remains in effect. The conversion process is underway at the units.

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. 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. Litigation for the Wyodak case recommenced when the mediation process was not successful. PacifiCorp and Wyoming challenged EPA's denial of the Wyoming SIP and imposition of a FIP requiring Wyodak to install SCR equipment. On August 15, 2023, the Tenth Circuit found EPA's disapproval of Wyoming's SIP for Wyodak unlawful and remanded the SIP to EPA for further review in accordance with the requirements of the Clean Air Act

Wyoming Regional Haze Second Planning Period – On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis to Wyoming, which analyzed PacifiCorp's Naughton, Jim Bridger, Dave Johnston, and Wyodak plants. The four-factor analysis 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. EPA failed to make a final determination on the Wyoming SIP within 12 months, as required under the Clean Air Act. Wyoming and PacifiCorp filed a deadline suit in the Wyoming Federal District Court in the fall of 2023, requesting the court to order EPA to make a final determination. Environmental advocacy groups also filed several deadline suits in the D.C. Federal District Court requesting EPA to make final determinations for numerous states, including Wyoming. PacifiCorp intervened in the D.C. Federal District Court and requested the case be transferred to the Wyoming Court. Those suits are pending in the two different courts.

Colorado Regional Haze

Colorado Second Planning Period – Colorado's regional haze SIP for the second planning period was adopted in phases in 2020 and 2021 by the Colorado Air Quality Control Commission. The SIP includes retirements of Craig Units 1 and 2 by 2025 and 2028, respectively, and Hayden Units

1 and 2 by 2028 and 2027, respectively. Colorado submitted its second planning period regional haze SIP to EPA. However, EPA has not yet acted on the Colorado SIP. The Colorado SIP is part of the deadline suit filed by environmental advocacy groups in the federal D.C. District Court.

Mercury and Hazardous Air Pollutants

On April 5, 2023, the EPA released a proposal to revise several aspects of the Mercury and Air Toxics Standards rule following the agency's review of the 2020 Residual Risk and Technology Review. The EPA proposes two specific standard changes - one applicable to all covered units and one specific to the existing lignite subcategory. The EPA proposes a more stringent standard for emissions of filterable particulate matter, the surrogate standard for non-mercury metals for coal-fueled electric generating units. The EPA proposes to reduce the filterable particulate matter emission standard by two-thirds based on a demonstration that 91% of coal-based capacity, which has not been identified as retiring before the proposed compliance period, has an emission rate at or below the proposed limit. The EPA also proposes to require continuous emissions monitoring for filterable particulate matter to demonstrate compliance with the revised standard. Compliance would be due no later than three years after the effective date of a final rule. the EPA accepted comments on the proposal through June 23, 2023. PacifiCorp is not included in the lignite subcategory. PacifiCorp has determined that compliance can be achieved with existing controls. Until the EPA takes final action on the proposal, the full impacts of the rule cannot be determined.

Coal Combustion Residuals

EPA finalized its Holistic Approach to Closure: Part A rule (“Part A rule”) in September 2020. A provision in Part A allows demonstrations to be submitted to the EPA allowing for operation of unlined Coal Combustion Residual (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 12, 2023, Jim Bridger FGD Pond 2 ceased receiving waste, and the newly constructed FGD Pond 3 came into service. The EPA was notified on October 12, 2023, of PacifiCorp’s withdrawal of its pending Part A alternative closure demonstration request. The Naughton South Ash Pond alternative closure demonstration remains under EPA review.

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. 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. The state of Wyoming filed a deadline suit in Wyoming federal district court on October 8, 2023, asking the court to require EPA to act on its application in accordance with the requirements of Resource Conservation and Recovery Act, which requires EPA to make a determination within 180 days of submission.

On May 18, 2023, the EPA proposed the legacy surface impoundments rule and accepted comment on the proposal through July 17, 2023. The proposal encompasses legacy surface impoundments, which are inactive surface impoundments at inactive facilities; and CCR management units, which include CCR surface impoundments and landfills that closed prior to October 19, 2015, inactive CCR landfills, and other areas where CCR has been or is managed directly on the land. CCR management units include all units meeting that definition at active CCR facilities, as well as those at inactive facilities with one or more legacy surface impoundment. EPA proposes to impose substantially the same regulatory obligations for both legacy surface impoundments and CCR management units as are applicable to currently regulated units, including groundwater monitoring and corrective action. All legacy surface impoundments and CCR management units would be required to initiate closure, including reclosure, within one year after the rule is finalized.

The EPA includes lists of potential legacy surface impoundments and CCR management units in the rulemaking docket, and those lists include several PacifiCorp facilities. The EPA also specifically identifies PacifiCorp's Huntington Power Plant as a potential CCR management unit damage cases based on the EPA's review of compliance information. PacifiCorp submitted comments on the proposed rule under Berkshire Hathaway Energy, and corrected the record, noting that: (1) historical impoundments, which were closed according to state requirements and no longer contain CCR or liquids, should be removed from the list of CCR management units; (2) the EPA erroneously identified the Old Landfill at PacifiCorp's Huntington generating facility as a potential damage case; and (3) two impoundments at PacifiCorp's former Carbon generating facility are incorrectly included on the list of legacy impoundments because PacifiCorp never managed or disposed of CCR materials in wastewater ponds at the former Carbon generating facility.

Until the proposals are finalized and fully litigated, PacifiCorp cannot determine whether additional action may be required. The EPA published a Notice of Data Availability (NODA) on November 14, 2023, seeking additional data in support of its legacy proposed rule. The NODA sought comments and information on two specific issues: (1) an updated list of legacy impoundments and CCR management units, based on information received from environmental groups during the comment period for the proposed rule; and (2) a risk assessment for legacy impoundments and CCR management units. The EPA included lists of potential legacy surface impoundments and CCR management units in the rulemaking docket, and those lists included several PacifiCorp facilities. Berkshire Hathaway Energy identified a number of obvious errors and inaccuracies in those lists and submitted its comments on December 11, 2023. The EPA has indicated it intends to finalize the legacy surface impoundment rule by May 2024.

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 IRA 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 tax credit (ITC) and production tax credits (PTC) 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 PTCs at full value through December 31, 2024. Solar projects are newly eligible to apply the PTC 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).

Clean Energy Financing Program – Inflation Reduction Act

Under the *Title 17 Clean Energy Financing Program*, the Loan Program Office (LPO) can finance projects in the United States that support clean energy deployment and energy infrastructure reinvestment to reduce greenhouse gas emissions and air pollution. *Title 17* was created by the Energy Policy Act of 2005 and has since been amended, most recently by the Infrastructure Investment and Jobs Act in 2021 and the Inflation Reduction Act in 2022. The legislation expanded the scope of *Title 17* to include certain state-supported projects and projects that reinvest in legacy energy infrastructure, and it leverages additional loan authority and funding available for projects involving innovative energy technologies.

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 electric vehicles and fuel cell electric vehicles, and require a traction battery that has at least seven kilowatt-hours. An available tax credit under the CVC may be limited by the vehicle's manufacturer suggested retail price 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 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% of the cost of installed equipment for ten years and will then step down to 26% in 2033 and 22% in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC would be set at 26%. 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 kilowatt-hours for residential customers and 5 kilowatt-hours 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, the 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).

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 amount of 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% below 1990 levels by 2030. CARB was subsequently directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target. In July 2017, California Governor Jerry Brown signed AB 398, extending the state's California Cap and Trade program from January 1, 2021, through December 31, 2030. In 2022, CARB issued a revised scoping plan establishing emissions reduction targets post-2030. In 2023, CARB held two workshops discussing cap and trade program changes the agency could consider. The agency is expected to open a formal rulemaking process in 2024.

In 2002, California established a renewable portfolio standard (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. Most recently, in September 2018, Governor Jerry Brown signed into law the 100% Clean Energy Act of 2018, Senate Bill (SB) 100, which requires utilities to procure 60% of their electricity from renewables by 2030 and enabled all the state's agencies to work toward a longer-term planning target for 100% of California's electricity to come from renewable and zero-carbon resources by December 31, 2045.

Oregon

In 2007, Oregon enacted SB 838 establishing an RPS requirement in Oregon. Under SB 838, utilities are required to deliver 25% 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% 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% by 2025, 35% by 2030, 45% by 2035, and 50% 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 (HB) 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. PacifiCorp's 2023 IRP and 2023 IRP Update include modeling as appropriate to support HB 2021. HB 2021 also increases state requirements for small-scale renewable energy projects, to 10% of aggregate electrical capacity by 2030 and provides policy support for community-based renewable energy projects, though without specific requirements. HB 2021 is complementary to – but does not modify – Oregon's longstanding RPS requirements.

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% 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 Engrossed Second Substitute House Bill (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% below 1990 levels by 2035; and (3) by 2050, reduce emissions to 50% below 1990 levels or 70% 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% of its electricity from renewable and non-emitting resources by 2045.

Finally, in 2021, Washington passed the Climate Commitment Act, which establishes a cap-and-trade program to be implemented by no later than January 1, 2023, through the regulatory rulemaking process. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utility allowances within the cap-and-trade program are aligned with the CETA renewable energy requirements. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington state. Utilities are provided allowances at no cost to "mitigate the cost burden" of the program on customers,

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% of their 2025 adjusted retail electric sales. PacifiCorp filed its most recent progress report with the Public Service Commission of Utah on December 29, 2023.

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 a program on December 20, 2021.

In March 2024, Utah passed S.B. 224, Energy Independence Amendments. Utah's S.B. 224 does not become effective until May 1, 2024, and as such was not included in the planning environment for the 2023 Update. Portfolio modeling was well advanced by the 2024 legislative sessions and proceeded independently of those actions.

Wyoming

In March 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% cost recovery in rates for the cost of the power purchase agreement and the agreement is 100% 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 requires 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 would only apply to generation allocated to Wyoming customers. HB 200 will require 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 Commission finalized administrative rules to implement HB 200, which became effective in January 2022. The administrative rules require public utilities to file an initial application to establish intermediate standards for compliance by March 31, 2022, and an application to establish the final plan for compliance by March 31, 2024. PacifiCorp filed the initial application with the Commission on March 31, 2022, its first update to the initial application on March 31, 2023, and PacifiCorp's final plan on March 29, 2024 as required. During the 2024 legislative session, the Wyoming Legislature passed SF 42, low-carbon reliable energy standards amendments that has been signed into law. PacifiCorp is currently analyzing the amendments to determine how it will affect the company's plan to implement low-carbon energy portfolio standards utilizing carbon capture technology.

During the 2022 legislative session, the Wyoming Legislature passed HB 131, nuclear power plant and storage amendments, that will help facilitate development of the Natrium nuclear demonstration project. The bill modifies existing laws to clarify the authority of the United States Nuclear Regulatory Commission. The bill also requires the operator of the facility, at least 30 days prior to construction, to submit a report identifying the number of jobs expected to be created by the project, the amount of local and state taxes estimated to be generated by the project, and the anticipated benefits and impacts that will accrue to the state and local community from the project. With respect to SF 159, the bill provides that the requirements of that law shall not apply to a public utility that replaces a coal-fired generation facility with an advanced nuclear reactor. Finally, the bill exempts tax payments, but provides that, beginning July 1, 2035, the exemption only applies if not less than 80% of the uranium is sourced in the United States.

Several bills were recently signed into law from the 2024 Wyoming legislative session that PacifiCorp is evaluating that include SF 22, public service commission electricity reliability; SF 23, public service commission energy resource procurement; and SF 24, public service commission integrated resource plans. These new statutes will go into effect in 2024 and may be considered further in the next IRP.

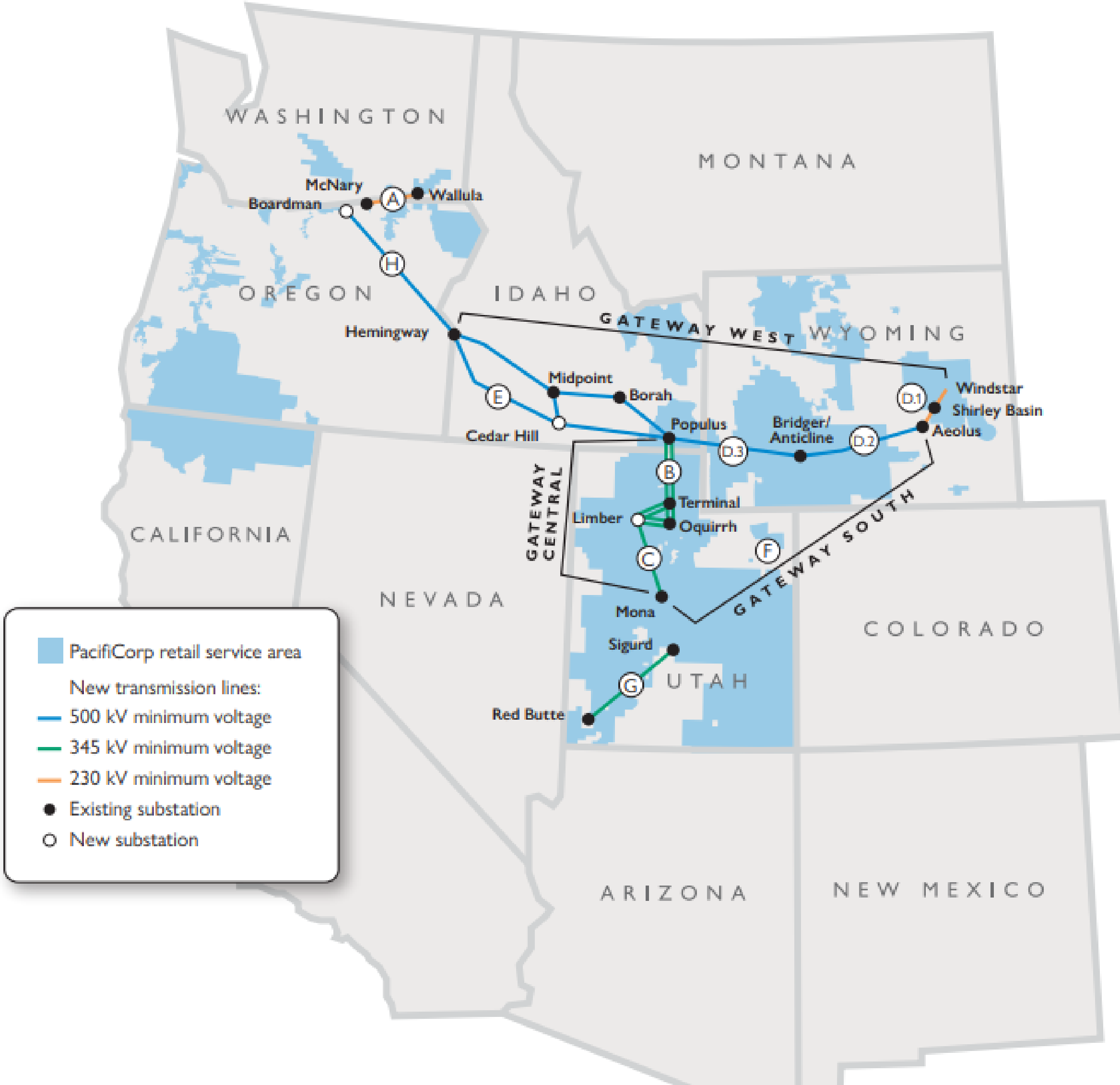
Greenhouse Gas Emission Performance Standards

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 pounds CO_2 per megawatt-hour, 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 pounds CO_2 per megawatt-hour.

Energy Gateway Transmission Program Planning

The Energy Gateway transmission project continues to play an important role in PacifiCorp's commitment to provide safe, reliable, reasonably priced electricity to meet the needs of our customers. Energy Gateway's design and extensive footprint provides needed system reliability improvements and supports the development of a diverse range of cost-effective resources required for meeting customers' energy needs. The IRP has incorporated Energy Gateway as part of a solution for delivering the least cost resource portfolio for multiple IRP planning cycles. PacifiCorp continues to develop methods, in parallel with current industry best practices and regional transmission planning requirements, to better quantify all the benefits of transmission that are essential to serve customers. For example, Energy Gateway is designed to relieve operating limitations, increase capacity, and improve operations and reliability in the existing electric transmission grid. Figure 3.1 shows a high-level geography of the Energy Gateway transmission project.

Figure 3.1 – Energy Gateway Map



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

Energy Gateway Transmission Project Updates

Wallula to McNary (Segment A)
This project was placed in service in January 2019.

Gateway West (Segments D and E)
Under the National Environmental Policy Act (NEPA), the U.S. Bureau of Land Management (BLM) has completed the environmental impact statement (EIS) for the Gateway West project. The BLM released its final EIS on April 26, 2013, followed by the record of decision (ROD) on November 14, 2013, providing a right-of-way grant for all of Segment D and for all but two segments of Segment E, followed with a record of decision on these two segments of the line on April 19, 2018:

- Gateway West (Segment D1): The project includes a new single-circuit 230 kilovolt line that will run approximately 76 miles between the existing Windstar substation in eastern Wyoming and the Aeolus substation near Medicine Bow, Wyoming, which includes a loop-in to the existing Shirley Basin 230 kilovolt substation. The Aeolus – Shirley Basin 230 kilovolt line section (16.7 miles of the 76 miles) was energized in November 2020. This project was included in the 2021 IRP for acknowledgement, and is currently under construction with an in-service date of 2024.

- Gateway West (Segment D2): This single-circuit 500 kilovolt segment was placed in service November 2020.

- Gateway West (Segment D3): A single-circuit 500 kilovolt line running approximately 200 miles between the new Anticline substation which was placed in-service in November 2020 with the energization of Gateway West Segment D.2 and the Populus substation in southeast Idaho. The line is scheduled in service 2031 at the earliest.

Gateway West (Segment E)
The Populus-to-Hemingway transmission project consists of two single-circuit 500 kilovolt lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho. The estimated line in service for customers is 2036 at the earliest.

Gateway South (Segment F)
This 416-mile, high-voltage 500 kilovolt transmission line and associated infrastructure runs from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This project was included in the 2021 IRP for acknowledgement, and is currently under construction with an in-service date of 2024.

Boardman to Hemingway (Segment H)
The Boardman to Hemingway project represents a significant improvement in the connection between PacifiCorp's east and west control areas and will help deliver more diverse resources to serve its customers in Oregon, Washington, and California. Idaho Power leads the permitting efforts on this project and PacifiCorp continues to support the permitting efforts under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.

The BLM's ROD was issued in November of 2017, followed by the U.S. Forest Service ROD issued on November 9, 2018. The Oregon Energy Facilities Siting Council's final order on the Site Certificate is currently under process. In January 2020, the three parties signatory to the permitting agreement entered a non-binding term sheet that addresses the terms required to move the project to the next step of construction.

In-Service Dates

Table 3.1 summarizes the in-service dates for segments of the Energy Gateway transmission project.

Table 3.1 - Energy Gateway Segment In-Service Dates

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	118 mi	• Status: under construction • 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: 2031 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2036 earliest
(F) Aeolus-Mona/Clover	500 kV single circuit	416 mi	• Status: under construction • 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: 2026-2027

Regional Markets

Increased renewable generation has 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 EIM. The EIM became operational November 1, 2014, and currently has 22 utilities participating with Berkshire

Hathaway Energy Montana planning to enter in 2026.[1] The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using fifteen-minute interchange scheduling and five-minute dispatch. The CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. The CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. In December 2022, PacifiCorp announced its plan to join the CAISO's Extended Day-Ahead Market which is an extension of the EIM with planning practices that are done in the day-ahead timeframe.

In December 2021, it was announced that the Western Resource Adequacy Program (WRAP), administered by the Western Power Pool (WPP), formerly known as the Northwest Power Pool, had entered the first stage of implementation. The WRAP consists of 22 participants, including PacifiCorp, who are working on the remaining program design questions and outstanding issues. The WPP has partnered with the Southwest Power Pool (SPP) to provide program operation services, including facilitating the collection of participants data to perform modeling for the upcoming seasons.[2]

This program includes two components, a forward showing (FS) planning program and an operational 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. The WRAP will create a capacity resource adequacy (RA) program with a demonstration of deliverability. 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, WPP and WRAP participants are only working to implement the capacity RA program at this time.

The WRAP does not replace or supplant the resource planning processes used by states or provinces or the regulatory requirements of the Federal Energy Regulatory Commission , North America Electric Reliability Corporation or Western Electricity Coordinating Council. The program is designed to be supplemental and complementary to those processes and requirements.

[1] https://www.westerneim.com/Pages/About/default.aspx
[2] https://www.westernpowerpool.org/news/wrap-announces-full-participation-of-phase-3a

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CHAPTER 4 – LOAD-AND-RESOURCE BALANCE

Introduction

This chapter presents an update to PacifiCorp's load-and-resource balance. Updates to PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are summarized in Appendix A. Updates to PacifiCorp's load forecast, resources, and capacity position are presented and summarized in this chapter.

System Coincident Peak Load Forecast

The 2023 Integrated Resource Plan (IRP) Update relies on PacifiCorp's May 2023 load forecast. Figure 4.1 compares PacifiCorp's most recent load forecast to the forecast used for the 2023 IRP. Figure 4.2 compares PacifiCorp's most recent coincident system peak load forecast to the forecast used for the 2023 IRP. Considering that PacifiCorp analyzes incremental energy efficiency and direct-load control programs as demand-side resource options in its IRP, both figures exclude incremental energy efficiency savings and direct-load control capacity included in the updated resource portfolio. The compounded average annual growth rate (CAGR) for system load is 2.13% over the period 2024 through 2042. The CAGR for system coincident peak is 1.80% over the period 2024 through 2042. Over the 2024 to 2027 timeframe, lower projected demand from data centers results in a lower energy and peak load forecast, while data center expectations over the long-term results in a higher forecast from 2028 and on relative to projected loads used in the 2023 IRP.

Figure 4.1 – Forecasted Annual Load (GWh)

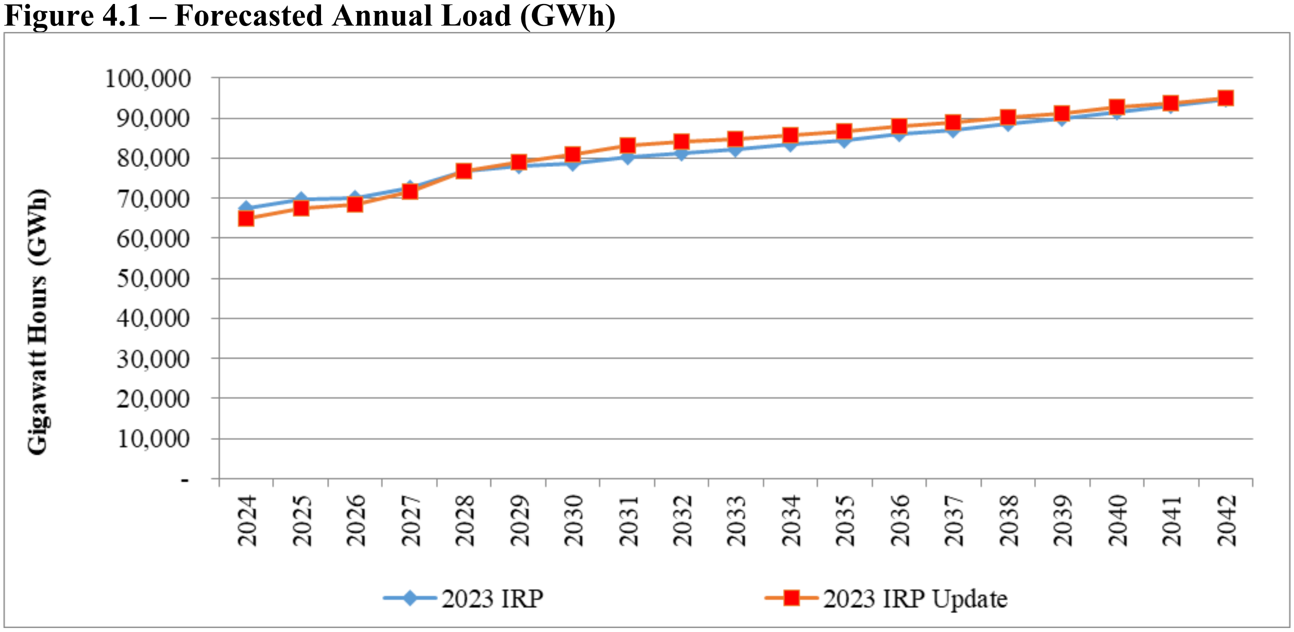
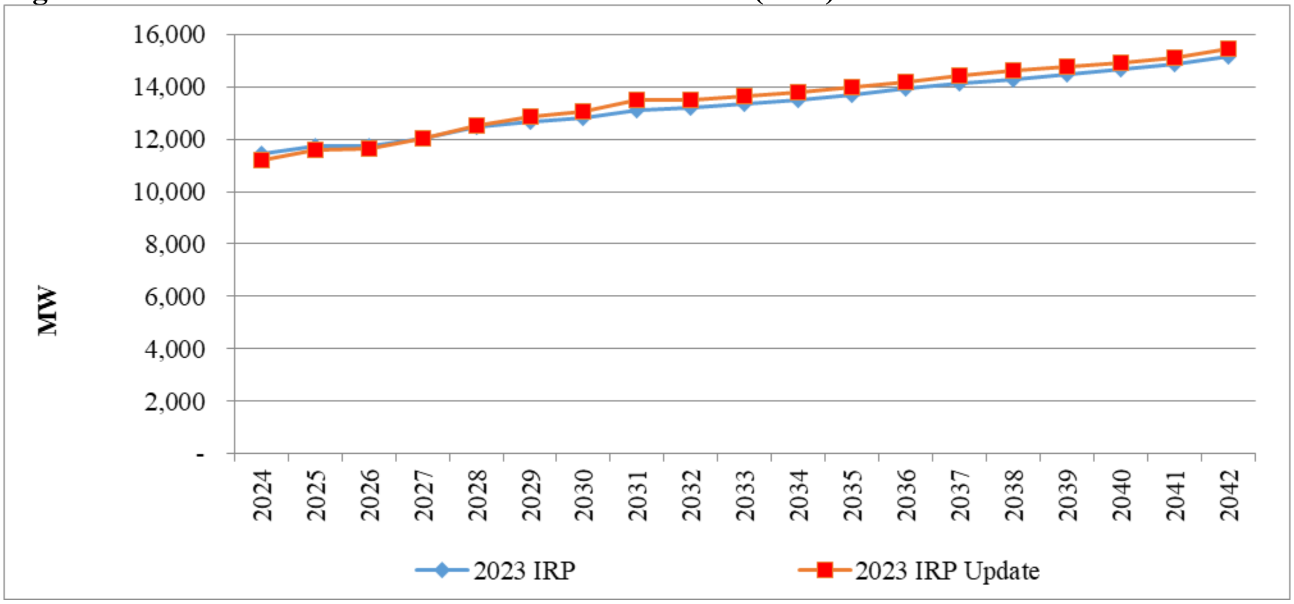


Figure 4.2 – Forecasted Annual Coincident Peak Load (MW)



Resource Updates

Table 4.1 summarizes recent long-term contracts that have been executed and modeled in PLEXOS since the 2023 IRP was prepared.

Table 4.1 – New Power Purchase Agreements

Power Purchase Agreements	Resource Type	Capacity (MW)	State	COD Year
Customer Preference / Oregon Schedule 272				
Hornshadow Solar	Solar	100	Utah	2025
Hornshadow Solar II	Solar	200	Utah	2025
	Sub-total	***300***		
Oregon Community Solar				
7 Mile Solar	Solar	1.0	Oregon	2024
Antelope Creek Solar	Solar	2.3	Oregon	2024
Orchard Knob Solar	Solar	2.3	Oregon	2024
Pine Grove Solar	Solar	1.4	Oregon	2024
Round Lake Solar	Solar	1.0	Oregon	2024
Sunset Ridge Solar	Solar	2.3	Oregon	2024
	Sub-total	***10.1***		
	Total	***310.1***		

Updated Capacity Load-and-Resource Balance

Load-and-Resource Balance Components

The capacity balance makes use of the following main component categories: resources, obligations, reserves, system position, and available front-office transactions (FOTs).

The resource categories include resources by type—thermal, peaker, hydroelectric, wind, solar, other renewable, storage, qualifying facilities, purchases, and sales. Categories in the obligation section include load, private generation, existing demand response (includes interruptible contracts), and new energy efficiency from the updated preferred portfolio.

A description of each of the resource categories is provided below.

Existing Resources

Capacity contribution is a measure of the ability for a resource to reliably meet demand. There are many possible ways to attribute capacity to specific resources and the portfolio modeling in the 2023 IRP Update does not rely on a specific capacity contribution for each resource during portfolio development, in part because the reliability benefits of the next resource of a given type may not be the same as the reliability benefits from resources of that type already included in a portfolio. Assumptions used to calculate capacity contribution in the load and resource balance presented in this chapter are described below.

Thermal and Peakers

These categories include all thermal plants. The capacity balance counts these plants at their expected availability.[1] This includes the existing fleet of coal-fueled units, coal-fueled units that have converted to natural gas-fueled, and natural gas combustion turbines and combined cycle combustion turbines. Presently, these thermal resources account for approximately three quarters of the firm capacity available in the PacifiCorp system.

Energy Storage

Energy storage resources can be called upon as needed, but only for a limited duration before they must be recharged. PacifiCorp's recent capacity contribution analysis in the 2021 IRP (Appendix K: Capacity Contribution) indicated that a four-hour duration energy storage resource would have a contribution of around 80%. For the purpose of the load and resource balance in the 2023 IRP Update, capacity contribution is based on the effective load carrying capability (ELCC) and the relationship between duration and contribution was assumed to be linear, so that energy storage with a five-hour duration would have a contribution of around 100% (less forced outages), and energy storage with a two-hour duration would have a contribution of around 40%. PacifiCorp anticipates that the capacity contribution of energy storage will fall over time as it makes up a greater portion of supply. With four gigawatts of energy storage in the 2023 IRP Update preferred portfolio, the contribution from four-hour duration energy storage may fall from 80% to 50% or lower. However, for the 2023 IRP Update load and resource balance, the current contribution level applies throughout the horizon.

[1] After derating for forced outages and maintenance during critical hours.

Variable Energy Resources: Wind and Solar
The availability of wind and solar resources is dependent on weather conditions. With access to wind and solar technologies and a broad geographic area, PacifiCorp's system is better suited to utilizing the capacity provided by wind and solar than most other utilities. However, many periods still exist in which both wind and solar output is at low levels, both in individual hours, and over an extended length of time. While short-duration energy storage can help to address a few hours of shortfalls, weather events which result in low variable energy resource output over multiple days limit the capacity contribution of these resources, as well as the contribution of short-duration energy storage. The contribution of wind and solar presented in the 2023 IRP Update load and resource balance is based on the ELCC of these resource types and is further allocated to individual resources based on their expect output during capacity critical hours, when the remaining load after netting out variable energy resources is highest. As with energy storage, PacifiCorp anticipates that the capacity contribution of wind and solar will fall over time as it makes up a greater portion of supply. With many gigawatts of wind and solar additions in the 2023 IRP Update preferred portfolio, the total contribution from these resources is likely to rise slowly from levels achieved in the next few years as the incremental benefit of each additional increment of wind and solar in critical hours will be lower than the benefits of previous additions. However, for the 2023 IRP Update load and resource balance, the current contribution level applies throughout the horizon.

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, private generation, new energy efficiency from the preferred portfolio, and existing demand response (including interruptible contracts). The following are descriptions of each of these components:

Load and Private Generation
The largest component of the obligation is retail load. In the 2023 IRP Update, 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 Balancing Authority Areas thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks. The energy balance counts the average load on a monthly basis. For simplicity, load net of private generation is referred to as load in the following sections.

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 was a level of 2022 energy efficiency that was not incorporated in the forecast for the 2023 IRP. The 2022 energy efficiency forecast of 100 megawatts was accounted for by adding an existing energy efficiency resource in the load-and-resource balance; this adjustment was not required for the 2023 IRP Update because the 2022 projected embedded energy efficiency is included in the load forecast. The energy efficiency line includes the selected energy efficiency from the 2023 IRP Update preferred portfolio.

Demand Response

Existing demand response program capacity is categorized as a reduction to peak load. 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 load reduction's timing and persistence 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 program design or event noticing requirements). Also included in the demand response category are existing interruptible contracts. PacifiCorp has had interruptible contracts for approximately 203 megawatts of peak load interruption capability for many years. These contracts are a key aspect of the retail service provided to the associated customers and absent from these contracts their demand would 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).

System Position

The system position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

Capacity Balance Determination and Results

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 + Peaker + Hydro + Wind + Solar + Other Renewables + Storage + Purchases + Qualifying Facilities – Firm Sales

The peak load, private generation, existing demand response, 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 Energy Efficiency

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

Planning Reserves = Obligation x PRM

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

System Position = (Existing Resources) – (Obligation + Planning Reserves)

Capacity Balance Results

Table 4.2 and Table 4.3 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target PRM of 13% to calculate the planning reserve amount. Balances for PacifiCorp's system and 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.

Table 4.2 – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2023 IRP Update (2024-2033) (Megawatts)[2]

East	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Thermal	6,805	6,852	6,769	6,769	6,546	6,234	6,234	6,234	6,234	6,234
Peaker	352	352	352	352	352	352	352	352	352	0
Hydroelectric	60	60	60	60	60	60	60	60	60	60
Wind	504	716	701	701	701	701	681	649	649	649
Solar	279	356	600	595	591	586	582	578	574	570
Other Renewable	41	41	41	41	41	41	41	41	41	41
Storage	1	1	496	496	496	496	496	496	496	496
Purchase	120	120	120	120	120	120	120	120	120	120
Qualifying Facilities	359	358	356	354	352	350	348	346	343	334
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,521**	**8,855**	**9,495**	**9,489**	**9,260**	**8,941**	**8,914**	**8,877**	**8,869**	**8,505**
Load	7,679	7,947	7,877	8,137	8,556	8,727	8,906	9,181	8,972	9,105
Private Generation	(102)	(143)	(111)	(141)	(174)	(213)	(256)	(304)	(151)	(175)
Existing - Demand Response	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)
New Energy Efficiency	(132)	(217)	(269)	(343)	(450)	(534)	(614)	(743)	(814)	(932)
East Total obligation	**6,951**	**7,092**	**7,003**	**7,160**	**7,437**	**7,486**	**7,541**	**7,639**	**7,511**	**7,504**
Planning Reserve Margin (13%)	904	922	910	931	967	973	980	993	976	975
East Obligation + Reserves	7,854	8,014	7,913	8,090	8,404	8,459	8,522	8,632	8,488	8,479
East Position	666	842	1,582	1,399	855	482	393	245	381	25
Available Market Purchases	825	825	825	825	500	500	500	500	500	500
West										
Thermal	878	878	872	872	872	872	736	736	736	736
Peaker	0	0	0	0	0	0	0	0	0	0
Hydroelectric	691	695	692	700	700	699	699	699	699	699
Wind	56	56	56	56	56	56	56	56	56	56
Solar	54	54	54	53	53	53	53	52	52	52
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	146	193	192	192	191	190	190	190	183	183
Sale	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
West Existing Resources	**1,818**	**1,868**	**1,860**	**1,866**	**1,866**	**1,864**	**1,727**	**1,726**	**1,720**	**1,719**
Load	3,667	3,842	3,931	4,111	4,257	4,466	4,593	4,817	4,813	4,870
Private Generation	(45)	(69)	(68)	(89)	(111)	(137)	(166)	(201)	(111)	(130)
Existing - Demand Response	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
New Energy Efficiency	(64)	(123)	(134)	(142)	(176)	(205)	(211)	(263)	(252)	(269)
West Total obligation	**3,538**	**3,629**	**3,708**	**3,859**	**3,949**	**4,104**	**4,195**	**4,331**	**4,429**	**4,450**
Planning Reserve Margin (13%)	460	472	482	502	513	533	545	563	576	578
West Obligation + Reserves	3,998	4,101	4,190	4,361	4,462	4,637	4,740	4,895	5,005	5,028
West Position	(2,179)	(2,232)	(2,331)	(2,495)	(2,596)	(2,773)	(3,013)	(3,169)	(3,285)	(3,309)
Available Market Purchases	3,000	3,000	3,000	3,000	500	500	500	500	500	500
System										
Total Resources	10,339	10,724	11,355	11,355	11,125	10,804	10,642	10,603	10,589	10,224
Obligation	10,489	10,721	10,711	11,019	11,386	11,589	11,736	11,970	11,940	11,954
Planning Reserves (13%)	1,364	1,394	1,392	1,432	1,480	1,507	1,526	1,556	1,552	1,554
Obligation + Reserves	11,852	12,114	12,103	12,451	12,867	13,096	13,262	13,527	13,492	13,508
System Position	(1,513)	(1,391)	(748)	(1,096)	(1,741)	(2,292)	(2,621)	(2,924)	(2,904)	(3,284)
Available Market Purchases	3,825	3,825	3,825	3,825	1,000	1,000	1,000	1,000	1,000	1,000
Uncommitted FOTs to meet remaining Need	1,513	1,391	748	1,096	1,000	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	0	0	0	0	(741)	(1,292)	(1,621)	(1,924)	(1,904)	(2,284)

[2] The DSM line includes selected Class 2 DSM from the 2023 IRP Update resource portfolio.

Table 4.2 (cont.) – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2023 IRP Update (2034-2042) (Megawatts)[3]

East	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	6,234	6,234	6,234	4,802	4,104	4,104	2,890	2,890	2,890
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	60	60	60	60	60	59	60	60	60
Wind	649	649	649	649	649	649	649	547	547
Solar	567	563	559	525	521	518	515	511	508
Other Renewable	41	41	41	41	13	13	13	13	13
Storage	495	495	495	495	495	495	495	495	495
Purchase	120	120	120	120	120	120	120	120	120
Qualifying Facilities	330	328	323	272	270	263	262	261	259
Sale	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,496**	**8,490**	**8,481**	**6,965**	**6,233**	**6,221**	**5,003**	**4,897**	**4,892**
Load	9,223	9,361	9,564	9,726	9,867	9,980	10,112	10,248	10,428
Private Generation	(197)	(220)	(242)	(265)	(287)	(309)	(330)	(352)	(374)
Existing - Demand Response	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)
New Energy Efficiency	(1,037)	(1,124)	(1,209)	(1,317)	(1,400)	(1,498)	(1,589)	(1,653)	(1,752)
East Total obligation	**7,494**	**7,523**	**7,618**	**7,649**	**7,686**	**7,679**	**7,699**	**7,749**	**7,808**
Planning Reserve Margin (13%)	974	978	990	994	999	998	1,001	1,007	1,015
East Obligation + Reserves	8,468	8,501	8,608	8,644	8,685	8,677	8,699	8,756	8,823
East Position	27	(11)	(127)	(1,679)	(2,452)	(2,456)	(3,696)	(3,860)	(3,931)
Available Market Purchases	500	500	500	500	500	500	500	500	500
West									
Thermal	736	736	736	500	500	500	500	500	500
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	699	699	699	699	699	699	699	699	707
Wind	56	56	56	56	56	56	56	56	56
Solar	52	51	51	51	51	50	50	50	48
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0
Qualifying Facilities	182	182	181	162	160	159	159	158	159
Sale	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
West Existing Resources	**1,718**	**1,718**	**1,717**	**1,461**	**1,459**	**1,457**	**1,457**	**1,456**	**1,464**
Load	4,929	4,995	5,068	5,176	5,246	5,318	5,384	5,461	5,647
Private Generation	(148)	(163)	(178)	(193)	(208)	(222)	(236)	(250)	(264)
Existing - Demand Response	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
New Energy Efficiency	(299)	(322)	(314)	(357)	(355)	(366)	(396)	(391)	(429)
West Total obligation	**4,461**	**4,489**	**4,555**	**4,605**	**4,662**	**4,709**	**4,731**	**4,799**	**4,933**
Planning Reserve Margin (13%)	580	584	592	599	606	612	615	624	641
West Obligation + Reserves	281	262	278	242	251	247	219	233	213
West Position	1,438	1,456	1,439	1,219	1,208	1,211	1,238	1,223	1,251
Available Market Purchases	500	500	500	500	500	500	500	500	500
System									
Total Resources	10,214	10,208	10,198	8,426	7,691	7,679	6,460	6,353	6,355
Obligation	11,956	12,012	12,173	12,254	12,347	12,389	12,430	12,547	12,741
Planning Reserves (13%)	1,554	1,562	1,583	1,593	1,605	1,611	1,616	1,631	1,656
Obligation + Reserves	13,510	13,574	13,756	13,848	13,952	13,999	14,045	14,179	14,398
System Position	(3,296)	(3,366)	(3,558)	(5,422)	(6,261)	(6,320)	(7,586)	(7,826)	(8,042)
Available Market Purchases	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
Net Surplus/(Deficit)	(2,296)	(2,366)	(2,558)	(4,422)	(5,261)	(5,320)	(6,586)	(6,826)	(7,042)

[3] The DSM line includes selected Class 2 DSM from the 2023 IRP Update resource portfolio.

Table 4.3 – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2023 IRP Update (2024-2033) (Megawatts) [4]

East	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Thermal	6,828	6,875	6,795	6,795	6,578	6,264	6,264	6,264	6,264	6,264
Peaker	323	323	323	323	323	323	323	323	323	0
Hydroelectric	36	36	36	36	36	36	36	36	36	36
Wind	442	602	594	594	594	594	579	552	552	552
Solar	197	288	408	405	402	399	396	393	391	388
Other Renewable	34	34	34	34	34	34	34	34	34	34
Storage	1	1	468	468	468	468	468	468	468	468
Purchase	172	172	172	172	172	172	172	172	172	172
Qualifying Facilities	284	283	281	279	278	276	275	273	271	263
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,317**	**8,613**	**9,111**	**9,107**	**8,884**	**8,566**	**8,547**	**8,515**	**8,510**	**8,177**
Load	5,724	6,097	6,171	6,444	6,754	6,700	6,872	7,145	7,214	7,387
Private Generation	(2)	0	0	0	0	(8)	(10)	0	0	0
Existing - Demand Response	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)
New Energy Efficiency	(102)	(111)	(172)	(232)	(299)	(470)	(569)	(529)	(615)	(693)
East Total obligation	**5,158**	**5,523**	**5,536**	**5,749**	**5,993**	**5,760**	**5,830**	**6,153**	**6,137**	**6,232**
Planning Reserve Margin (13%)	671	718	720	747	779	749	758	800	798	810
East Obligation + Reserves	5,829	6,241	6,256	6,496	6,772	6,508	6,588	6,953	6,934	7,042
East Position	2,488	2,372	2,855	2,610	2,112	2,058	1,958	1,563	1,575	1,135
Available Market Purchases	825	825	825	825	800	800	800	800	800	800
West										
Thermal	878	878	874	874	874	874	736	736	736	736
Peaker	0	0	0	0	0	0	0	0	0	0
Hydroelectric	538	544	542	555	556	555	555	553	554	554
Wind	74	74	74	74	74	74	74	74	74	74
Solar	44	43	43	43	42	42	42	41	40	40
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	116	127	127	127	127	126	126	126	120	120
Sale	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
West Existing Resources	**1,639**	**1,657**	**1,650**	**1,662**	**1,662**	**1,660**	**1,522**	**1,520**	**1,514**	**1,513**
Load	3,711	3,577	3,676	3,858	4,024	4,476	4,539	4,419	4,475	4,524
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
New Energy Efficiency	(89)	(96)	(126)	(167)	(221)	(324)	(378)	(341)	(368)	(415)
West Total obligation	**3,611**	**3,470**	**3,539**	**3,681**	**3,792**	**4,142**	**4,151**	**4,068**	**4,095**	**4,098**
Planning Reserve Margin (13%)	469	451	460	479	493	538	540	529	532	533
West Obligation + Reserves	4,081	3,921	3,999	4,160	4,285	4,680	4,691	4,596	4,628	4,630
West Position	(2,441)	(2,265)	(2,350)	(2,497)	(2,623)	(3,020)	(3,169)	(3,076)	(3,114)	(3,117)
Available Market Purchases	3,000	3,000	3,000	3,000	700	700	700	700	700	700
System										
Total Resources	9,956	10,270	10,761	10,769	10,547	10,226	10,069	10,035	10,024	9,690
Obligation	8,769	8,993	9,076	9,430	9,785	9,901	9,981	10,220	10,232	10,329
Planning Reserves (13%)	1,140	1,169	1,180	1,226	1,272	1,287	1,298	1,329	1,330	1,343
Obligation + Reserves	9,909	10,162	10,255	10,656	11,057	11,189	11,279	11,549	11,562	11,672
System Position	47	108	505	113	(511)	(962)	(1,210)	(1,514)	(1,538)	(1,982)

[4] The DSM line includes selected Class 2 DSM from the 2023 IRP Update resource portfolio.

Table 4.3 (cont.) – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2023 IRP Update (2034-2042) (Megawatts)[5]

East	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	6,264	6,264	6,264	4,815	4,117	4,117	2,854	2,854	2,854
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	36	36	36	36	36	36	36	36	36
Wind	552	552	552	552	552	552	552	470	470
Solar	385	383	380	357	354	352	350	347	345
Other Renewable	34	34	34	34	8	8	8	8	8
Storage	467	467	467	467	467	467	467	467	467
Purchase	172	172	172	172	172	172	172	172	172
Qualifying Facilities	259	257	254	213	212	207	206	205	204
Sale	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,169**	**8,165**	**8,159**	**6,645**	**5,918**	**5,911**	**4,645**	**4,560**	**4,556**
Load	7,329	7,518	7,607	7,745	7,870	8,007	8,186	8,326	8,472
Private Generation	(19)	(21)	(23)	(25)	(28)	(30)	(32)	(0)	(36)
Existing - Demand Response	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)	(463)
New Energy Efficiency	(1,024)	(1,147)	(1,263)	(1,464)	(1,573)	(1,658)	(1,743)	(1,868)	(2,048)
East Total obligation	**5,823**	**5,887**	**5,858**	**5,793**	**5,807**	**5,857**	**5,949**	**5,995**	**5,925**
Planning Reserve Margin (13%)	757	765	761	753	755	761	773	779	770
East Obligation + Reserves	6,580	6,652	6,619	6,546	6,562	6,618	6,722	6,774	6,695
East Position	1,590	1,513	1,540	99	(644)	(707)	(2,077)	(2,215)	(2,138)
Available Market Purchases	800	800	800	800	800	800	800	800	800
West									
Thermal	736	736	736	499	499	499	499	499	499
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	554	554	554	554	554	554	554	554	565
Wind	74	74	74	74	74	74	74	74	74
Solar	39	39	39	39	39	38	38	38	38
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1
Qualifying Facilities	120	120	119	105	104	103	103	103	103
Sale	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
West Existing Resources	**1,513**	**1,513**	**1,512**	**1,261**	**1,260**	**1,259**	**1,258**	**1,258**	**1,269**
Load	4,770	4,917	4,986	4,938	5,058	5,133	5,273	5,285	5,394
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
New Energy Efficiency	(588)	(634)	(678)	(720)	(755)	(801)	(844)	(838)	(943)
West Total obligation	**4,171**	**4,272**	**4,297**	**4,207**	**4,293**	**4,321**	**4,418**	**4,436**	**4,440**
Planning Reserve Margin (13%)	542	555	559	547	558	562	574	577	577
West Obligation + Reserves	(46)	(79)	(120)	(173)	(196)	(239)	(269)	(261)	(365)
West Position	1,559	1,591	1,632	1,433	1,456	1,498	1,528	1,519	1,634
Available Market Purchases	700	700	700	700	700	700	700	700	700
System									
Total Resources	9,683	9,678	9,671	7,906	7,178	7,169	5,903	5,818	5,825
Obligation	9,994	10,159	10,155	10,001	10,100	10,178	10,367	10,431	10,365
Planning Reserves (13%)	1,299	1,321	1,320	1,300	1,313	1,323	1,348	1,356	1,347
Obligation + Reserves	11,293	11,480	11,475	11,301	11,413	11,501	11,715	11,787	11,712
System Position	(1,611)	(1,802)	(1,803)	(3,395)	(4,235)	(4,332)	(5,811)	(5,970)	(5,887)
Available Market Purchases	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Uncommitted FOTs to meet remaining Need	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
Net Surplus/(Deficit)	(111)	(302)	(303)	(1,895)	(2,735)	(2,832)	(4,311)	(4,470)	(4,387)

[5] The DSM line includes selected Class 2 DSM from the 2023 IRP Update resource portfolio.

Figure 4.3 and Figure 4.4 are graphic representations of the above tables for the 2023 IRP Update annual capacity position for the summer system, winter system respectively. Also shown in the system capacity position graphs are the capacity contribution from uncommitted FOTs, which as discussed above, are provided for informational purposes.

Figure 4.3 – Summer System Capacity Position Trend

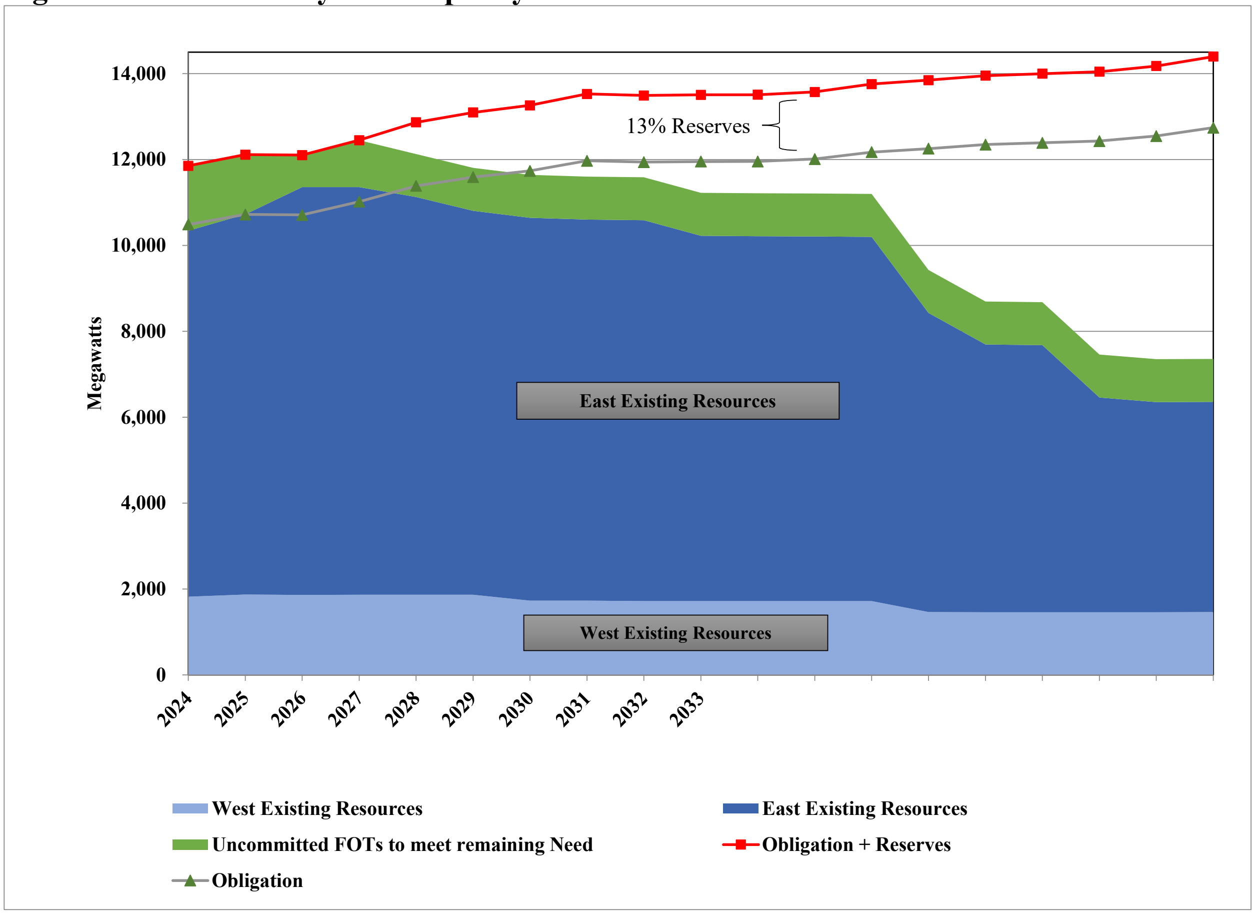
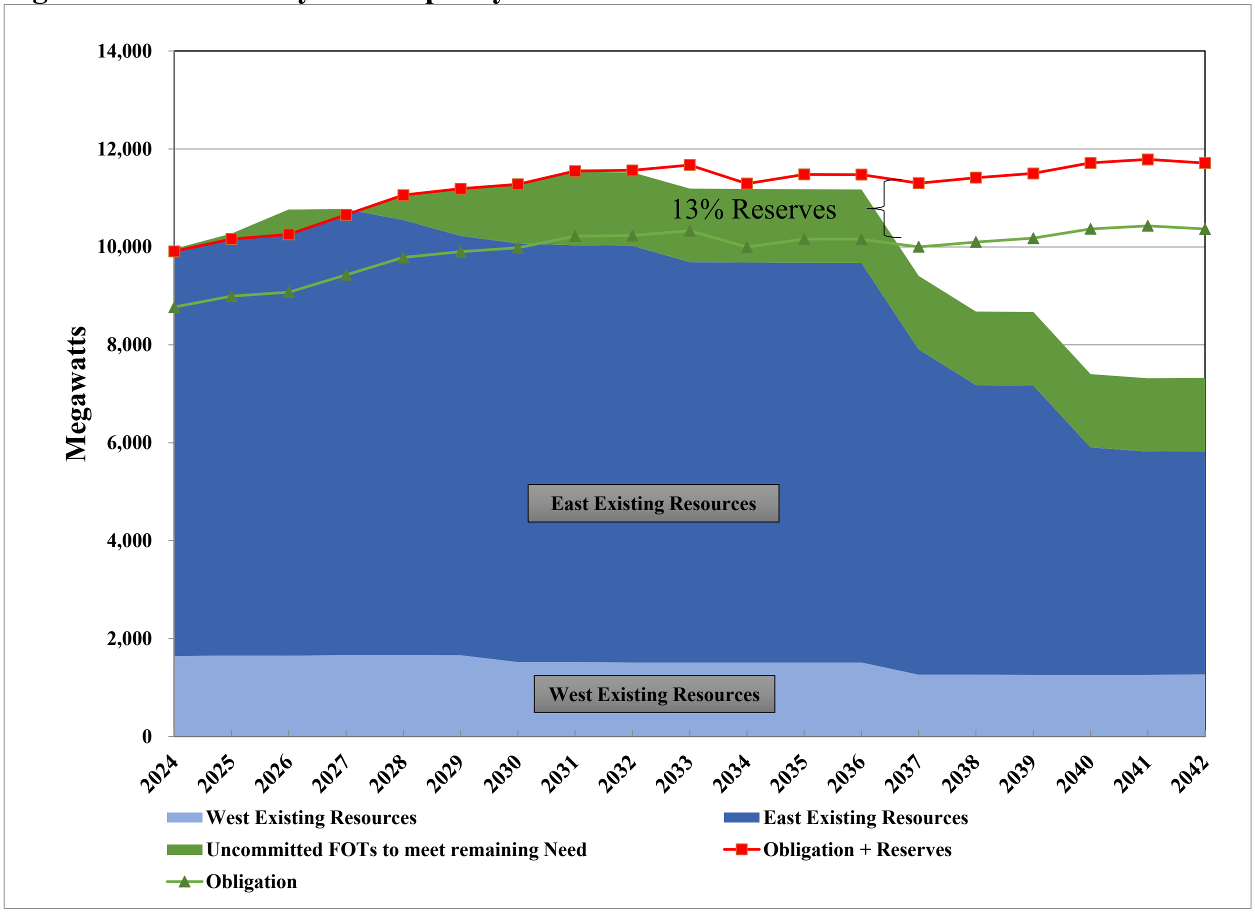


Figure 4.4 – Winter System Capacity Position Trend



CHAPTER 5 – MODELING AND ASSUMPTIONS

General Assumptions

The study period for the 2023 IRP Update is 2024-2042, with a focus on the 2024-2028 planning horizon.[1] While many assumptions are unchanged from the 2023 IRP, PacifiCorp has materially updated certain assumptions in the 2023 IRP Update as discussed below.

Inflation Rates

The 2023 IRP Update model simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.28% is assumed, consistent with the 2023 IRP. The annual escalation rate reflects the average of annual inflation rate projections for the 20-year study period, using PacifiCorp's September 2023 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for Gross Domestic Product inflator and Consumer Price Index.

Discount Factor

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 Update is 6.69%. 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.[2] Present-value revenue requirement values reported in the 2023 IRP Update are reported in 2023 dollars.

Front Office Transactions

Although PacifiCorp's understanding of likely market purchase availability is evolving with the emergence of Western Region Adequacy Program (WRAP) relationships with other utilities, as well as the expansion of regional energy markets, no added information has emerged to justify changing assumptions from the existing markets modeled in the 2023 IRP. However, for the 2023 IRP Update, PacifiCorp is now modeling additional potential for market purchases in Wyoming to reflect its increased transmission system connectivity to other utilities. Table 5.1 reports the available FOT modeling assumptions; identifying the market hub, product type, annual capacity limit, and availability associated with the product. PacifiCorp develops its front office transaction (FOT) planning limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and depth, and with consideration of regional resource supply.

[1] As year 2023 has passed into history, it is not generally reported in this 2023 IRP Update; however, some workpapers will still contain 2023 information as an artifact of developing data for the remainder of the 20-year modeling horizon.

[2] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

Table 5.1 - Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub	Availability Limit (MW)			Change from 2023 IRP	
	2023 IRP Update				
	Short-term (2023-2027)	Long-term (2028-2042)			
		Summer	Winter	Summer	Winter
Mid-Columbia (Mid-C)	1979	500	350	-	-
California Oregon Border (COB)	424	0	250	-	-
Nevada Oregon Border (NOB)	200	0	100	-	-
4 Corners (4C)	398	0	0	-	-
Mona	325	0	300	-	-
Wyoming	500	500	500	New	New
Total	**3826**	**1000**	**1500**		

Stochastic Parameters

Stochastic parameters assumed in the 2023 IRP Update are consistent with those applied in the 2023 IRP. PacifiCorp provided a detailed description of its stochastic parameters and their development in Volume II, Appendix H of the 2023 IRP – Amended Final, filed May 31, 2023.

Flexible Reserve Study

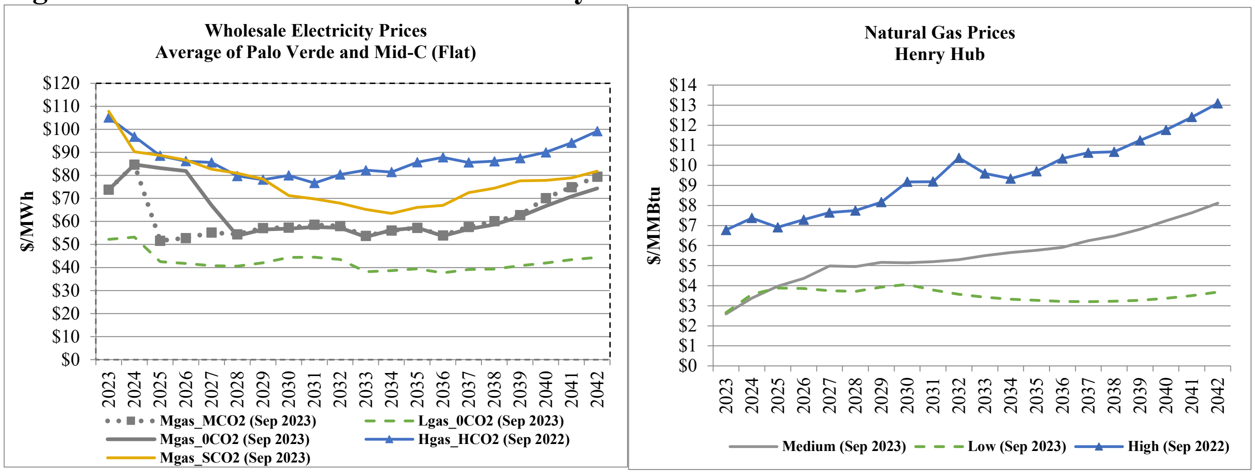
PacifiCorp applied its Flexible Reserve Study methodology from the 2023 IRP in its 2023 IRP Update. PacifiCorp provided a detailed description of its Flexible Reserve Study in Volume II, Appendix F of the 2023 IRP.

Natural Gas and Power Market Price Updates

Portfolio modeling for the 2023 IRP Update was prepared using five market price forecasts. This includes the official forward price curve (OFPC) and four scenarios.

Figure 5.1 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and variant studies for the 2023 IRP Update. Power prices are higher in the near term. All five power price scenarios trend higher beginning in different years in the forecast but escalate at different increasing rates. Natural gas prices start low then grow at different escalation rates depending on the scenario.

Figure 5.1 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



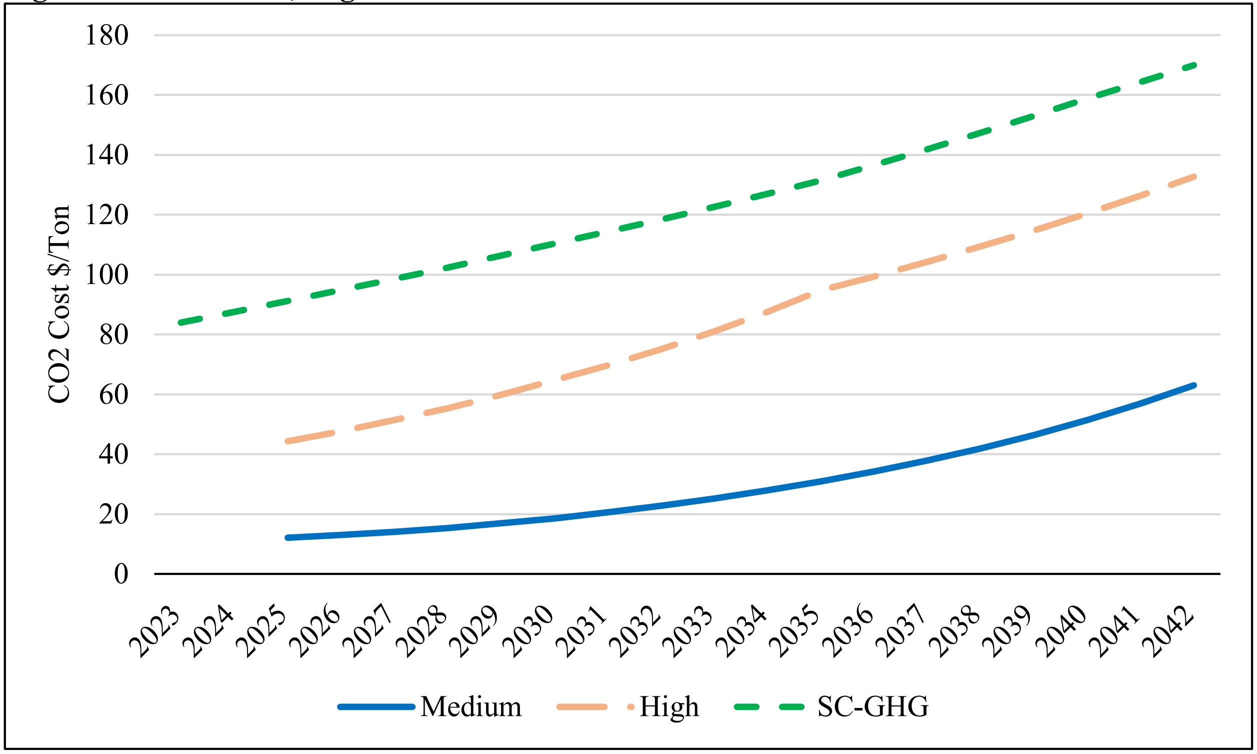
PacifiCorp's September 30, 2023, OFPC is used to represent medium natural gas price assumptions with no CO_2 prices for the "MN" price-policy scenario. OFPCs are produced for both natural gas and power prices by point of delivery. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflect market forwards at the close of a given trading day.[3] As such, these 36 months are market forwards as of September 2023. 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 fundamental portion of the electricity OFPC reflects prices as forecast by AURORAxmp[4] (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 in this quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Carbon Dioxide Emission Policy

Consistent with the 2023 IRP, PacifiCorp used four different CO_2 price scenarios in the 2023 IRP Update—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The modeled CO_2 price scenarios are *not* intended to explicitly account for a future monetary tax on CO_2 emissions. Instead, these costs capture the trend of federal policies that incentivize reduced emissions through benefits (i.e., production tax credits) or impose restrictions or costs or other market dynamics that drive the need for zero-emission resources and the relative ability for such resources to be developed and procured. Such scenarios reflect the reality of the current federal regulatory landscape, as illustrated in Chapter 3, and ensure that the PacifiCorp's preferred portfolio is least-cost for its customers over time. This treatment further allows the IRP analysis to examine the costs, risks and robustness of portfolios when viewed under a range of futures. Figure 5.2 illustrates the CO_2 proxy price curves used in the 2023 IRP Update.

[3] The September 2023 OFPC prompt month is November 2023; October 2023 would be traded as "balance of month" when the OFPC is released.
[4] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

Figure 5.2 – Medium, High and Social Cost of Greenhouse Gas CO_2 Prices



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 proxy price beginning 2025.

PacifiCorp also incorporated the social cost of greenhouse gas in compliance with Washington Revised Code of Washington 19.280.030. The 2023 IRP Update 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 (SC-GHG) is assumed to apply in all years of the study horizon. The SC-GHG 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's suggested treatment, in SC-GHG studies, 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

[5] Washington Utilities and Transportation Commission, Order 04, Docket No. U-190730, July 27, 2023

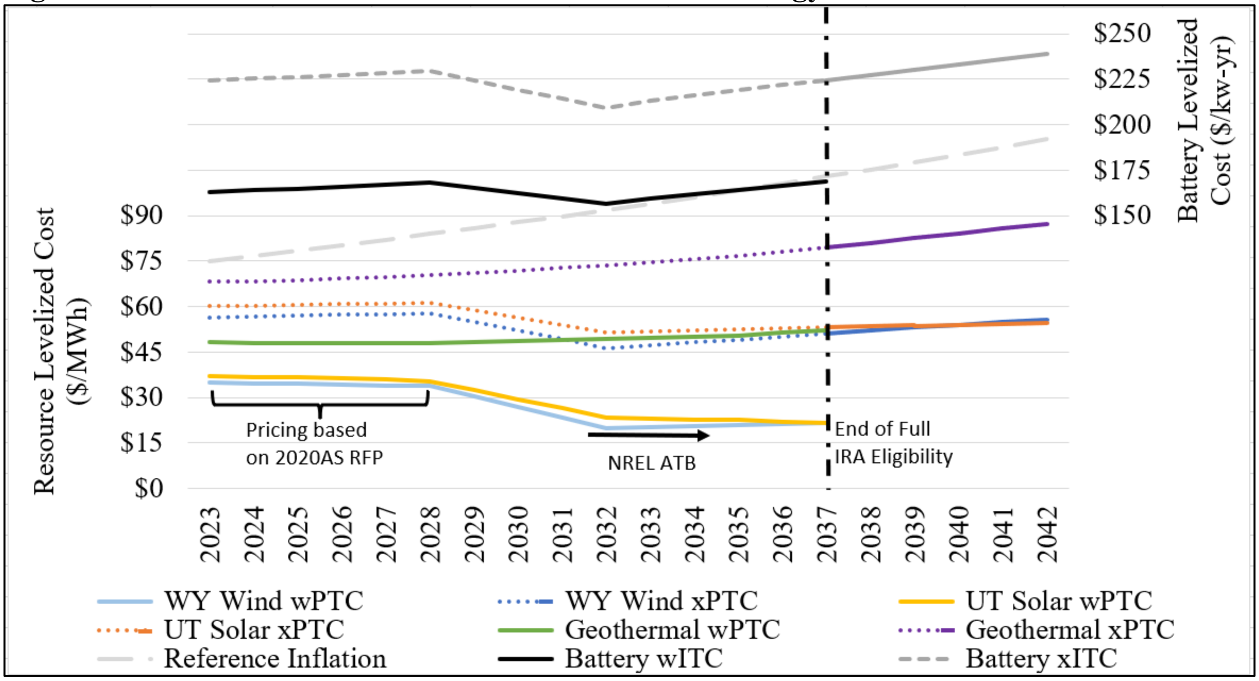
by the Washington Legislature in 2021. This is in addition to the assumed federal CO2 policy represented in the zero, medium, high, and social cost of greenhouse gas scenarios described above. The modeled allowance cost reflects analysis conducted by Vivid Economics for the Washington Department of Ecology and starts at $58 per ton in 2023.

Supply-Side Resources

Proxy resource costs and operating characteristics are generally unchanged from assumptions used in the 2023 IRP. However, in response to stakeholder comments, PacifiCorp incorporated a modified cost-escalation rate for geothermal resources based on the National Renewable Energy Laboratory's 2023 Annual Technology Baseline. Whereas geothermal costs were previously modeled as escalating at inflation, the updated escalation rate results in lower costs throughout the study horizon. As a result, geothermal joins wind, solar, and lithium-ion battery storage in using resource cost escalation rates that are lower than the standard estimate based on inflation, though near-term wind and solar costs are aligned with recent offers with bidders in PacifiCorp's 2020 All-Source Request for Proposals, from summer 2022. In conjunction with tax credits, this results in variation in costs over time, as presented in Figure 5.3.

Several modifications were made to clarify the assumptions within the supply-side resource table. Hydrogen resources were split out to report whether they use hydrogen on-site storage or pipeline supply. Inflation Reduction Act (IRA) credits were included in the 2023 IRP and have now been identified for each resource type within the supply-side table below for the 2023 IRP Update. Within the supply-side table detail, all costs remain in real levelized 2022 dollars. As in the 2023 IRP, near term resource selections in the 2023 IRP update are limited through 2028 to technology types and locations of pending requests that have received interconnection study results. Starting in 2029, proxy resources can be selected in any size and combination at any location, with hourly generation limited by available transmission. As an example, if a selected transmission upgrade allows for 400 additional megawatts of resources, the model is allowed to select 600 megawatts of wind resources, 300 megawatts of battery resources, 300 megawatts of solar resources, and 200 megawatts of gas peaking resources. This would cause the location to have 1400 megawatts of nameplate resources, of which only 400 megawatts could be generating into the system at any point in time. Any excess generation could flow into storage resources or would otherwise be curtailed.

Figure 5.3 – Inflation Reduction Act and Future Technology Costs



Natural Gas

In the 2023 IRP proxy natural gas plants were given an assumed economic life of 10 years, reflecting the risk that plants fueled by natural gas could have future policies limiting their effective use. In the 2023 IRP Update, given that new natural gas plants are assumed capable of converting to alternative fuels such as green hydrogen in the future, PacifiCorp is now modeling these resources using their full economic and technical lives. Manufacturers have confirmed this as a supportable assumption. The risk of early closures and derates due to emissions is mitigated by the ability to switch to non-emitting fueling in the future.

Peaking Type Resources

Related to the natural gas discussion, above, in the 2023 IRP new proxy peaking units were assumed to be non-emitting. In the 2023 IRP Update, peaking units will be selected on the basis of natural gas fueling assumptions but will have the ability to convert to hydrogen or other renewable fuel.

Demand Side Management

PacifiCorp evaluates new demand side management (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. The optimal determination of DSM resources therefore results in the selection of cost-effective DSM as a core function of IRP modeling. As in the 2023 IRP, DSM for Washington in the 2023 IRP Update preferred portfolio reflects selections from the Washington compliance scenario, under SC-GHG price-policy assumptions. In the 2023 IRP Update, energy efficiency shapes for heating and cooling measures have been updated to align with updated load, representing the relative effectiveness of these bundles to meet system need.

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Table 5.2 - 2023 IRP Update Supply Side Resources (2022$)

Information Presented is Illustrative

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	$ 34.67	$ 0.28	$ 18.68	9241	0.7	2.0	23	0.0014	0.0910	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1	0	354	2027	40	$ 814	$ 20.80	$ 2.32	$ 14.09	9073	5.6	7.2	0	0.0020	0.0570	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	0	337	2028	40	$ 3,932	$ 28.22	$ 2.44	$ 44.80	9191	5.6	7.2	122	0.0018	0.0550	0.1785	112.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	0	362	2035	40	$ 6,588	$ 31.32	$ 2.23	$ 69.00	9489	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - pipeline Willamette Valley	0	362	2035	40	$ 930	$ 31.32	$ 2.23	$ 14.09	9489	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - pipeline McNary	0	362	2035	40	$ 930	$ 31.32	$ 2.23	$ 14.09	9489	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	0	362	2033	40	$ 5,894	$ 31.32	$ 2.27	$ 66.37	9489	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	0	548	2028	40	$ 1,361	$ 20.97	$ 1.61	$ 22.72	6227	5.6	7.2	8	0.0020	0.0076	0.2550	118.9000
Natural Gas	CCCT Dry "J", DF, 1x1	0	63	2028	40	$ -	$ -	$ 1.15	$ -	8726	5.6	7.2	8	0.0020	0.0076	0.2550	118.9000
Natural Gas	SCCT Aero x4	1,500	216	2027	30	$ 1,619	$ 45.80	$ 0.30	$ 19.77	9258	0.7	2.0	24	0.0014	0.0910	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1	1,500	338	2027	40	$ 853	$ 28.29	$ 2.43	$ 14.76	9066	5.6	7.2	0	0.0020	0.0570	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	1,500	322	2028	40	$ 4,118	$ 37.95	$ 2.55	$ 46.92	9184	5.6	7.2	122	0.0018	0.0550	0.1785	113.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	1,500	345	2035	40	$ 6,903	$ 41.21	$ 2.38	$ 73.77	9481	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - pipeline Southern OR	1,500	345	2035	40	$ 975	$ 41.21	$ 2.38	$ 14.76	9481	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	1,500	345	2033	40	$ 6,176	$ 41.21	$ 2.38	$ 69.54	9481	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	1,500	523	2028	40	$ 1,427	$ 27.74	$ 1.68	$ 23.81	6227	5.6	7.2	8	0.0020	0.0076	0.2550	118.9000
Natural Gas	CCCT Dry "J", DF, 1x1	1,500	63	2028	40	$ -	$ -	$ 1.15	$ -	8688	5.6	7.2	9	0.0020	0.0076	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	3,000	305	2027	40	$ 4,355	$ 37.87	$ 2.70	$ 49.63	9189	5.6	7.2	122	0.0018	0.0550	0.1785	113.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	3,000	327	2034	40	$ 7,297	$ 42.56	$ 2.52	$ 77.98	9486	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	3,000	327	2034	40	$ 6,529	$ 42.56	$ 2.52	$ 73.52	9486	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	3,000	495	2027	40	$ 1,507	$ 27.37	$ 1.78	$ 25.15	6226	5.6	7.2	8	0.0020	0.0076	0.2550	118.9000
Natural Gas	CCCT Dry "J", DF, 1x1	3,000	63	2028	40	$ -	$ -	$ 1.15	$ -	8705	5.6	7.2	9	0.0020	0.0076	0.2550	118.9000
Natural Gas	SCCT Aero x4	5,050	190	2028	30	$ 1,844	$ 41.83	$ 0.34	$ 22.54	9326	0.7	2.0	28	0.0014	0.0914	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1	5,050	296	2029	40	$ 971	$ 24.85	$ 2.78	$ 16.83	9080	5.6	7.2	0	0.0020	0.0571	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	5,050	282	2029	40	$ 4,696	$ 33.72	$ 2.91	$ 53.53	9197	5.6	7.2	122	0.0018	0.0550	0.1785	112.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	5,050	303	2035	40	$ 7,869	$ 37.42	$ 2.72	$ 84.10	9493	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2 - pipeline Utah North	5,050	303	2035	40	$ 1,109	$ 37.42	$ 2.72	$ 16.83	9493	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	5,050	303	2035	40	$ 7,041	$ 37.42	$ 2.72	$ 79.29	9493	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - pipeline Dave Johnston	5,050	303	2035	40	$ 1,109	$ 37.42	$ 2.72	$ 16.83	9493	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - pipeline Hunter	5,050	303	2035	40	$ 1,109	$ 37.42	$ 2.72	$ 16.83	9493	5.6	7.2	406	0.0000	0.0655	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	5,050	459	2029	40	$ 1,625	$ 25.05	$ 1.92	$ 27.13	6234	5.6	7.2	8	0.0019	0.0076	0.2550	118.9000
Natural Gas	CCCT Dry "J", DF, 1x1	5,050	63	2029	40	$ -	$ -	$ 1.15	$ -	8652	5.6	7.2	9	0.0020	0.0076	0.2550	118.9000
Natural Gas	SCCT Aero x4	6,500	171	2028	30	$ 2,044	$ 49.31	$ 0.38	$ 24.98	9208	0.7	2.0	30	0.0000	0.0913	0.2550	118.9000
Natural Gas	SCCT Frame "J" x1	6,500	283	2028	40	$ 1,017	$ 28.64	$ 2.91	$ 17.63	9076	5.6	7.2	0	0.0000	0.0571	0.2550	118.9000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	6,500	289	2034	40	$ 7,374	$ 44.16	$ 2.84	$ 17.63	9489	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - pipeline Naughton	6,500	289	2034	40	$ 1,162	$ 44.16	$ 2.84	$ 17.63	9489	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	SCCT Frame "J" X1, 100H2, BF - pipeline Jim Bridger	6,500	289	2034	40	$ 1,162	$ 44.16	$ 2.84	$ 17.63	9489	5.6	7.2	406	0.0000	0.0654	0.0000	0.0000
Natural Gas	CCCT Dry "J", 1X1	6,500	437	2027	40	$ 1,704	$ 43.32	$ 2.01	$ 28.46	6241	5.6	7.2	8	0.0000	0.0076	0.2550	118.9000
Natural Gas	CCCT Dry "J", DF, 1x1	6,500	63	2027	40	$ -	$ -	$ 1.15	$ -	8590	5.6	7.2	9	0.0000	0.0076	0.2550	118.9000
Coal	PC CCUS Oxy-Combustion retrofit @ 100 MW pre-retrofit basis	5,000	-39	2028	30	$ 4,673	$ 37.00	$ 18.68	$ 54.24	18321	5	5.0	193	0.0040	0.0420	1.2000	6.2400
Coal	PC CCUS retrofit @ 330 MW pre-retrofit basis	6,500	-99	2028	20	$ 2,826	$ 37.00	$ 21.70	$ 32.71	15632	5	5.0	450	0.0050	0.0700	1.2000	20.5352
Coal	PC CCUS retrofit @ 700 MW pre-retrofit basis	6,500	-187	2028	20	$ 1,932	$ 37.00	$ 20.79	$ 18.04	14656	5	5.0	450	0.0050	0.0700	1.2000	20.5352
Storage	Li-Ion, 4-hour, 200 MW	N/A	200	2025	20	$ 1,827	$ 24.00	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	$ 1,495	$ 24.00	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	$ 1,785	$ 24.00	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	$ 1,468	$ 24.00	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	$ 1,738	$ 24.00	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	$ 1,430	$ 24.00	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	$ 2,472	$ 34.00	$ 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	$ 2,071	$ 34.00	$ -	$ 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	$ 2,294	$ 32.00	$ 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	$ 1,902	$ 32.00	$ -	$ 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	$ 3,493	$ 0.30	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	$ 1,904	$ 0.30	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	$ 3,267	$ 0.24	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	$ 1,705	$ 0.24	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	$ 2,037	$ 0.18	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	$ 993	$ 0.18	Included	$ -	n/a	0	0.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, RESC, 125 MW, 1000 MWh	6,500	125	2026	30	$ 2,322	$ 49.31	$ 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	6,500	125	2026	30	$ 2,343	$ 49.31	$ 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	6,500	125	2027	30	$ 2,588	$ 49.31	$ 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	6,500	125	2027	30	$ 2,673	$ 49.31	$ 1.05	$ 17.07	n/a	0.011	0.0	n/a	0.0000	0.0000	0.0000	0.0000

Table 5.2 - 2023 IRP Update Supply Side Resources (2022 $) (Continued)

Information Presented is Illustrative

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	6,500	125	2027	30	$ 2,869	$ 49.31	$ 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	6,500	125	2029	30	$ 3,887	$ 49.31	$ 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	6,500	250	2028	30	$ 2,453	$ 49.31	$ 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	6,500	250	2029	30	$ 2,748	$ 49.31	$ 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	6,500	250	2032	30	$ 3,678	$ 49.31	$ 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	6,500	500	2028	30	$ 2,024	$ 49.31	$ 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	6,500	500	2028	30	$ 2,037	$ 49.31	$ 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	6,500	500	2029	30	$ 2,180	$ 49.31	$ 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	6,500	500	2030	30	$ 2,327	$ 49.31	$ 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	6,500	500	2032	30	$ 2,645	$ 49.31	$ 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	6,500	500	2035	30	$ 3,629	$ 49.31	$ 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	$ 485.00	$ 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	$ 485.00	$ 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	$ 485.00	$ 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	$ 485.00	$ 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	$ 485.00	$ 0.51	$ 18.00	1	2	4.0	n/a	0.0000	0.0000	0.0000	0.0000
Storage	100-hour Iron Air Battery, max CF: 17%	N/A	200	2025	20	$ 5,367	$ 160.00	Included	$ 20.77	0	0	0.0	0	0.0000	0.0000	0.0000	0.0000
Solar	Solar - Idaho Falls, ID, 20 MW, 26.1% CF	4,700	20	2025	25	$ 1,427	$ 29.40	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar - Lakeview, OR, 20 MW, 27.6% CF	4,800	20	2023	25	$ 1,527	$ 31.50	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar - Milford, UT, 20 MW, 30.2% CF	5,000	20	2023	25	$ 1,412	$ 29.10	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar - Milford, UT, 200 MW, 30.2% CF	5,000	200	2023	25	$ 1,140	$ 29.10	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar - Rock Springs, WY, 200 MW, 27.9% CF	6,400	200	2023	25	$ 1,187	$ 30.30	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar	Solar - Yakima, WA, 200 MW, 24.2% CF	1,000	200	2025	25	$ 1,211	$ 30.90	$ -	$ 20.87	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Solar + Storage - Idaho Falls, ID, 200 MW, 26.1% CF + BESS: 100% pwr, 4 hours	4,700	200	2025	25	$ 2,879	$ 54.06	$ -	$ 63.19	1	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Solar + Storage - Lakeview, OR, 200 MW, 27.6% CF + BESS: 100% pwr, 4 hours	4,800	200	2025	25	$ 2,864	$ 56.16	$ -	$ 63.19	1	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Solar + Storage - Milford, UT, 200 MW, 30.2% CF + BESS: 100% pwr, 4 hours	5,000	200	2025	25	$ 2,881	$ 53.76	$ -	$ 63.19	1	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Solar + Storage - Rock Springs, WY, 200 MW, 27.9% CF + BESS: 100% pwr, 4 hours	6,400	200	2025	25	$ 2,902	$ 54.96	$ -	$ 63.19	1	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Solar + Storage - Yakima, WA, 200 MW, 24.2% CF + BESS: 100% pwr, 4 hours	1,000	200	2025	25	$ 2,977	$ 55.56	$ -	$ 63.19	1	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Pocatello, ID, 20 MW, CF: 37.1%	4,500	20	2026	30	$ 2,161	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Pocatello, ID, 200 MW, CF: 37.1%	4,500	200	2026	30	$ 1,597	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Arlington, OR, 20 MW, CF: 37.1%	1,500	20	2026	30	$ 2,149	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Arlington, OR, 200 MW, CF: 37.1%	1,500	200	2026	30	$ 1,567	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Monticello, UT, 20 MW, CF: 29.5%	4,500	20	2026	30	$ 2,186	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Monticello, UT, 200 MW, CF: 29.5%	4,500	200	2026	30	$ 1,626	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Medicine Bow, WY, 20 MW, CF: 43.6%	6,500	20	2026	30	$ 2,129	$ 59.46	$ -	$ 43.00	n/a	Included with CF	0.0	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Medicine Bow, WY, 200 MW, CF: 43.6%	6,500	200	2026	30	$ 1,568	$ 59.46	$ -	$ 43.00	n/a	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Goldendale, WA, 20 MW, CF: 37.1%	1,500	20	2026	30	$ 2,274	$ 59.46	$ -	$ 43.00	n/a	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Goldendale, WA, 200 MW, CF: 37.1%	1,500	200	2026	30	$ 1,660	$ 59.46	$ -	$ 43.00	n/a	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind - Offshore, Northern, CA, CF: 47.0%	0	200	2028	30	$ 4,636	$ 158.23	$ -	$ 103.00	n/a	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind -Offshore, Northern, CA, 1GW, CF: 47.0%	0	1,000	2028	30	$ 4,633	$ 158.23	$ -	$ 103.00	n/a	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Pocatello, ID, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	4,500	200	2026	30	$ 3,290	$ 83.46	$ -	$ 85.32	1	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Arlington, OR, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	200	2026	30	$ 3,166	$ 83.46	$ -	$ 85.32	1	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Monticello, UT, 200 MW, CF: 29.5% + BESS: 100% pwr, 4 hours	4,500	200	2026	30	$ 3,332	$ 83.46	$ -	$ 85.32	1	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 100% pwr, 4 hours	6,500	200	2026	30	$ 3,252	$ 83.46	$ -	$ 85.32	1	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Goldendale, WA, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	200	2026	30	$ 3,389	$ 83.46	$ -	$ 85.32	1	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Wind + Storage - Offshore, Northern, CA, CF: 47.0% + BESS: 100% pwr, 4 hours	0	200	2028	30	$ 6,545	$ 182.23	$ -	$ 145.32	85%	Included with CF	Included with CF	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	$ 6,194	$ 113.52	$ -	$ 148.51	85%	Included with CF	Included with CF	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	$ 115.62	$ -	$ 148.51	85%	Included with CF	Included with CF	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	$ 113.22	$ -	$ 148.51	85%	Included with CF	Included with CF	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	$ 114.42	$ -	$ 148.51	85%	Included with CF	Included with CF	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	$ 115.02	$ -	$ 148.51	85%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Geothermal	Geothermal - Dual Flash Expansion of Blundell Plant	4,500	200	2026	40	$ 3,835	$ 117.00	$ -	$ 115.00	n/a	2.5	2.5	1,453.4	n/a	n/a	n/a	n/a
Geothermal	Geothermal - Greenfield Binary Plant	4,500	200	2026	40	$ 5,568	$ 117.00	$ -	$ 115.00	n/a	2.5	2.5	1,453.4	n/a	n/a	n/a	n/a
Nuclear	Nuclear - Advanced LWR, 600 MW Site	N/A	600	2032	60	$ 8,416	$ 721.53	$ -	$ 170.60	N/A	1.0	4.0	767.2	0.0000	0.0000	0.0000	0.0000
Nuclear	Nuclear - Advanced LWR, 1200 MW Site	N/A	1,200	2032	60	$ 7,272	$ 721.53	$ -	$ 152.29	N/A	1.0	4.0	767.2	0.0000	0.0000	0.0000	0.0000
Nuclear	Advanced Nuclear Reactor (AR), dual unit, with Thermal Storage (1000 Mwe interconnection with 1705 MWh Storage, 638 MW initial base generation)	N/A	638	2032	60	$ 8,772	$ 721.53	$ -	$ 472.81	N/A	3.0	5.0	767.2	0.0000	0.0000	0.0000	0.0000
Nuclear	Advanced Nuclear Reactor (AR) with improved fuel (1000 Mwe interconnection with 1705 MWh Storage, 690 MW base generation)	N/A	690	2038	Aligned with original plant	$ 8,772	$ 721.53	$ -	$ 286.40	N/A	2.0	4.0	767.2	0.0000	0.0000	0.0000	0.0000

Iron Air battery presented with most recent costs that have not flowed into the PLEXOS model

Table 5.3 – 2023 IRP Update Supply Side Resources (2022 $)

Information Presented is Illustrative

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	$31.59	$50.27	$161.95
SCCT Frame "J" x1	No	0	$814	$21	6.456%	$53.89	$14.09	0.000%	$0.00	$31.02	$45.11	$99.00
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	No	0	$3,932	$28	6.456%	$255.67	$44.80	0.000%	$0.00	$31.42	$76.22	$331.89
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	No	0	$6,588	$31	6.456%	$427.34	$69.00	0.000%	$0.00	$32.44	$101.44	$528.77
SCCT Frame "J" X1, 100H2 - pipeline Willamette Valley	Yes	0	$930	$31	6.456%	$62.04	$14.09	0.000%	$0.00	$119.30	$133.39	$195.43
SCCT Frame "J" X1, 100H2 - pipeline McNary	Yes	0	$930	$31	6.456%	$62.04	$14.09	0.000%	$0.00	$266.68	$280.77	$342.81
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	No	0	$5,894	$31	6.456%	$382.59	$66.37	0.000%	$0.00	$32.44	$98.80	$481.39
CCCT Dry "J", 1X1	No	0	$1,361	$21	6.609%	$91.33	$22.72	2.616%	$0.59	$21.29	$44.60	$135.93
CCCT Dry "J", DF, 1x1	No	0	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$29.83	$29.83	$29.83
SCCT Aero x4	No	1,500	$1,619	$46	7.140%	$118.87	$19.77	0.000%	$0.00	$31.65	$51.42	$170.29
SCCT Frame "J" x1	No	1,500	$853	$28	6.456%	$56.89	$14.76	0.000%	$0.00	$30.99	$45.75	$102.64
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	No	1,500	$4,118	$38	6.456%	$268.33	$46.92	0.000%	$0.00	$31.39	$78.32	$346.64
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	No	1,500	$6,903	$41	6.456%	$448.32	$73.77	0.000%	$0.00	$32.41	$106.17	$554.49
SCCT Frame "J" X1, 100H2 - pipeline Southern OR	Yes	1,500	$975	$41	6.456%	$65.59	$14.76	0.000%	$0.00	$119.19	$133.96	$199.54
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	No	1,500	$6,176	$41	6.456%	$401.43	$69.54	0.000%	$0.00	$32.41	$101.95	$503.38
CCCT Dry "J", 1X1	No	1,500	$1,427	$28	6.609%	$96.11	$23.81	2.616%	$0.62	$21.29	$45.72	$141.84
CCCT Dry "J", DF, 1x1	No	1,500	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$29.70	$29.70	$29.70
SCCT Aero x4	No	3,000	$1,712	$46	7.140%	$125.56	$20.92	0.000%	$0.00	$14.21	$35.12	$160.69
SCCT Frame "J" x1	No	3,000	$901	$29	6.456%	$60.06	$15.61	0.000%	$0.00	$13.88	$29.48	$89.54
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	No	3,000	$4,355	$38	6.456%	$283.62	$49.63	0.000%	$0.00	$14.06	$63.68	$347.31
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	No	3,000	$7,297	$43	6.456%	$473.86	$77.98	0.000%	$0.00	$14.51	$92.49	$566.35
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	No	3,000	$6,529	$43	6.456%	$424.29	$73.52	0.000%	$0.00	$14.51	$88.03	$512.32
CCCT Dry "J", 1X1	No	3,000	$1,507	$27	6.609%	$101.38	$25.15	2.616%	$0.66	$9.52	$35.34	$136.71
CCCT Dry "J", DF, 1x1	No	3,000	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$13.32	$13.32	$13.32
SCCT Aero x4	Yes	5,050	$1,844	$42	7.140%	$134.64	$22.54	0.000%	$0.00	$14.20	$36.74	$171.39
SCCT Frame "J" x1	Yes	5,050	$971	$25	6.456%	$64.31	$16.83	0.000%	$0.00	$13.83	$30.66	$94.97
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	No	5,050	$4,696	$34	6.456%	$305.37	$53.53	0.000%	$0.00	$14.01	$67.53	$372.90
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	Yes	5,050	$7,869	$37	6.456%	$510.43	$84.10	0.000%	$0.00	$14.46	$98.56	$608.99
SCCT Frame "J" X1, 100H2 - pipeline Utah North	Yes	5,050	$1,109	$37	6.456%	$74.03	$16.83	0.000%	$0.00	$118.83	$135.66	$209.69
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	No	5,050	$7,041	$37	6.456%	$456.98	$79.29	0.000%	$0.00	$14.46	$93.74	$550.72
SCCT Frame "J" X1, 100H2, BF - pipeline Dave Johnston	Yes	5,050	$1,109	$37	6.456%	$74.03	$16.83	0.000%	$0.00	$209.67	$226.51	$300.54
SCCT Frame "J" X1, 100H2, BF - pipeline Hunter	Yes	5,050	$1,109	$37	6.456%	$74.03	$16.83	0.000%	$0.00	$39.61	$56.44	$130.47
CCCT Dry "J", 1X1	Yes	5,050	$1,625	$25	6.609%	$109.01	$27.13	2.616%	$0.71	$9.49	$37.34	$146.35
CCCT Dry "J", DF, 1x1	Yes	5,050	$0	$0	6.609%	$0.00	$0.00	2.616%	$0.00	$13.18	$13.18	$13.18
SCCT Aero x4	Yes	6,500	$2,044	$49	7.140%	$149.43	$24.98	0.000%	$0.00	$24.74	$49.73	$199.16
SCCT Frame "J" x1	Yes	6,500	$1,017	$29	6.456%	$67.52	$17.63	0.000%	$0.00	$24.39	$42.02	$109.53
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	No	6,500	$4,918	$40	6.456%	$320.07	$56.05	0.000%	$0.00	$24.70	$80.76	$400.83
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	Yes	6,500	$8,241	$44	6.456%	$534.94	$88.09	0.000%	$0.00	$25.50	$113.59	$648.53
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	No	6,500	$7,374	$44	6.456%	$479	$83.04	0.000%	$0.00	$25.50	$108.54	$587.50
SCCT Frame "J" X1, 100H2, BF - pipeline Naughton	Yes	6,500	$1,162	$44	6.456%	$77.86	$17.63	0.000%	$0.00	$118.77	$136.40	$214.26
SCCT Frame "J" X1, 100H2, BF - pipeline Jim Bridger	Yes	6,500	$1,162	$44	6.456%	$77.86	$17.63	0.000%	$0.00	$175.80	$193.43	$271.30
CCCT Dry "J", 1X1	Yes	6,500	$1,704	$43	6.609%	$115	$28.46	2.616%	$0.74	$16.77	$45.98	$161.46
CCCT Dry "J", DF, 1x1	Yes	6,500	$0	$0	6.609%	$0	$0.00	2.616%	$0.00	$23.08	$23.08	$23.08

Table 5.3 – 2023 IRP Update Supply Side Resources (2022 $) (Continued)

Information Presented is Illustrative

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 Oxy-Combustion retrofit @ 100 MW pre-retrofit basis	Yes	5,000	$4,673	$37	7.289%	$343.30	$54.24	5.541%	$3.01	$0.00	$57.25	$400.54
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	$1,827	$24	8.405%	$155.59	$42.32	0.000%	$0.00	$0.00	$42.32	$197.91
Incremental, double energy capacity (L-ion, 4hr, 200MW)	No	N/A	$1,495	$24	8.405%	$127.65	$42.32	0.000%	$0.00	$0.00	$42.32	$169.97
Li-Ion, 4-hour, 500 MW	Yes	N/A	$1,785	$24	8.405%	$152.01	$41.36	0.000%	$0.00	$0.00	$41.36	$193.37
Incremental, double energy capacity (L-ion, 4hr, 500MW)	Yes	N/A	$1,468	$24	8.405%	$125.39	$41.36	0.000%	$0.00	$0.00	$41.36	$166.75
Li-Ion, 4-hour, 1000 MW	No	N/A	$1,738	$24	8.405%	$148.12	$40.31	0.000%	$0.00	$0.00	$40.31	$188.43
Incremental, double energy capacity (L-ion, 4hr, 1000MW)	No	N/A	$1,430	$24	8.405%	$122.21	$40.31	0.000%	$0.00	$0.00	$40.31	$162.52
Flow Battery, 4 hour, 200 MW	Yes	N/A	$2,472	$34	8.405%	$210.62	$64.27	0.000%	$0.00	$0.00	$64.27	$274.89
Incremental, double energy capacity (Flow, 4hr, 200MW)	Yes	N/A	$2,071	$34	8.405%	$176.94	$7.00	0.000%	$0.00	$0.00	$7.00	$183.94
Flow Battery, 4 hour, 1000 MW	No	N/A	$2,294	$32	8.405%	$195.51	$54.86	0.000%	$0.00	$0.00	$54.86	$250.38
Incremental, double energy capacity (Flow, 4hr, 1000MW)	Yes	N/A	$1,902	$32	8.405%	$162.56	$1.66	0.000%	$0.00	$0.00	$1.66	$164.22
Gravity Battery, 4 hour,	Yes	N/A	$3,493	$0	8.405%	$293.64	$80.97	0.000%	$0.00	$0.00	$80.97	$374.61
Incremental, double energy capacity (Gravity, 4hr, 200MW)	Yes	N/A	$1,904	$0	8.405%	$160.09	$0.00	0.000%	$0.00	$0.00	$0.00	$160.09
Gravity Battery, 4 hour,	Yes	N/A	$3,267	$0	8.405%	$274.61	$75.75	0.000%	$0.00	$0.00	$75.75	$350.36
Incremental, double energy capacity (Gravity, 4hr, 500MW)	Yes	N/A	$1,705	$0	8.405%	$143.32	$0.00	0.000%	$0.00	$0.00	$0.00	$143.32
Gravity Battery, 4 hour,	Yes	N/A	$2,037	$0	8.405%	$171.26	$47.25	0.000%	$0.00	$0.00	$47.25	$218.51
Incremental, double energy capacity (Gravity, 4hr, 1000MW)	No	N/A	$993	$0	8.405%	$83.51	$0.00	0.000%	$0.00	$0.00	$0.00	$83.51
Adiabatic CAES, RESC, 125 MW, 1000 MWh	No	6,500	$2,322	$49	6.804%	$161.34	$16.91	5.480%	$0.93	$0.00	$17.84	$179.17
Adiabatic CAES, RESC, 125 MW, 1250 MWh	No	6,500	$2,343	$49	6.804%	$162.80	$16.95	5.480%	$0.93	$0.00	$17.88	$180.68
Adiabatic CAES, RESC, 125 MW, 1500 MWh	No	6,500	$2,588	$49	6.804%	$179.44	$16.99	5.480%	$0.93	$0.00	$17.92	$197.36
Adiabatic CAES, RESC, 125 MW, 2000 MWh	No	6,500	$2,673	$49	6.804%	$185.25	$17.07	5.480%	$0.94	$0.00	$18.01	$203.26
Adiabatic CAES, RESC, 125 MW, 3000 MWh	No	6,500	$2,869	$49	6.804%	$198.54	$17.23	5.480%	$0.94	$0.00	$18.18	$216.72
Adiabatic CAES, RESC, 125 MW, 6000 MWh	No	6,500	$3,887	$49	6.804%	$267.81	$17.71	5.480%	$0.97	$0.00	$18.68	$286.50
Adiabatic CAES, RESC, 250 MW, 4000 MWh	No	6,500	$2,453	$49	6.804%	$170.27	$12.65	5.480%	$0.69	$0.00	$13.35	$183.62
Adiabatic CAES, RESC, 250 MW, 6000 MWh	No	6,500	$2,748	$49	6.804%	$190.34	$12.81	5.480%	$0.70	$0.00	$13.52	$203.86
Adiabatic CAES, RESC, 250 MW, 12000 MWh	No	6,500	$3,678	$49	6.804%	$253.64	$13.29	5.480%	$0.73	$0.00	$14.02	$267.66
Adiabatic CAES, RESC, 500 MW, 4000 MWh	Yes	6,500	$2,024	$49	6.804%	$141.05	$10.28	5.480%	$0.56	$0.00	$10.85	$151.90
Adiabatic CAES, RESC, 500 MW, 5000 MWh	No	6,500	$2,037	$49	6.804%	$141.95	$10.32	5.480%	$0.57	$0.00	$10.89	$152.84
Adiabatic CAES, RESC, 500 MW, 6000 MWh	Yes	6,500	$2,180	$49	6.804%	$151.68	$10.36	5.480%	$0.57	$0.00	$10.93	$162.61

Table 5.3 – 2023 IRP Update Supply Side Resources (2022 $) (Continued)

Information Presented is Illustrative

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	6,500	$2,327	$49	6.804%	$161.70	$10.44	5.480%	$0.57	$0.00	$11.02	$172.71
Adiabatic CAES, RESC, 500 MW, 12000 MWh	No	6,500	$2,645	$49	6.804%	$183.31	$10.60	5.480%	$0.58	$0.00	$11.19	$194.49
Adiabatic CAES, RESC, 500 MW, 24000 MWh	No	6,500	$3,629	$49	6.804%	$250.29	$11.08	5.480%	$0.61	$0.00	$11.69	$261.98
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
100-hour Iron Air Battery, max CF: 17%	Yes	N/A	$5,367	$160	8.405%	$464.51	$20.77	0.000%	$0.00	$0.00	$20.77	$485.27
Solar - Idaho Falls, ID, 20 MW, 26.1% CF	Yes	4,700	$1,427	$29	7.209%	$104.97	$20.87	1.370%	$0.29	$0.00	$21.16	$126.12
Solar - Lakeview, OR, 20 MW, 27.6% CF	Yes	4,800	$1,527	$32	7.209%	$112.33	$20.87	1.370%	$0.29	$0.00	$21.16	$133.48
Solar - Milford, UT, 20 MW, 30.2% CF	Yes	5,000	$1,412	$29	7.209%	$103.91	$20.87	1.370%	$0.29	$0.00	$21.16	$125.07
Solar - Milford, UT, 200 MW, 30.2% CF	Yes	5,000	$1,140	$29	7.209%	$84.31	$20.87	1.370%	$0.29	$0.00	$21.16	$105.47
Solar - Rock Springs, WY, 200 MW, 27.9% CF	Yes	6,400	$1,187	$30	7.209%	$87.78	$20.87	1.370%	$0.29	$0.00	$21.16	$108.94
Solar - Yakima, WA, 200 MW, 24.2% CF	Yes	1,000	$1,211	$31	7.209%	$89.51	$20.87	1.370%	$0.29	$0.00	$21.16	$110.67
Solar + Storage - Idaho Falls, ID, 200 MW, 26.1% CF + BESS: 100% pwr, 4 hours	No	4,700	$2,879	$54	7.209%	$211.42	$63.19	1.370%	$0.87	$0.00	$64.06	$275.48
Solar + Storage - Lakeview, OR, 200 MW, 27.6% CF + BESS: 100% pwr, 4 hours	No	4,800	$2,864	$56	7.209%	$210.50	$63.19	1.370%	$0.87	$0.00	$64.06	$274.55
Solar + Storage - Milford, UT, 200 MW, 30.2% CF + BESS: 100% pwr, 4 hours	No	5,000	$2,881	$54	7.209%	$211.55	$63.19	1.370%	$0.87	$0.00	$64.06	$275.61
Solar + Storage - Rock Springs, WY, 200 MW, 27.9% CF + BESS: 100% pwr, 4 hours	No	6,400	$2,902	$55	7.209%	$213.18	$63.19	1.370%	$0.87	$0.00	$64.06	$277.23
Solar + Storage - Yakima, WA, 200 MW, 24.2% CF + BESS: 100% pwr, 4 hours	No	1,000	$2,977	$56	7.209%	$218.63	$63.19	1.370%	$0.87	$0.00	$64.06	$282.69
Wind - 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
Wind - 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
Wind - 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
Wind - 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
Wind - 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
Wind - 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
Wind - 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
Wind - 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
Wind - 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
Wind - 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
Wind - 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
Wind -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
Wind + Storage - Pocatello, ID, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	No	4,500	$3,290	$83	6.657%	$224.60	$85.32	4.392%	$3.75	$0.00	$89.07	$313.66
Wind + Storage - Arlington, OR, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	No	1,500	$3,166	$83	6.657%	$216.30	$85.32	4.392%	$3.75	$0.00	$89.07	$305.36
Wind + Storage - Monticello, UT, 200 MW, CF: 29.5% + BESS: 100% pwr, 4 hours	No	4,500	$3,332	$83	6.657%	$227.34	$85.32	4.392%	$3.75	$0.00	$89.07	$316.40
Wind + Storage - Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 100% pwr, 4 hours	No	6,500	$3,252	$83	6.657%	$222.05	$85.32	4.392%	$3.75	$0.00	$89.07	$311.12
Wind + Storage - Goldendale, WA, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	No	1,500	$3,389	$83	6.657%	$231.15	$85.32	4.392%	$3.75	$0.00	$89.07	$320.21
Wind + Storage - Offshore, Northern, CA, CF: 47.0% + BESS: 100% pwr, 4 hours	No	0	$6,545	$182	6.657%	$447.82	$145.32	4.392%	$6.38	$0.00	$151.70	$599.52
Idaho Falls, ID Solar + Wind + BESS: 100% pwr, 4 hours	No	4,700	$6,194	$114	6.657%	$419.87	$148.51	4.392%	$6.52	$0.00	$155.03	$574.90
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
Geothermal - Dual Flash Expansion of Blundell Plant	Yes	4,500	$3,835	$117	6.015%	$237.74	$115.00	0.872%	$1.00	$0.00	$116.00	$353.74
Geothermal - 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
Nuclear - Advanced LWR, 600 MW Site	Yes	N/A	$8,416	$722	5.846%	$534.16	$170.60	9.424%	$16.08	$0.00	$186.68	$720.83
Nuclear - Advanced LWR, 1200 MW Site	Yes	N/A	$7,272	$722	5.846%	$467.32	$152.29	9.424%	$14.35	$0.00	$166.64	$633.97
Advanced Nuclear Reactor (AR), dual unit, with Thermal Storage (1000 Mwe interconnection with 1705 MWh Storage, 638 MW initial base generation)	Yes	N/A	$8,772	$722	5.846%	$554.99	$472.81	9.424%	$44.56	$0.00	$517.36	$1,072.36
Advanced Nuclear Reactor (AR) with improved fuel (1000 Mwe interconnection with 1705 MWh Storage, 690 MW base generation)	Yes	N/A	$8,772	$722	5.846%	$554.99	$286.40	9.424%	$26.99	$0.00	$313.39	$868.39

1/ Input into IRP SO and PAR Model
Results presented without credits
Information Presented is Illustrative
CCUS costs are incremental and include envirnomental upgrade costs but are missing underlying coal unit costs

Table 5.4 – 2023 IRP Update Supply Side Resources (2022 $)

Information Presented is Illustrative

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)		Convert to $/MWh			Levelized Fuel							Credits		$/MWh
Resource Description	Elevation (AFSL)	Capacity Factor 2/	Total Fixed ($/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)	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
SCCT Aero x4	0	33%	$56.02	N/A	$ 4.46	$ 41.26	$ 0.28	14.14%	$ 0.04	$ -	$97.60	$ -	-	$97.60
SCCT Frame "J" x1	0	33%	$34.25	N/A	$ 4.46	$ 40.51	$ 2.32	14.14%	$ 0.33	$ -	$77.41	$ -	-	$77.41
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	0	33%	$114.81	N/A	$ 5.24	$ 48.14	$ 2.44	14.14%	$ 0.34	$ -	$165.73	$ -	-	$165.73
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	0	33%	$182.92	N/A	$ 7.04	$ 66.82	$ 2.23	14.14%	$ 0.32	$ -	$252.28	$ (29.18)	ITC	$223.11
SCCT Frame "J" X1, 100H2 - pipeline Willamette Valley	0	33%	$67.60	N/A	$ 7.04	$ 66.82	$ 2.23	14.14%	$ 0.32	$ -	$136.97	$ (4.12)	ITC	$132.85
SCCT Frame "J" X1, 100H2 - pipeline McNary	0	33%	$118.59	N/A	$ 7.04	$ 66.82	$ 2.23	14.14%	$ 0.32	$ -	$187.95	$ (4.12)	ITC	$183.83
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	0	33%	$166.52	N/A	$ 7.04	$ 66.82	$ 2.27	14.14%	$ 0.32	$ -	$235.94	$ (26.11)	ITC	$209.84
CCCT Dry "J", 1X1	0	78%	$19.89	N/A	$ 4.46	$ 27.80	$ 1.61	14.39%	$ 0.23	$ -	$49.53	$ -	-	$49.53
CCCT Dry "J", DF, 1x1	0	12%	$28.38	N/A	$ 4.46	$ 38.96	$ 1.15	14.39%	$ 0.16	$ -	$68.65	$ -	-	$68.65
SCCT Aero x4	1,500	33%	$58.91	N/A	$ 4.46	$ 41.33	$ 0.30	14.14%	$ 0.04	$ -	$100.58	$ -	-	$100.58
SCCT Frame "J" x1	1,500	33%	$35.51	N/A	$ 4.46	$ 40.48	$ 2.43	14.14%	$ 0.34	$ -	$78.76	$ -	-	$78.76
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	1,500	33%	$119.91	N/A	$ 5.24	$ 48.10	$ 2.55	14.14%	$ 0.36	$ -	$170.93	$ -	-	$170.93
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	1,500	33%	$191.81	N/A	$ 7.04	$ 66.76	$ 2.38	14.14%	$ 0.34	$ -	$261.29	$ (30.57)	ITC	$230.72
SCCT Frame "J" X1, 100H2 - pipeline Southern OR	1,500	33%	$69.03	N/A	$ 7.04	$ 66.76	$ 2.38	14.14%	$ 0.34	$ -	$138.51	$ (4.32)	ITC	$134.19
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	1,500	33%	$174.13	N/A	$ 7.04	$ 66.76	$ 2.38	14.14%	$ 0.34	$ -	$243.61	$ (27.35)	ITC	$216.26
CCCT Dry "J", 1X1	1,500	78%	$20.76	N/A	$ 4.46	$ 27.80	$ 1.68	14.39%	$ 0.24	$ -	$50.49	$ -	-	$50.49
CCCT Dry "J", DF, 1x1	1,500	12%	$28.25	N/A	$ 4.46	$ 38.79	$ 1.15	14.39%	$ 0.16	$ -	$68.35	$ -	-	$68.35
SCCT Aero x4	3,000	33%	$55.59	N/A	$ 4.57	$ 42.48	$ 0.32	14.14%	$ 0.04	$ -	$98.43	$ -	-	$98.43
SCCT Frame "J" x1	3,000	33%	$30.98	N/A	$ 4.57	$ 41.50	$ 2.57	14.14%	$ 0.36	$ -	$75.41	$ -	-	$75.41
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	3,000	33%	$120.14	N/A	$ 5.31	$ 48.84	$ 2.70	14.14%	$ 0.38	$ -	$172.06	$ -	-	$172.06
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	3,000	33%	$195.92	N/A	$ 7.04	$ 66.80	$ 2.52	14.14%	$ 0.36	$ -	$265.59	$ (32.32)	ITC	$233.27
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	3,000	33%	$177.22	N/A	$ 7.04	$ 66.80	$ 2.52	14.14%	$ 0.36	$ -	$246.90	$ (28.92)	ITC	$217.98
CCCT Dry "J", 1X1	3,000	78%	$20.01	N/A	$ 4.57	$ 28.48	$ 1.78	14.39%	$ 0.26	$ -	$50.52	$ -	-	$50.52
CCCT Dry "J", DF, 1x1	3,000	12%	$12.67	N/A	$ 4.57	$ 39.82	$ 1.15	14.39%	$ 0.16	$ -	$53.80	$ -	-	$53.80
SCCT Aero x4	5,050	33%	$59.29	N/A	$ 4.42	$ 41.24	$ 0.34	14.14%	$ 0.05	$ -	$100.92	$ -	-	$100.92
SCCT Frame "J" x1	5,050	33%	$32.85	N/A	$ 4.42	$ 40.15	$ 2.78	14.14%	$ 0.39	$ -	$76.17	$ -	-	$76.17
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	5,050	33%	$129.00	N/A	$ 5.21	$ 47.90	$ 2.91	14.14%	$ 0.41	$ -	$180.22	$ -	-	$180.22
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	5,050	33%	$210.67	N/A	$ 7.04	$ 66.85	$ 2.72	14.14%	$ 0.38	$ -	$280.61	$ (34.85)	ITC	$245.77
SCCT Frame "J" X1, 100H2 - pipeline Utah North	5,050	33%	$72.54	N/A	$ 7.04	$ 66.85	$ 2.72	14.14%	$ 0.38	$ -	$142.49	$ (4.91)	ITC	$137.57
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	5,050	33%	$190.51	N/A	$ 7.04	$ 66.85	$ 2.72	14.14%	$ 0.38	$ -	$260.46	$ (31.18)	ITC	$229.28
SCCT Frame "J" X1, 100H2, BF - pipeline Dave Johnston	5,050	33%	$103.96	N/A	$ 7.04	$ 66.85	$ 2.72	14.14%	$ 0.38	$ -	$173.91	$ (4.91)	ITC	$169.00
SCCT Frame "J" X1, 100H2, BF - pipeline Hunter	5,050	33%	$45.13	N/A	$ 7.04	$ 66.85	$ 2.72	14.14%	$ 0.38	$ -	$115.08	$ (4.91)	ITC	$110.17
CCCT Dry "J", 1X1	5,050	78%	$21.42	N/A	$ 4.42	$ 27.57	$ 1.92	14.39%	$ 0.28	$ -	$51.18	$ -	-	$51.18
CCCT Dry "J", DF, 1x1	5,050	12%	$12.53	N/A	$ 4.42	$ 38.26	$ 1.15	14.39%	$ 0.16	$ -	$52.10	$ -	-	$52.10
SCCT Aero x4	6,500	33%	$68.89	N/A	$ 4.33	$ 39.89	$ 0.38	14.14%	$ 0.05	$ -	$109.22	$ -	-	$109.22
SCCT Frame "J" x1	6,500	33%	$37.89	N/A	$ 4.33	$ 39.32	$ 2.91	14.14%	$ 0.41	$ -	$80.53	$ -	-	$80.53
SCCT Frame "J" x1, 30H2 - onsite hydrogen production and liquified storage	6,500	33%	$138.66	N/A	$ 5.15	$ 47.30	$ 3.05	14.14%	$ 0.43	$ -	$189.44	$ -	-	$189.44
SCCT Frame "J" X1, 100H2 - onsite hydrogen production and liquified storage	6,500	33%	$224.34	N/A	$ 7.04	$ 66.82	$ 2.84	14.14%	$ 0.40	$ -	$294.41	$ (36.50)	ITC	$257.91
SCCT Frame "J" X1, 100H2, BF - onsite hydrogen production and liquified storage	6,500	33%	$203.23	N/A	$ 7.04	$ 66.82	$ 2.84	14.14%	$ 0.40	$ -	$273.30	$ (32.66)	ITC	$240.64
SCCT Frame "J" X1, 100H2, BF - pipeline Naughton	6,500	33%	$74.12	N/A	$ 7.04	$ 66.82	$ 2.84	14.14%	$ 0.40	$ -	$144.18	$ (5.15)	ITC	$139.04
SCCT Frame "J" X1, 100H2, BF - pipeline Jim Bridger	6,500	33%	$93.85	N/A	$ 7.04	$ 66.82	$ 2.84	14.14%	$ 0.40	$ -	$163.91	$ (5.15)	ITC	$158.77
CCCT Dry "J", 1X1	6,500	78%	$23.63	N/A	$ 4.33	$ 27.04	$ 2.01	14.39%	$ 0.29	$ -	$52.97	$ -	-	$52.97
CCCT Dry "J", DF, 1x1	6,500	12%	$21.96	N/A	$ 4.33	$ 37.21	$ 1.15	14.39%	$ 0.16	$ -	$60.48	$ -	-	$60.48

Table 5.4 – 2023 IRP Update Supply Side Resources (2022 $) (Continued)

Information Presented is Illustrative

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)		Convert to $/MWh												$/MWh
					Levelized Fuel							Credits		
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/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)	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
PC CCUS Oxy-Combustion retrofit @ 100 MW pre-retrofit basis	5,000	85%	$53.79	N/A	$ 4.42	$ 81.01	$ 18.68	0.00%	$ -	$ -	$153.49	$ (54.36)	45Q	$99.12
PC CCUS retrofit @ 330 MW pre-retrofit basis	6,500	85%	$38.81	N/A	$ 4.42	$ 69.13	$ 21.70	0.00%	$ -	$ -	$129.64	$ (43.13)	45Q	$86.51
PC CCUS retrofit @ 700 MW pre-retrofit basis	6,500	85%	$26.10	N/A	$ 4.42	$ 64.81	$ 20.79	0.00%	$ -	$ -	$111.69	$ (40.44)	45Q	$71.26
Li-Ion, 4-hour, 200 MW	N/A	17%	$135.55	85%	$ -	$ -	Included	0.00%	$ -	$ -	$135.55	$ (35.64)	ITC	$99.91
Incremental, double energy capacity (L-ion, 4hr, 200MW)	N/A	17%	$116.42	85%	$ -	$ -	Included	0.00%	$ -	$ -	$116.42	$ (29.16)	ITC	$87.26
Li-Ion, 4-hour, 500 MW	N/A	17%	$132.45	85%	$ -	$ -	Included	0.00%	$ -	$ -	$132.45	$ (34.81)	ITC	$97.63
Incremental, double energy capacity (L-ion, 4hr, 500MW)	N/A	17%	$114.21	85%	$ -	$ -	Included	0.00%	$ -	$ -	$114.21	$ (28.63)	ITC	$85.58
Li-Ion, 4-hour, 1000 MW	N/A	17%	$129.06	85%	$ -	$ -	Included	0.00%	$ -	$ -	$129.06	$ (33.91)	ITC	$95.15
Incremental, double energy capacity (L-ion, 4hr, 1000MW)	N/A	17%	$111.32	85%	$ -	$ -	Included	0.00%	$ -	$ -	$111.32	$ (27.90)	ITC	$83.42
Flow Battery, 4 hour, 200 MW	N/A	17%	$188.28	85%	$ -	$ -	$ 0.03	0.00%	$ -	$ -	$188.31	$ (59.22)	ITC	$129.08
Incremental, double energy capacity (Flow, 4hr, 200MW)	N/A	17%	$125.98	85%	$ -	$ -	$ -	0.00%	$ -	$ -	$125.98	$ (49.62)	ITC	$76.36
Flow Battery, 4 hour, 1000 MW	N/A	17%	$171.49	70%	$ -	$ -	$ 0.13	0.00%	$ -	$ -	$171.62	$ (54.97)	ITC	$116.65
Incremental, double energy capacity (Flow, 4hr, 1000MW)	N/A	17%	$112.48	85%	$ -	$ -	$ -	0.00%	$ -	$ -	$112.48	$ (45.57)	ITC	$66.91
Gravity Battery, 4 hour,	N/A	17%	$256.58	83%	$ -	$ -	Included	0.00%	$ -	$ -	$256.58	$ (111.55)	ITC	$145.03
Incremental, double energy capacity (Gravity, 4hr, 200MW)	N/A	17%	$109.65	83%	$ -	$ -	Included	0.00%	$ -	$ -	$109.65	$ (60.81)	ITC	$48.84
Gravity Battery, 4 hour,	N/A	17%	$239.97	83%	$ -	$ -	Included	0.00%	$ -	$ -	$239.97	$ (104.32)	ITC	$135.66
Incremental, double energy capacity (Gravity, 4hr, 500MW)	N/A	17%	$98.17	83%	$ -	$ -	Included	0.00%	$ -	$ -	$98.17	$ (54.44)	ITC	$43.72
Gravity Battery, 4 hour,	N/A	17%	$149.66	83%	$ -	$ -	Included	0.00%	$ -	$ -	$149.66	$ (65.06)	ITC	$84.60
Incremental, double energy capacity (Gravity, 4hr, 1000MW)	N/A	17%	$57.20	83%	$ -	$ -	Included	0.00%	$ -	$ -	$57.20	$ (31.72)	ITC	$25.48
Adiabatic CAES, RESC, 125 MW, 1000 MWh	6,500	33%	$61.36	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$62.48	$ (18.35)	ITC	$44.12
Adiabatic CAES, RESC, 125 MW, 1250 MWh	6,500	38%	$55.00	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$56.12	$ (16.46)	ITC	$39.65
Adiabatic CAES, RESC, 125 MW, 1500 MWh	6,500	38%	$60.08	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$61.20	$ (18.18)	ITC	$43.01
Adiabatic CAES, RESC, 125 MW, 2000 MWh	6,500	38%	$61.87	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$62.99	$ (18.78)	ITC	$44.21
Adiabatic CAES, RESC, 125 MW, 3000 MWh	6,500	38%	$65.97	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$67.09	$ (20.16)	ITC	$46.93
Adiabatic CAES, RESC, 125 MW, 6000 MWh	6,500	38%	$87.21	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$88.33	$ (27.31)	ITC	$61.02
Adiabatic CAES, RESC, 250 MW, 4000 MWh	6,500	38%	$55.90	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$57.01	$ (17.24)	ITC	$39.78
Adiabatic CAES, RESC, 250 MW, 6000 MWh	6,500	38%	$62.06	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$63.17	$ (19.31)	ITC	$43.86
Adiabatic CAES, RESC, 250 MW, 12000 MWh	6,500	38%	$81.48	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$82.59	$ (25.84)	ITC	$56.75
Adiabatic CAES, RESC, 500 MW, 4000 MWh	6,500	33%	$52.02	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$53.14	$ (16.00)	ITC	$37.14
Adiabatic CAES, RESC, 500 MW, 5000 MWh	6,500	38%	$46.53	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$47.64	$ (14.31)	ITC	$33.33
Adiabatic CAES, RESC, 500 MW, 6000 MWh	6,500	38%	$49.50	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$50.62	$ (15.32)	ITC	$35.30
Adiabatic CAES, RESC, 500 MW, 8000 MWh	6,500	38%	$52.58	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$53.69	$ (16.35)	ITC	$37.34

Table 5.4 – 2023 IRP Update Supply Side Resources (2022 $) (Continued)

Information Presented is Illustrative

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)					Levelized Fuel							Credits		$/MWh
Resource Description	Elevation (AFSL)	Capacity Factor 3/	al Fixed($/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)	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	6,500	38%	$59.21	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$60.32	$ (18.58)	ITC	$41.74
Adiabatic CAES, RESC, 500 MW, 24000 MWh	6,500	38%	$79.75	60%	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$80.87	$ (25.50)	ITC	$55.37
Pumped Hydro, Southern OR	N/A	42%	$78.09	78%	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ (21.69)	ITC	$56.91
Pumped Hydro, Portland North Coast	N/A	42%	$78.09	78%	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ (21.69)	ITC	$56.91
Pumped Hydro, Central WY	N/A	42%	$78.09	78%	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ (21.69)	ITC	$56.91
Pumped Hydro, Eastern WY	N/A	42%	$78.09	78%	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ (21.69)	ITC	$56.91
Pumped Hydro, Central UT	N/A	42%	$78.09	78%	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ (21.69)	ITC	$56.91
100-hour Iron Air Battery, max CF: 17%	N/A	17%	$323.95	40%	$ -	$ -	Included	0.00%	$ -	$ -	$323.95	$ (102.03)	ITC	$221.92
Solar - Idaho Falls, ID, 20 MW, 26.1% CF	4,700	26%	$55.16	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$55.90	$ (19.00)	PTC	$36.90
Solar - Lakeview, OR, 20 MW, 27.6% CF	4,800	28%	$55.21	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$55.95	$ (19.00)	PTC	$36.95
Solar - Milford, UT, 20 MW, 30.2% CF	5,000	30%	$47.28	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$48.01	$ (19.00)	PTC	$29.01
Solar - Milford, UT, 200 MW, 30.2% CF	5,000	30%	$39.87	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$40.60	$ (19.00)	PTC	$21.60
Solar - Rock Springs, WY, 200 MW, 27.9% CF	6,400	28%	$44.57	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$45.31	$ (19.00)	PTC	$26.31
Solar - Yakima, WA, 200 MW, 24.2% CF	1,000	24%	$52.20	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$52.94	$ (19.00)	PTC	$33.94
Solar + Storage - Idaho Falls, ID, 200 MW, 26.1% CF + BESS: 100% pwr, 4 hours	4,700	26%	$120.49	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$121.22	$ (54.64)	ITC	$66.58
Solar + Storage - Lakeview, OR, 200 MW, 27.6% CF + BESS: 100% pwr, 4 hours	4,800	28%	$113.56	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$114.29	$ (54.64)	ITC	$59.65
Solar + Storage - Milford, UT, 200 MW, 30.2% CF + BESS: 100% pwr, 4 hours	5,000	30%	$104.18	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$104.92	$ (54.64)	ITC	$50.28
Solar + Storage - Rock Springs, WY, 200 MW, 27.9% CF + BESS: 100% pwr, 4 hours	6,400	28%	$113.43	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$114.17	$ (54.64)	ITC	$59.53
Solar + Storage - Yakima, WA, 200 MW, 24.2% CF + BESS: 100% pwr, 4 hours	1,000	24%	$133.35	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$134.08	$ (54.64)	ITC	$79.44
Wind - Pocatello, ID, 20 MW, CF: 37.1%	4,500	37%	$59.30	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$60.27	$ (19.00)	PTC	$41.27
Wind - Pocatello, ID, 200 MW, CF: 37.1%	4,500	37%	$47.74	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$48.71	$ (19.00)	PTC	$29.71
Wind - Arlington, OR, 20 MW, CF: 37.1%	1,500	37%	$59.05	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$60.03	$ (19.00)	PTC	$41.03
Wind - Arlington, OR, 200 MW, CF: 37.1%	1,500	37%	$47.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$48.10	$ (19.00)	PTC	$29.10
Wind - Monticello, UT, 20 MW, CF: 29.5%	4,500	30%	$75.22	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$76.19	$ (19.00)	PTC	$57.19
Wind - Monticello, UT, 200 MW, CF: 29.5%	4,500	30%	$60.79	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$61.76	$ (19.00)	PTC	$42.76
Wind - Medicine Bow, WY, 20 MW, CF: 43.6%	6,500	44%	$49.90	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$50.88	$ (19.00)	PTC	$31.88
Wind - Medicine Bow, WY, 200 MW, CF: 43.6%	6,500	44%	$40.11	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$41.08	$ (19.00)	PTC	$22.08
Wind - Goldendale, WA, 20 MW, CF: 37.1%	1,500	37%	$61.60	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$62.58	$ (19.00)	PTC	$43.58
Wind - Goldendale, WA, 200 MW, CF: 37.1%	1,500	37%	$49.04	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$50.01	$ (19.00)	PTC	$31.01
Wind - Offshore, Northern, CA, CF: 47.0%	0	47%	$103.63	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$104.60	$ (13.36)	ITC	$91.24
Wind -Offshore, Northern, CA, 1GW, CF: 47.0%	0	47%	$103.59	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$104.56	$ (13.36)	ITC	$91.20
Wind + Storage - Pocatello, ID, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	4,500	37%	$96.51	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$97.48	$ (54.64)	ITC	$42.84
Wind + Storage - Arlington, OR, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	37%	$93.96	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$94.93	$ (54.64)	ITC	$40.29
Wind + Storage - Monticello, UT, 200 MW, CF: 29.5% + BESS: 100% pwr, 4 hours	4,500	30%	$122.44	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$123.41	$ (54.64)	ITC	$68.77
Wind + Storage - Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 100% pwr, 4 hours	6,500	44%	$81.46	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$82.43	$ (54.64)	ITC	$27.79
Wind + Storage - Goldendale, WA, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	37%	$98.53	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$99.50	$ (54.64)	ITC	$44.86
Wind + Storage - Offshore, Northern, CA, CF: 47.0% + BESS: 100% pwr, 4 hours	0	47%	$145.61	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$146.59	$ (54.64)	ITC	$91.94
Idaho Falls, ID Solar + Wind + BESS: 100% pwr, 4 hours	4,700	62%	$106.00	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.85	$106.86	$ (54.64)	ITC	$52.22
Lakeview, OR Solar + Wind + BESS: 100% pwr, 4 hours	4,800	62%	$103.73	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.85	$104.59	$ (54.64)	ITC	$49.95
Milford, UT Solar + Wind + BESS: 100% pwr, 4 hours	5,000	58%	$113.73	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.85	$114.58	$ (54.64)	ITC	$59.94
Rock Springs, WY Solar + Wind + BESS: 100% pwr, 4 hours	6,400	70%	$88.77	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.85	$89.62	$ (54.64)	ITC	$34.98
Yakima, WA Solar + Wind + BESS: 100% pwr, 4 hours	1,000	59%	$107.35	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.85	$108.20	$ (54.64)	ITC	$53.56
Geothermal - Dual Flash Expansion of Blundell Plant	4,500	90%	$44.87	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$44.87	$ (19.00)	PTC	$25.87
Geothermal - Greenfield Binary Plant	4,500	90%	$58.08	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$58.08	$ (19.00)	PTC	$39.08
Nuclear - Advanced LWR, 600 MW Site	N/A	86%	$95.68	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$95.68	$ (19.00)	PTC	$76.68
Nuclear - Advanced LWR, 1200 MW Site	N/A	86%	$84.15	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$84.15	$ (19.00)	PTC	$65.15
Advanced Nuclear Reactor (AR), dual unit, with Thermal Storage (1000 Mwe interconnection with 1705 MWh Storage, 638 MW initial base generation)	N/A	86%	$142.34	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$142.34	$ (19.00)	PTC	$123.34
Advanced Nuclear Reactor (AR) with improved fuel (1000 Mwe interconnection with 1705 MWh Storage, 690 MW base generation)	N/A	86%	$115.27	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$115.27	$ (19.00)	PTC	$96.27

1/ Input into IRP SO and PAR Model
2/ Wind and solar shapes are input into IRP Plexos Model
NC = Not Calculated
Tax credits are before Energy Community bonus as it is site specific
Information Presented is Illustrative
CCUS costs are incremental and include envirnomental upgrade costs but are missing underlying coal unit costs

Modeling Enhancements and Resource Updates

Suspension of the 2022 All-Source RFP

The decision to suspend the 2022 All-Source RFP was made on September 29, 2023, four months after the filing of the 2023 IRP. The decision to suspend was taken for multiple reasons, all with the intent to ensure that our procurement decisions are based on the most up-to-date information and in the best interests of our ratepayers, while also considering the evolving market conditions and other pertinent factors: (1) The stay of EPA's disapproval of Utah's state ozone plan; (2) Ongoing rulemaking by the EPA regarding greenhouse gas emissions, with impacts on our system to be determined; (3) Wildfire risk and associated liability across our six-state service area and throughout the West; and (4) Evolving extreme weather risks that necessitate further decision-making regarding PacifiCorp's operational and resource requirements.

In parallel with the modeling updates, the PacifiCorp has engaged in a bilateral effort to procure commercially viable battery technology by June 1, 2026, to ensure that such near-term opportunities remain available. The 2023 IRP Update provides new direction on resource needs spanning the timeframe of the 2022 All-Source RFP and indicates appropriate next steps.6

Transmission Option Updates

The 2023 IRP Update has changed the way the majority of transmission projects are modeled. Transmission projects do not have to be selected as one unit or zero units, but can be selected in any size from zero to 100% of a line. In practice, this means that if the model deems it most economic to build .25 units of a local area upgrade can be built in 2033, another .3 units can be built in 2034 and the balance can be left unbuilt. For local area upgrades, this correlates more closely to real world cluster project transmission and funding where (as an example) 30% of the cluster chooses to move forward and the balance withdraws. When considering incremental lines, given the far future timelines for those items, this modeling provides appropriate flexibility considering permitting nuances and the complex nature of transmission approvals. Selection of a portion of an incremental transmission line in the distant future signals that this transmission option has value to the system and warrants further study to determine the best sizing and timing of the line. The exception to this change is that known, incremental, near-term projects such as the Boardman to Hemingway and Energy Gateway South lines must be selected as whole projects. Further engagement with stakeholders regarding transmission modeling methodology will occur in the 2025 IRP public input meetings series.

[6] Please refer to Chapter 6 – Portfolio Development, and Chapter 7 – Action Plan.

Other Contracts

PacifiCorp continually updates and negotiates with contracted facilities. The most current contracted resources, as of January 1, 2024, are being used for the 2023 IRP Update. Given timing, this is the last update to contracted resources that will be made for the update. Between the 2023 IRP and the 2023 IRP Draft Update, PacifiCorp has signed an additional 13 megawatts of small Oregon Community Solar Projects that will be reflected in the 2023 IRP Update.

As an original purchaser of the output of the Priest Rapids and Wanapum hydro projects, PacifiCorp has an annual option to purchase approximately 100 megawatts of the output from these plants at market-based rates. For this 2023 IRP Update, it has been assumed that PacifiCorp elects to purchase this hydro output in each year of the study horizon.

CHAPTER 6 – PORTFOLIO DEVELOPMENT

Introduction

PacifiCorp used PLEXOS' three optimization models to develop an updated preferred portfolio based on inputs and assumptions that have changed since the 2023 Integrated Resource Plan (IRP). This updated resource portfolio is consistent with PacifiCorp's most recent load-and-resource balance.[1] This chapter presents the 2023 IRP Update preferred portfolio, a comparison of changes relative to the 2023 IRP preferred portfolio, and an updated assessment of certain portfolio variants.

Updates

Key Updates

As discussed in Chapter 5, key changes in this 2023 IRP Update are driven by the U.S. Environmental Protection Agency's (EPA) approval of Wyoming's state Ozone Transport Rule (OTR) plan, the stay of EPA's disapproval of Utah's state OTR plan, extensions to the assumed operational life of new natural gas generating resources, energy storage acquisition strategy, forecast load demand, higher coal prices, and natural gas and wholesale power market price updates.

The first of these items, the OTR, is particularly impactful. Since the time the 2023 IRP was filed, the Tenth Circuit Court of Appeals granted PacifiCorp's and other petitioners' motion to stay the EPA's final disapproval of Utah's state implementation plans regarding cross-state ozone transport obligations under the 2015 ozone National Ambient Air Quality Standards (referred to herein as the Ozone Transport Rule or OTR). The stay will remain in place while the case is litigated, or until further order of the court. The court held that the agency may not enforce the federal plan while the stay remains in place. PacifiCorp is thus not subject to the federal ozone transport requirements in Utah, which would have become effective on August 4, 2023. Requirements for the 2024 ozone season and beyond will depend on the outcome of litigation. In granting the stay, the court indicated that PacifiCorp and the other petitioners are likely to succeed on the merits. As discussed later in this chapter, PacifiCorp has produced a variant analysis to understand the potential impacts of litigation outcomes that could reinstate OTR compliance requirements for Utah resources.

Additionally, the EPA finalized approval of Wyoming's interstate ozone transport plan on December 19, 2023. The final approval of Wyoming's plan removes federal cross-state ozone transport requirements from electric generating units in the state, including PacifiCorp's generating units. The rule is discussed in Chapter 3.

[1] See Chapter 4 – Load and Resource Balance

Other Updates

In addition to the key updates noted above, the 2023 IRP Update includes conventional or traditional planning updates where data has changed following PacifiCorp's filed 2023 IRP. Included are updates to load forecast, market prices, changes in existing resources, and PacifiCorp's contracts with other entities.

Certain updates to proxy resource data are responsive stakeholder feedback. These updates result in better alignment with potential for some renewable categories, such as pumped storage and geothermal resources, as well as updates to thermal and nuclear assumptions.

Gas resources have been updated to reflect the potential flexibility of fuel types as discussed in Chapter 5. This ability to transition to alternative fuels allows gas resources to operate and provide benefits over a longer useful life. This allows upfront costs to be amortized over a longer useful life, which reduces annual costs and leads to greater probability that these resources will be selected.

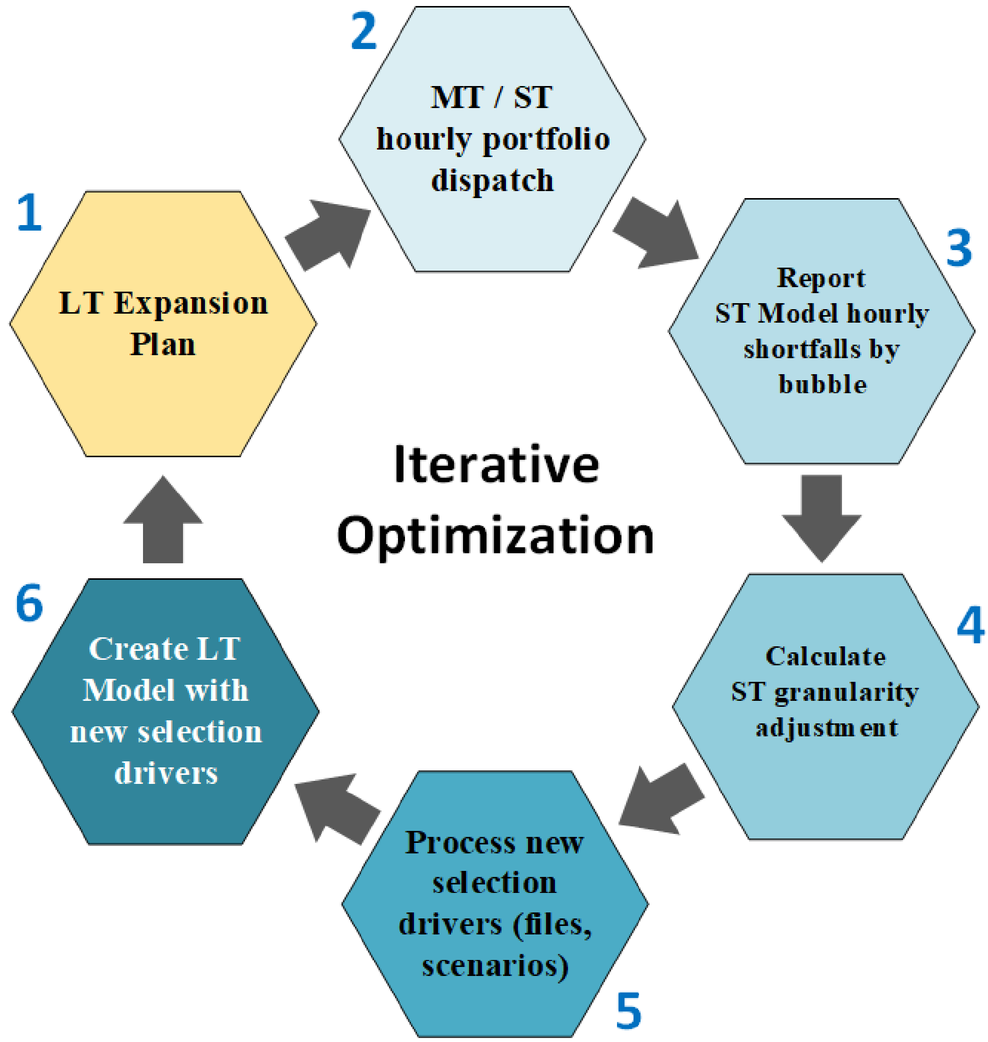
The change to transmission modeling discussed in Chapter 5 has an impact on portfolio selections as PLEXOS is able to "right-size" transmission to fit needs more precisely. This also means that transmission selections can be built in multiple years, reflecting the reality that resources studied in the PacifiCorp Transmission cluster study process may not all reach operational status in the same year, and transmission investments to enable these projects could potentially be staggered.

Within the limits of their useful lives, coal plants are eligible to be retired any time after January 1, 2024, and gas plants are eligible for retirement at any point after January 1, 2026. This serves to standardize assumptions and allows the model to indicate if earlier retirements would be selected if feasible. To the extent that earlier retirements are indicated within the limits of PLEXOS, further study could be made.

Portfolio Development Process Overview

In the 2023 IRP Update process, the company revised the process for developing candidate portfolios. In response to stakeholder feedback requesting greater transparency in the process of making portfolio-level reliability adjustments and model simulation granularity adjustments, the company implemented a new, iterative process to generate candidate portfolios. Each iteration in the portfolio process represents one "phase", and each phase consists of six steps. Figure 6.1 illustrates the six cyclical steps in this new process, followed by an overview and detailed description of these steps. Completion of all six steps of this process constitutes a single phase of a study.

Figure 6.1 – The Six Steps of One Portfolio Development Phase



Overview of Steps

Step 1

For each case, the long-term (LT) capacity expansion model is run according to the parameters and constraints of the particular study. This results in an expansion plan of selected resources, retirement decisions and transmission option selection. Collectively these selections are called a "portfolio".

Step 2

The LT model expansion plan is fed into the medium-term (MT) and short-term (ST) models. These two models are run in sync where the MT model optimizes the timing and allocation of constraints, and the ST model performs an hourly dispatch of the portfolio using the MT model's determinations. For example, if there is limited fuel available to a thermal unit during a year, the MT will allocate that fuel across the year to give the ST model direction for how much fuel is available in each part of the year.

Step 3

The ST model reports shortfalls that must be covered for each location (or "bubble") in the IRP transmission topology.

Step 4

The granularity adjustment is calculated as the difference in resource value between the ST model results and the LT model results. This calculation gives the mathematical magnitude of the ST model's superior granularity.

Step 5

The reliability shortfalls and granularity adjustments are formatted into data files that can be used in the next phase of the LT model to improve its outcomes.

Step 6

The next phase LT model is built in PLEXOS, where shortfalls are represented as an additional load requirement and the granularity adjustment is represented as a cost adder to every resource option.

Granularity Adjustment Detail

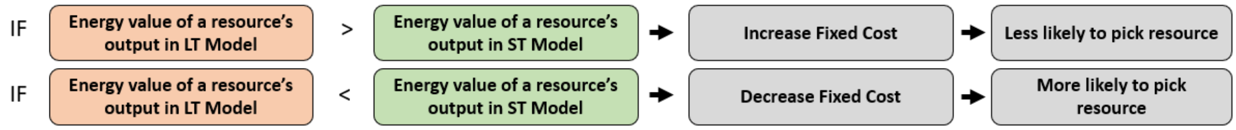
The capacity expansion/LT and ST models in PLEXOS each run and solve using a different view of the study horizon. The LT model uses 7 blocks per month over the 20-year horizon. This means the LT model groups similar hours into a block, and then concurrently solves the entire 20-year horizon. In contrast, the ST model concurrently solves (or dispatches) each week of each year, or roughly 52 steps of 168 hours each, for a specified portfolio of resources as selected in the LT model. In the 7-block LT view, a resource is seen as having a certain amount of value to the system in the 84 blocks it evaluates during each year (7 blocks per month times 12 months). When the ST model dispatches those same resources at an hourly granularity, the ST model also reports the value it calculates for each resource on an annual basis. The mathematical difference between the ST value and the LT value is the granularity adjustment.

This adjustment, determined independently in step 4 of each phase of portfolio development, is used in the subsequent phase of the process so as to bring the ST model's finer granularity analysis into the LT model, improving the consistency of capacity expansion.

By contrast, in the 2023 IRP, the ST model resource value results were used to inform additional resource selections that were then applied directly in a final run of the ST model. This new iteratively phased approach means that resource selections occur in the LT model using its capacity expansion logic, but with the benefit of the ST model's resource value determinations. Also responsive to stakeholder feedback, a new granularity adjustment is now calculated for every portfolio developed, rather than using one granularity adjustment calculated for each price-policy scenario. This change, while performance and resource intensive, is responsive to stakeholder concerns regarding the limitations of the prior methodology.

Figure 6.2 illustrates the calculation of the granularity adjustment, which is completely derived from ST and LT model outputs. A distinct granularity adjustment is calculated for every individual resource in each year of every phase of every study.

Figure 6.2 – Granularity Adjustment Determination



This iterative process was carried out for all price-policy scenarios and variant studies. Since each unique granularity adjustment was then fed back into the LT model for the next run, in practice, this means that no two LT model runs have the same granularity adjustment, and each adjustment is wholly dependent upon the performance of resources within that specific portfolio.

Reliability Adjustment Detail

Stakeholders in the 2023 IRP also identified concerns related to the methodology for making reliability adjustments. For the 2023 IRP Update, in step 3 of each phase, hourly reliability shortfalls are identified by the ST model to be fed back into the LT model to enhance resource selections. As previously noted, the LT model evaluates average conditions during blocks of hours. While this allows the LT model to solve a long horizon in a reasonable time, the average conditions in a block of hours can result in shortfalls in some hours within a block when viewed with enhanced granularity. The ST model is able to identify these hours in its evaluation, and these deficiencies are reported by the ST model as hourly shortfalls.

While granularity adjustments are included as an increase or decrease in fixed costs, reliability adjustments are now included as an increase in the load forecast. As with the granularity adjustments these additions are specific to each study's portfolio. However, unlike the granularity adjustment, the shortfall additions to the load file are cumulatively added to the LT need. ST studies are always run with the base load forecast to verify whether LT additions were sufficient to eliminate shortfalls in all hours.

As an example, suppose the phase one portfolio (the very first iteration of the six steps for a particular study) reports a shortfall of 250 megawatts in Utah North on June 8, 2032, at 8 PM. This 250 megawatt shortfall is added to the base load file on June 8, 2032, in Utah North, and phase 2 is run with the adjusted load file. If the portfolio selected in phase two reports an additional shortfall of 50 megawatt in Utah North on June 8, 2032, at 8 PM, the 50 megawatt shortfall is added to the adjusted load file, such that the load for that day and time is now 300 megawatts higher than the original phase one load forecast. Once no shortfalls are reported by the ST model (using the base load forecast), the adjusted load file used to select a reliable portfolio continues to be applied so that each later phase includes requirements sufficient to induce the LT model to select a portfolio that is reliable. These adjustments are unique to each price policy scenario/variant.

These changes in the application of reliability and granularity adjustments has led to an iterative process where there is a loop from the LT model to the MT and ST models and back to the LT model. This process can be continual, and results evolve over multiple phases. At some point, the process leads to a portfolio that is reliable. Additionally, ongoing granularity adjustments will lead to diminishing returns on cost reductions. The process is considered complete once portfolios are reliable and the present value revenue requirement (PVRR) of reliable portfolios reports changes within a small range.

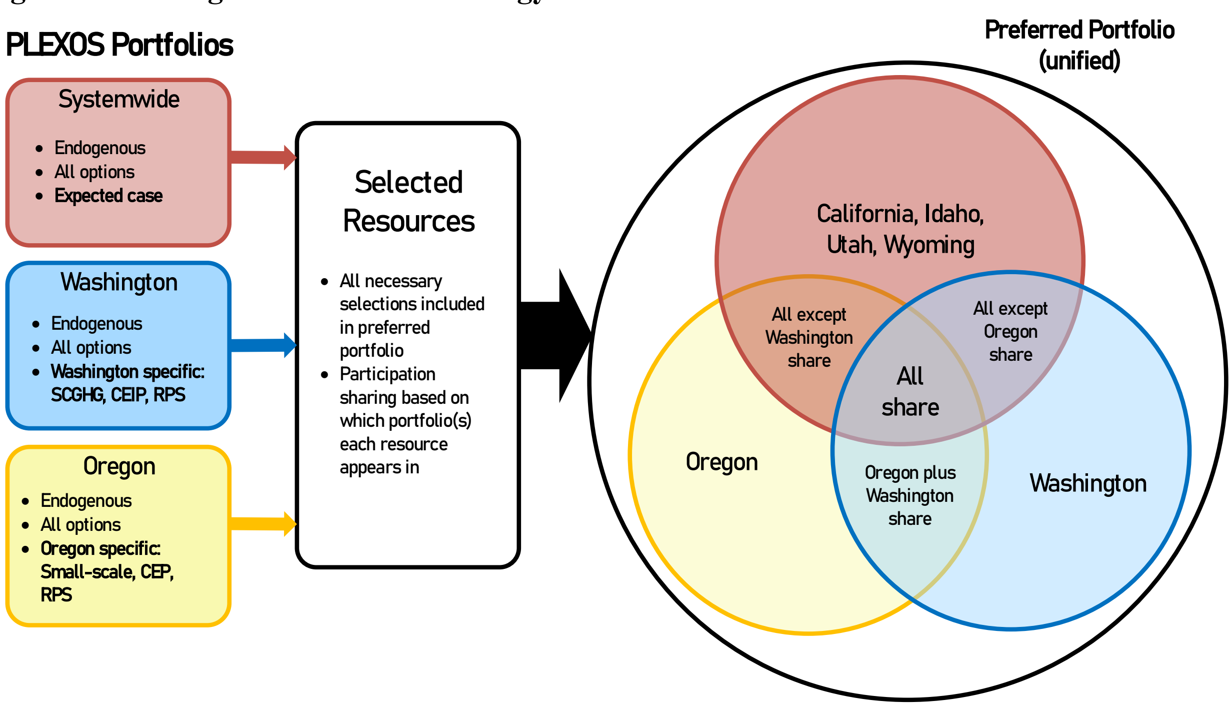
Preferred Portfolio Development

As discussed above, the iterative study process was completed for all studies in the 2023 IRP Update. The fully unconstrained Medium Gas, Medium CO_2 (MM) study was iterated through eight distinct phases of granularity or reliability adjustments before reaching a point where the results stabilized, and no further significant progress was evident. The portfolios generated in this eight-phase study process were all eligible to be selected as the systemwide best portfolio.

Given state policy requirements, however, the systemwide portfolio was not expected to meet all state-specific compliance obligations. To generate an optimal, all-state portfolio, the systemwide portfolio must be integrated with selections optimized under each state's requirements, requiring additional studies. These additional studies were created by layering state compliance constraints into the LT model, and these model runs went through the same iterative process as described above. The preferred portfolio leveraged the resource selections of the least-cost MM system-wide portfolio, the least-cost MM Oregon Policy portfolio and the least-cost Social Cost of Greenhouse Gas (SC-GHG) Washington Policy portfolio.

Figure 6.3 illustrates the strategy for the integration of optimal resource selections for all states. Using the figure as a guide, if a given resource is selected as optimal for one state but is not selected in the systemwide portfolio nor for any other individual state, then that resource is assumed to belong to the selecting state to meet its specific requirements. If a resource is selected as optimal for a specific state and systemwide portfolio, it is assumed shared.

Figure 6.3 – Integrated Portfolio Strategy



Systemwide Portfolio

This portfolio was developed through the iterative process without any initial restrictions on resource selection, state needs, transmission availability, or any other inputs. Given the universal benefit of some number of renewables in the iterative approach (phases with higher renewable selections led to an overall lower PVRR), it became clear that the LT model would select additional renewables if the model had the benefit of improved granularity. PacifiCorp began testing strategies that required the model to pick minimum amounts of renewable resources that interconnection study results indicate could be available through 2028. The model was still allowed to select additional renewable resources. The amounts tested ranged from 15% to 100% of the resources modeled as available through 2028 from the serial, transition, cluster one and cluster two interconnection studies. The version requiring 25% of these resources had the lowest PVRR of the tests, therefore the 25% requirement was carried through further systemwide cases. The MM systemwide case requiring the selection of 25% of the cluster study options serves as the starting point for the integrated preferred portfolio. This approach allowed multiple additional iterations to be avoided without risk of overbuilding renewables.

Oregon and Washington Policy Portfolios

While many resources identified in the unconstrained systemwide portfolio are cost-effective for Washington and Oregon policy requirements, separate portfolios were developed which included the policy requirements specific to each state. These portfolios were developed in tandem with the system-level portfolio using the same iterative process. State policy studies include the entire system but also compliance metrics based on that state's regulations. The LT model thus produces a portfolio in these studies in which the entire system is optimized in a way that complies with the state policies. Per Figure 6.1, above, a state's assumed share of resources is determined according to the overlap observed in the integration process, described in detail for Oregon and Washington respectively, below.

The least-cost versions of the Oregon and Washington policy portfolios are used in two ways. First, an allocated portion of the selections identified in the compliance portfolios are integrated with the systemwide portfolio. While the systemwide portfolio is the starting point given the substantial overlap among the portfolios, the modifications associated with the state policy portfolios may increase, accelerate, or replace selections in the systemwide portfolio to produce an integrated preferred portfolio that addresses all requirements. Second, the integrated preferred portfolio resource selections are assumed allocated to California, Idaho, Utah, and Wyoming only to the extent they were identified in the systemwide portfolio. Similarly, resource selections are assumed allocated to Oregon only to the extent identified in the Oregon policy portfolio, and resource selections are allocated to Washington only to the extent identified in the Washington policy portfolio.

This approach differs from the approach used in the March 2023 filing of the Oregon Clean Energy Plan (CEP), the March 2023 Washington Clean Energy Implementation Plan (CEIP) re-filing, and the November 2023 Washington Biennial Update portfolio developments. Specifically, the previous approach used in the aforementioned filings locked-in the unconstrained systemwide portfolio and then added only the minimal incremental resource selections needed to meet state policies. This earlier approach in PacifiCorp's first CEP and CEIP reports was viewed by PacifiCorp as entirely valid in an environment where all portfolios were very closely aligned and optimal resource additions were minimal. Responsive to stakeholder and commission feedback, the new approach for the 2023 IRP Update integrates resource selections from fully optimized state policy model runs rather than "layering resources on top" of the systemwide solution.

This approach is expected to be discussed with regulators and stakeholders and subsequently refined for the 2025 IRP. In the current version of this approach, resource adequacy is achieved for the system but is not examined for each individual jurisdiction. For the 2025 IRP, the use of individual jurisdictional forecasts and individual resource allocations is being contemplated to ensure that each state is independently resource adequate. This prevents resource adequacy impacts of individual state policies from shifting to other states.

Oregon Integration

The Oregon policy study represents the model's view of the least-cost, least-risk resource portfolio for Oregon, irrespective of the unconstrained systemwide portfolio. The process of integration maintains each other states' optimal resource outcomes without diminishing Oregon's selections. However, Oregon is not beholden to adopt the model's recommendations, and the PacifiCorp intends to continue its dialogue with all states to seek the best solutions for its customers. A comprehensive compliance strategy for Oregon will be influenced by staff and Commission guidance, stakeholder engagement, MSP negotiations, resource acquisition procedures, and a number of possible compliance options beyond capacity expansion. These additional considerations are outside the scope of the 2023 IRP Update, but will be considered in separate engagements and reports according to Oregon requirements.

Relative to the systemwide portfolio, the Oregon policy study adds peaking resources with renewable fuel in 2030, additional utility scale wind, as well as small-scale renewable resources mandated by Oregon law. The renewable-fueled peaking unit replaces a hydrogen convertible gas-fueled peaking unit from the systemwide portfolio. This resource is assumed to be fully allocated to Oregon. The Oregon share of the incremental utility-scale wind resource additions is comparable to the small-scale wind requirement, and so Oregon's share of utility scale wind will be acquired as small-scale resources in the integrated portfolio. Utility-scale solar selections decrease in the Oregon run compared to the unconstrained systemwide portfolio, even when required small-scale solar additions are considered. Therefore, utility-scale solar in the preferred portfolio is reduced slightly relative to the systemwide portfolio to represent a reduction in Oregon's share of that resource. The Oregon policy study also results in an acceleration of battery resources relative to the systemwide portfolio. Oregon energy efficiency and demand response measures, already fully allocated to Oregon, are taken directly from the results of the Oregon compliance study for inclusion in the integrated all-state preferred portfolio.

Washington Integration

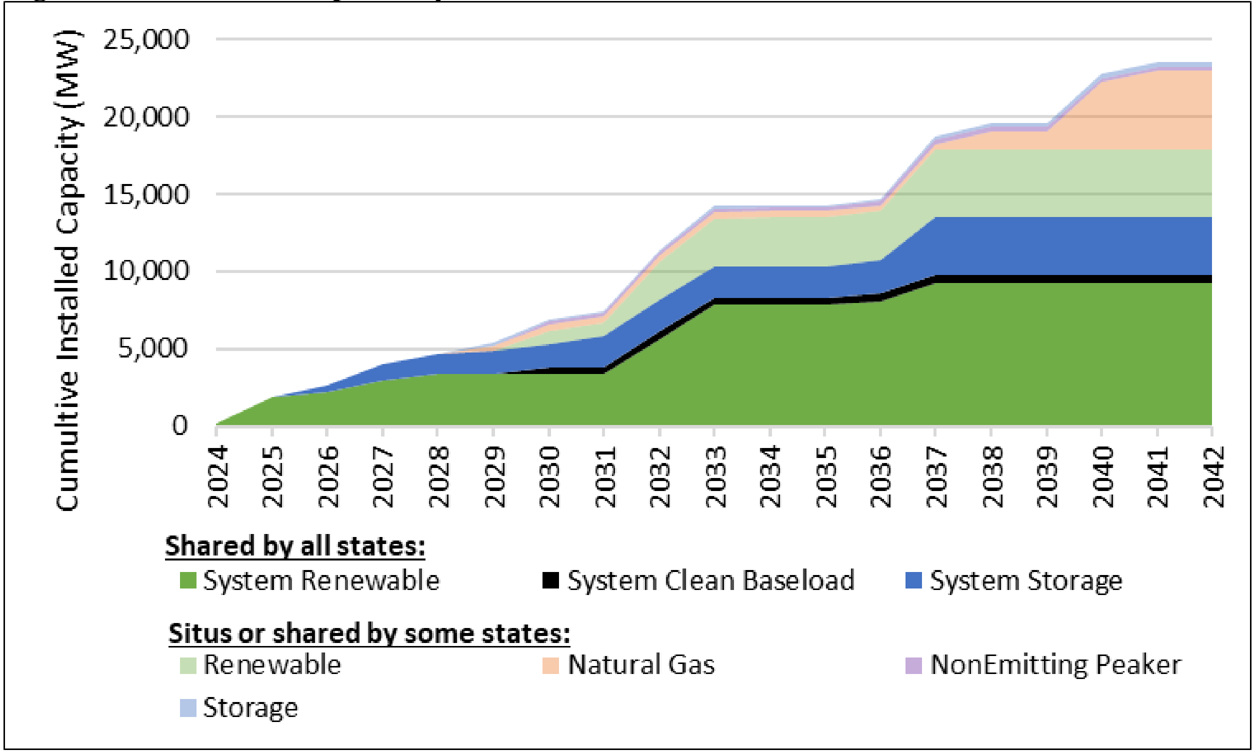
Similar to Oregon's policy portfolio integration, Washington's policy study was compared to the unconstrained systemwide portfolio, and Washington's situs selections were integrated based on the differences between resource selections in the two portfolios. As anticipated, when the system is planned and operated on the basis of the SC-GHG CO_2 assumption, as in the Washington policy study, total system resource selections are considerably in excess of those needed by Washington to achieve Clean Energy Transformation Act (CETA) clean energy targets. This is because while resources are selected for the entire system, Washington only needs a relatively small share of those resources for its own jurisdictional goals. A second study was therefore performed which assumed a larger share of new resources attributed to Washington, based on Washington's roughly 22% share of PacifiCorp's western states (also known as Control Area Generation West or CAGW). This results in fewer total resources and ensures that selected resources are the best of what is available. After accounting for the policy benefits of Washington's system share of the resource selections previously identified in the systemwide study, the CAGW study results indicated that wind resources were the best means of compliance, and over 400 megawatts of additional wind resources in 2030 were incorporated in the preferred portfolio that would be fully allocated to Washington. Washington is also allocated additional wind and solar resources in 2032-2037, and a small amount of battery resources which were accelerated into 2029. Additionally, demand response and energy efficiency in the preferred portfolio match the selections from the Washington policy run.

A comprehensive compliance strategy for Washington will be influenced by staff and Commission guidance, stakeholder engagement, MSP negotiations, resource acquisition procedures, and a number of possible compliance options beyond capacity expansion. These additional considerations are outside the scope of the 2023 IRP Update, but will be considered in separate engagements and reports according to Washington requirements.

Preferred Portfolio Integration Outcomes

The integrated preferred portfolio resulting from the changes described above is mostly shared among all states, though differences grow in the second half of the study horizon, as shown in Figure 6.4.

Figure 6.4 – 2023 IRP Update System and Situs Resource Allocations



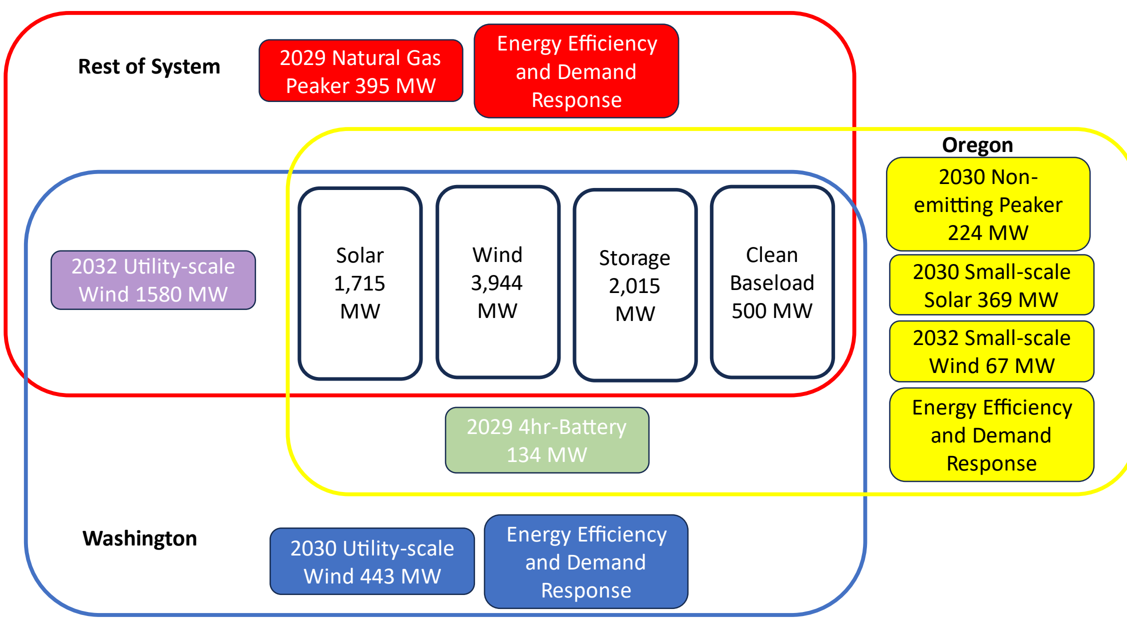
Much of the preferred portfolio closely matches the least cost systemwide MM portfolio. The preferred portfolio moves 134 megawatts of battery early into 2029 from 2031, 2036 and 2037, and adds a total of 101 megawatts of battery storage over the system view. Total peaking is 43 megawatts higher in the preferred portfolio than in the system view, although 224 megawatts of gas peaking units are assumed to be non-emitting to meet state requirements, whereas the system-wide portfolio assumed all gas peaking is fueled by natural gas. The integration of Oregon and Washington energy efficiency and demand response adds 109 total megawatts. Washington's 443 megawatts of situs wind comes online in 2030, and Oregon's small-scale wind and solar are integrated into 2030-2033, reducing Oregon's share of utility-scale solar in 2033, 2034, and 2037. No other changes were indicated by state-level requirements, and the situs wind and small-scale renewables are all assumed to be situs to Oregon and Washington. Table 6.1 below shows changes to the systemwide portfolio for state compliance, color coded by which state required the change.

Table 6.1 – Preferred Portfolio Resource Integrations (Installed Capacity, MW)

Situs/Partial Share Resources	Oregon	Washington	OR and WA	WA and Sys	OR and Sys	No OR/WA								
Category	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Natural Gas	395	-	-	-	-	-	-	-	-	836	-	3122	749	-
NonEmitting Peaker	-	224	-	-	-	-	-	-	59	-	-	-	-	-
Utility Scale Wind	-	443	-	1580	15	-	-	-	-	-	-	-	-	-
Small Scale Wind	-	-	-	67	172	-	-	-	-	-	-	-	-	-
Utility Scale Solar	-	-	-	-	449	93	-	-	1009	-	-	-	-	-
Small Scale Solar	-	369	5	-	-	-	-	-	109	-	-	-	-	-
Clean Baseload	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4hr Battery	134	-	11	8	-	3	-	-	78	-	-	17	9	-
Storage (Long Duration)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	529	1036	16	1655	636	96	0	0	1255	836	0	3139	758	0

Figure 6.5 below shows allocations through 2032 of all resources in the preferred portfolio using similar Venn diagram imagery to Figure 6.3, above.

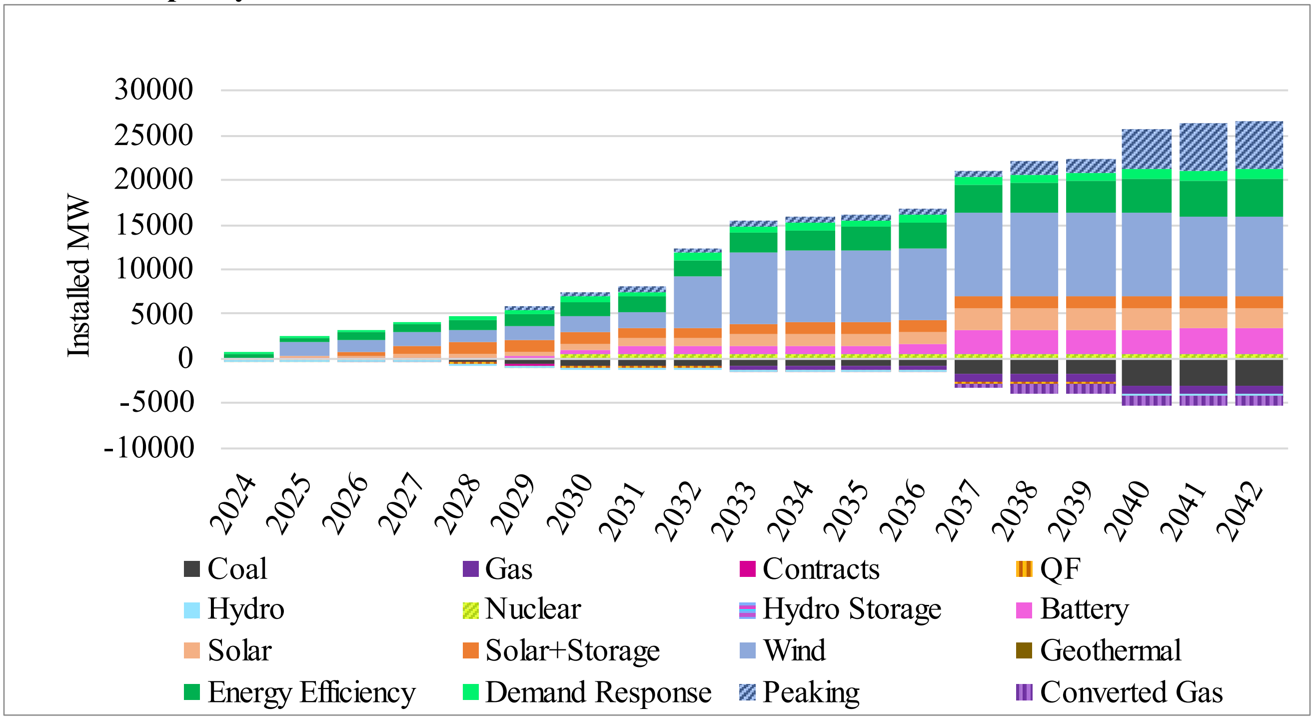
Figure 6.5 – Allocation of the 2023 IRP Update Preferred Portfolio Through 2032



Preferred Portfolio Results

Figure 6.6 reports that PacifiCorp's 2023 IRP Update integrated preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, Natrium™ advanced nuclear, and peaking resources.

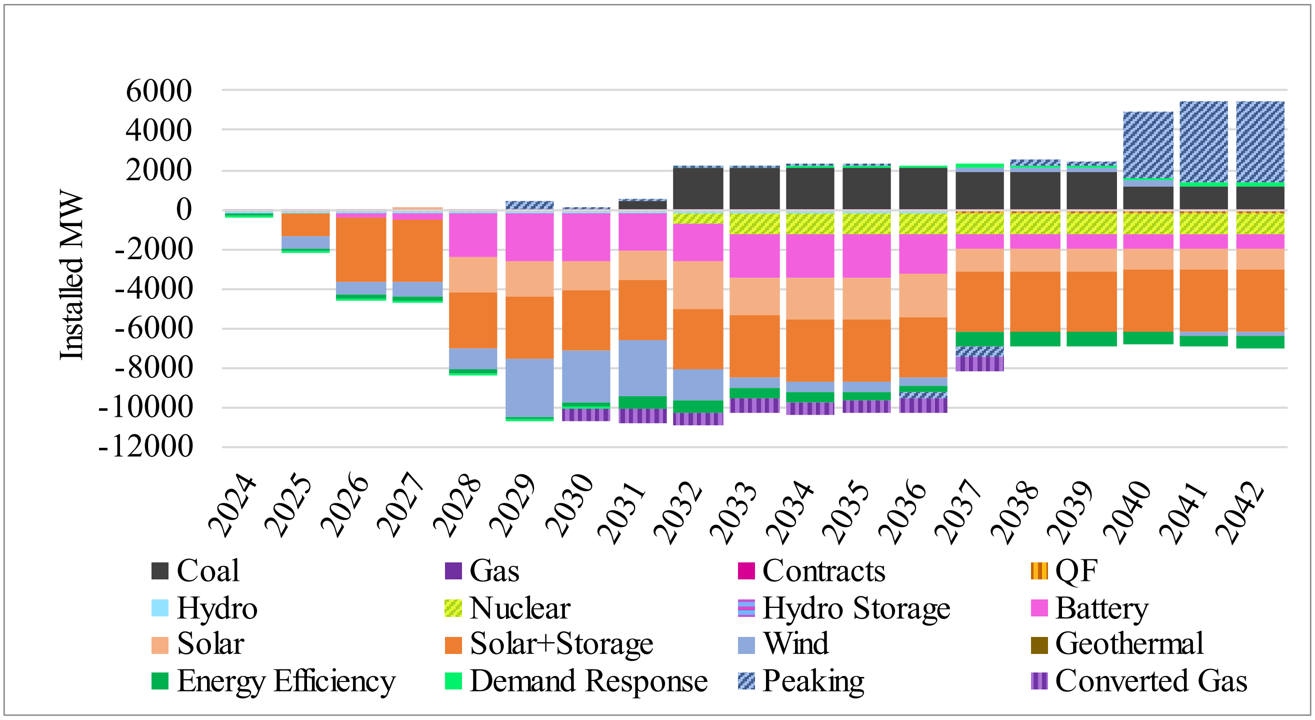
Figure 6.6 – 2023 IRP Update All-State Preferred Portfolio Cumulative Changes in Installed Capacity



*Note: "Coal" includes both minority and majority owned coal resources, including Jim Bridger Units 3 and 4 with CCUS. "Coal" does not include coal resources converted to gas. Coal resources converted to gas are categorized under "Converted Gas" and only show at retirement, as the conversion does not increase the installed capacity of the resource. "Gas" includes only existing gas resources. New gas peaking and new hydrogen peaking resources are grouped under "Peaking". "Nuclear" includes only the Natrium™ advanced nuclear project.

Figure 6.7 summarizes the annual nameplate capacity in the 2023 IRP Update relative to the 2023 IRP preferred portfolio for the 19-year period 2024 through 2042. Consistent with the updates to the OTR and changes in gas peaking unit assumptions, significant differences can be seen between the 2023 IRP and the 2023 IRP update.

Figure 6.7 – Cumulative Increase/(Decrease) in 2023 IRP Update less 2023 IRP Preferred Portfolio



As a result of EPA's approval of Wyoming's OTR plan and the stay of EPA's disapproval of Utah's OTR plan, certain coal units' end-of-life assumptions vary from the 2023 IRP. There is a reduction in early solar and wind resources given the existing thermal fleet's ability to operate with fewer restrictions. The adjustment to include gas peaking resources as convertible to a non-emitting fuel in the future led to an increased selection of peaking units. This selection offsets some renewables due to the peaking units' ability to generate as needed.

Present Value Revenue Requirement

The 2023 IRP Update Preferred Portfolio represents the least cost study over the 20-year study horizon, with a PVRR of $32.807b under the MM price policy scenario. While the overall PVRR of the preferred portfolio is lowest during the study horizon, the final years of the portfolio represent a cost when compared to the unconstrained, systemwide study. From 2040 to 2042, the preferred portfolio is, on average, $72m more costly each year than the unconstrained system portfolio. This indicates that the resources necessary for individual state compliance added relative to the unconstrained system portfolio would not be cost-effective over their economic lives.

In addition to evaluating portfolios under the MM price policy scenario, select variant studies were also modeled under each of the other price curves. Under the Medium Gas, No CO_2 price curve, and the Low Gas, No CO_2 price curve, the systemwide portfolio is least-cost. In other words, the preferred portfolio proves to be the most robust when different future price environments are considered. Tables showing the preferred portfolio and select variants run under the different price policy assumptions appear at the end of the chapter.

Transmission Upgrades

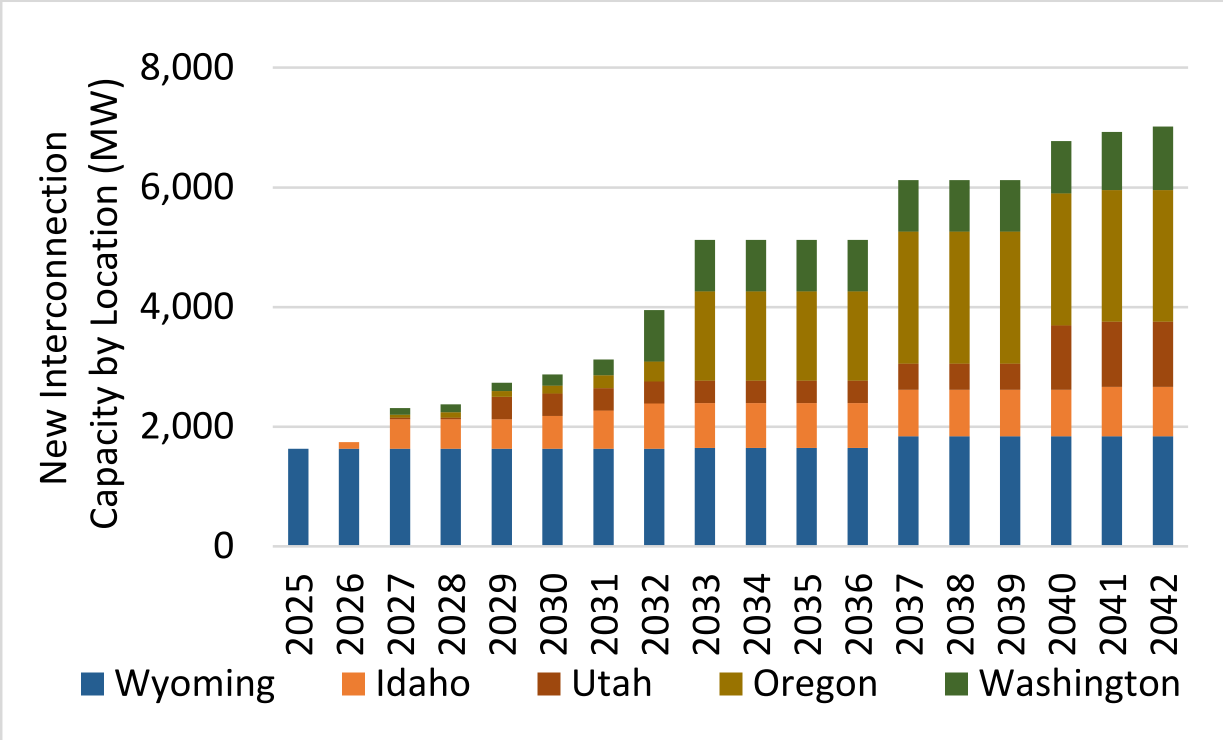
To facilitate the delivery of new resources to PacifiCorp customers across the West, the 2023 IRP Update preferred portfolio includes additional transmission investment. As supported by needs established in previous IRPs, PacifiCorp is finalizing construction of the Energy Gateway South and Energy Gateway West Sub-Segment D1 transmission projects and partnering with Idaho Power to build the B2H transmission project, which is expected to come online in the 2026-2027 timeframe. B2H is a 290-mile high-voltage 500 kilovolt transmission line that connects the Longhorn substation near the town of Boardman in Oregon to the Hemingway substation in Idaho. 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.

In the 2023 IRP Update, many transmission upgrades and the accompanying resources reflect the results of PacifiCorp's generator interconnection "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, transmission upgrades and resource additions in the 2023 IRP Update preferred portfolio consider cluster study requests submitted in the past several years. Additional transmission expansion projects can include development of new segments and exploration of new routes that have connections to other areas. Figure 6.8 summarizes the new interconnection capacity selected to facilitate new generation resources identified as part of the 2023 IRP Update preferred portfolio.

In addition to providing increased interconnection capacity, transmission upgrades are also expected to allow for increased transfer capability between different areas of PacifiCorp's system. The 2023 IRP Update preferred portfolio includes portions of the following transmission upgrades between the following areas within the IRP topology. Note that modeling for the 2023 IRP Update allowed for partial selection of lines, though that does not indicate that these lines would be uneconomic if built in their entirety. Given the timing identified primarily in the second half of the IRP study horizon, these opportunities will continue to be explored in the future.

- Walla Walla to Yakima.
- Gateway Sub-Segment D3: provides direct transfers between Jim Bridger and Borah (Populus), but with supporting projects, also facilitates transfers between Wyoming East and Jim Bridger and between Borah and Utah North.
- Incremental Gateway Segments: Segments D2.2, D1.2, and Gateway South 2 would be the second iteration of existing or soon to be in service segments from the original Gateway plan and would provide additional transfer capability between Wyoming East and Bridger and between Wyoming East and Clover.
- Oregon 500 kilovolt upgrades: several 500 kilovolt upgrades and supporting projects would connect Portland-North Coast, Willamette Valley, Southern Oregon, and Central Oregon.
- East-West transfers: together, B2H 2 and Gateway Segment E would further increase transfer capability between PacifiCorp's east and west balancing authority areas.

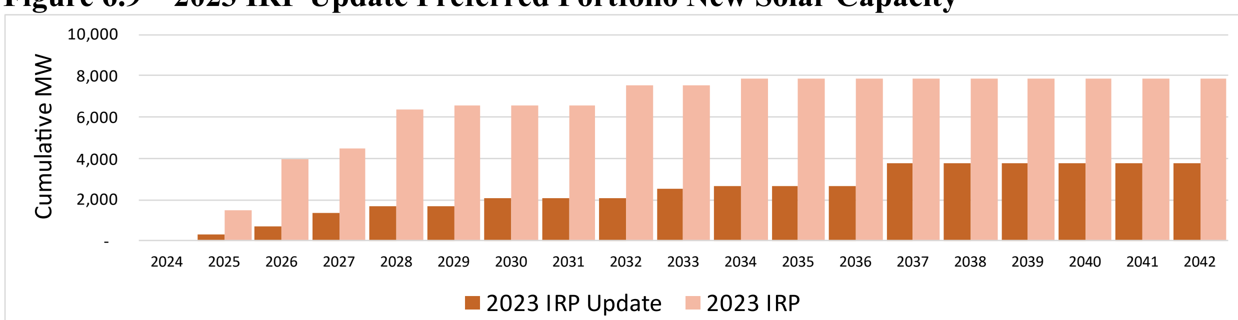
Figure 6.8 – New Interconnection Capacity by Location, 2023 IRP Update Preferred Portfolio



New Solar Resources

The 2023 IRP Update preferred portfolio includes 2,084 megawatts of solar by the end of 2030, and 3,749 megawatts of new solar is online by 2037, as shown in Figure 6.9. While not shown in Figure 6.9, the company has also previously contracted for one gigawatt of solar resources with commercial operation dates between 2024 and 2026 for customer-directed voluntary renewable procurement programs.

Figure 6.9 – 2023 IRP Update Preferred Portfolio New Solar Capacity*

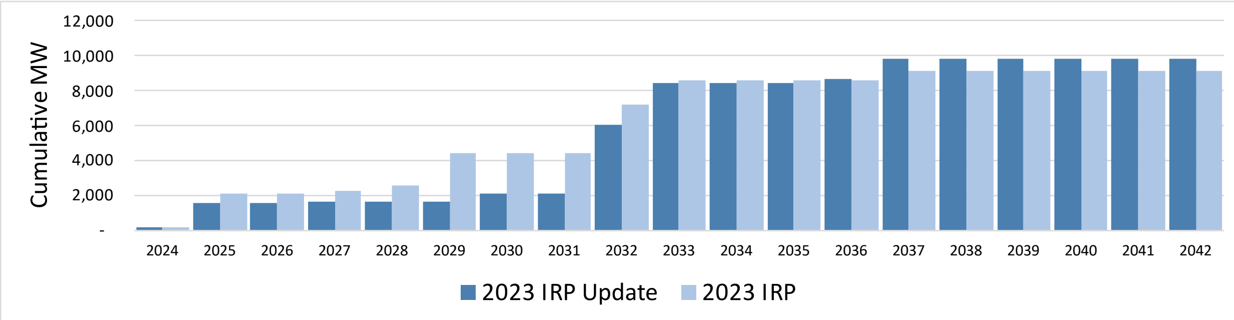


* 2023 IRP Update solar capacity shown in the figure includes committed solar resources shown in 2025 and 2026. Resources are shown in the first full year of operation (the year after the year-online dates). This total includes 374 megawatts of small scale solar to meet Oregon requirements.

New Wind Resources

As shown in Figure 6.10, by 2032, PacifiCorp's 2023 IRP Update preferred portfolio includes 6,034 megawatts of new wind resources, and more than 9,800 megawatts of new wind resources by 2037.

Figure 6.10 – 2023 IRP Update Preferred Portfolio New Wind Capacity*

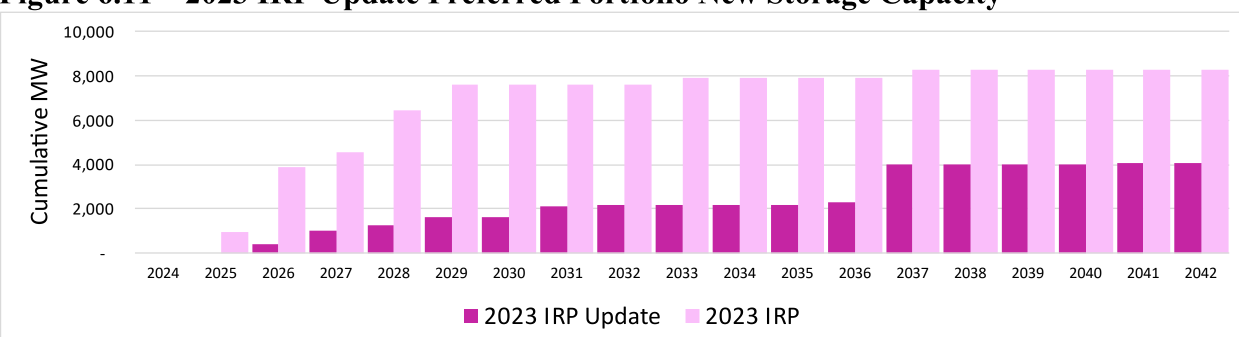


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates). This figure includes 254 megawatts of small-scale wind to meet Oregon requirements, and an additional 443 megawatts of utility scale wind to meet Washington requirements.

New Storage Resources

As shown in Figure 6.11, the 2023 IRP Update preferred portfolio includes 1,626 megawatts of new storage capacity by the end of year 2029 and more than 4,000 megawatts by 2037.

Figure 6.11 – 2023 IRP Update Preferred Portfolio New Storage Capacity*

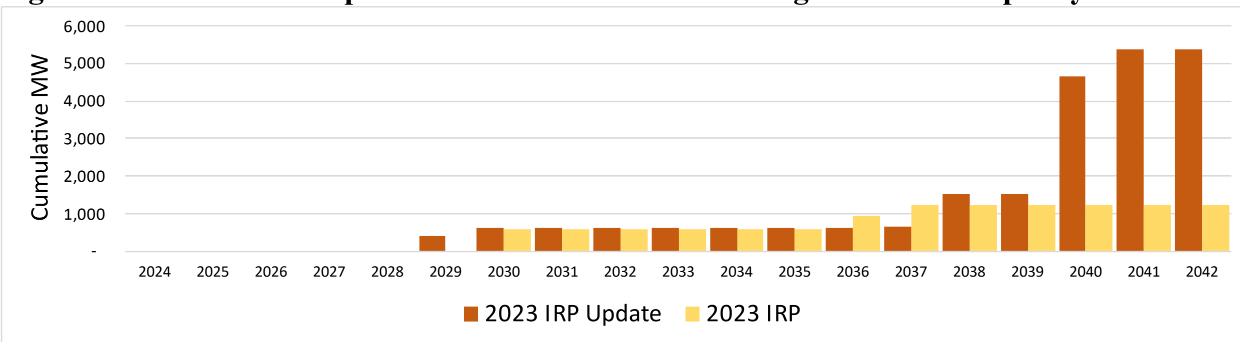


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates). This figure includes a total of 101 megawatts of storage resources required by Oregon and Washington for compliance

Peaking Capacity

The 2023 IRP Update continues to indicate the need for flexible peaking capacity to achieve reliability and minimize risk. A key change since the filing of the 2023 IRP is the addition of peaking capacity in the form of natural gas resources capable of operating with 100% hydrogen fuel. The inclusion of this technology also guards against the future risk of increasingly constrained emissions and future policy requirements.

Figure 6.12 – 2023 IRP Update Preferred Portfolio Peaking Resources Capacity*

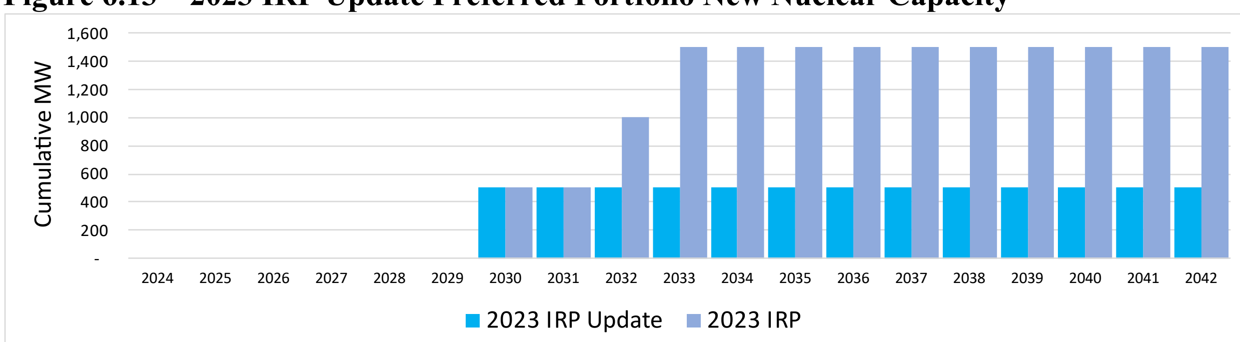


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates). This figure includes 224 megawatts of peaking units for Oregon compliance that can only run on clean fuel.

Nuclear Capacity

The 2023 IRP Update continues to show the value associated with the Natrium™ Demonstration Project which provides a significant non-emitting resource. A key change since the filing of the 2023 IRP is the stay of the EPA's disapproval of Utah's OTR plan and subsequent ability of the existing thermal fleet to operate with fewer restrictions as a dispatchable resource. Although additional advanced nuclear resources beyond the Natrium™ Demonstration Project are not selected in this update, PacifiCorp is continually updating advanced nuclear resource cost estimates as they become available.

Figure 6.13 – 2023 IRP Update Preferred Portfolio New Nuclear Capacity



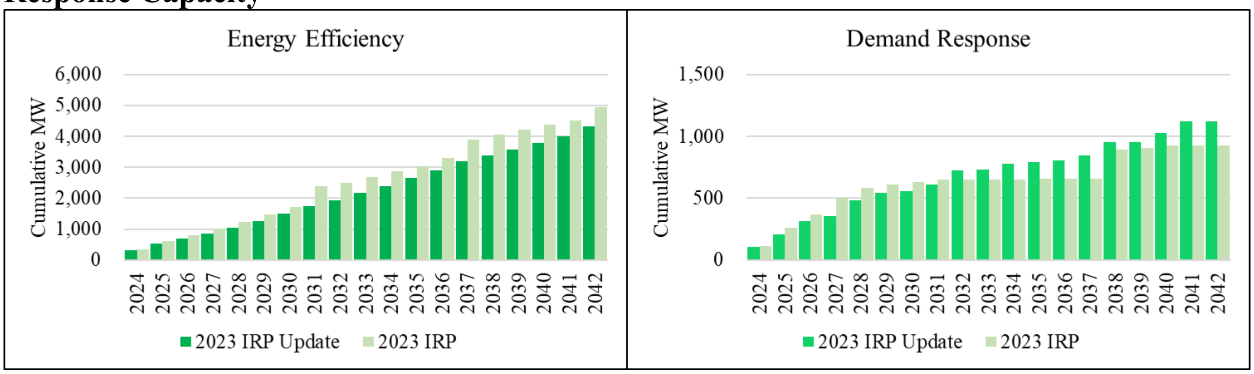
Demand-Side Management

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. The optimal determination of DSM resources results in selecting all cost-effective DSM as a core function of IRP modeling. 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 Update.

DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 6.14 compares total energy efficiency capacity savings in the 2023 IRP Update preferred portfolio relative to the 2023 IRP preferred portfolio and includes 4,326 megawatts 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 6.14 compares cumulative demand response program capacity in the 2023 IRP Update preferred portfolio relative to the 2023 IRP preferred portfolio and does not include capacity from existing programs. The 2023 IRP Update has a cumulative capacity of incremental demand response programs reaching 1,123 megawatts by 2042 which represents a 21% increase relative to the 2023 IRP.

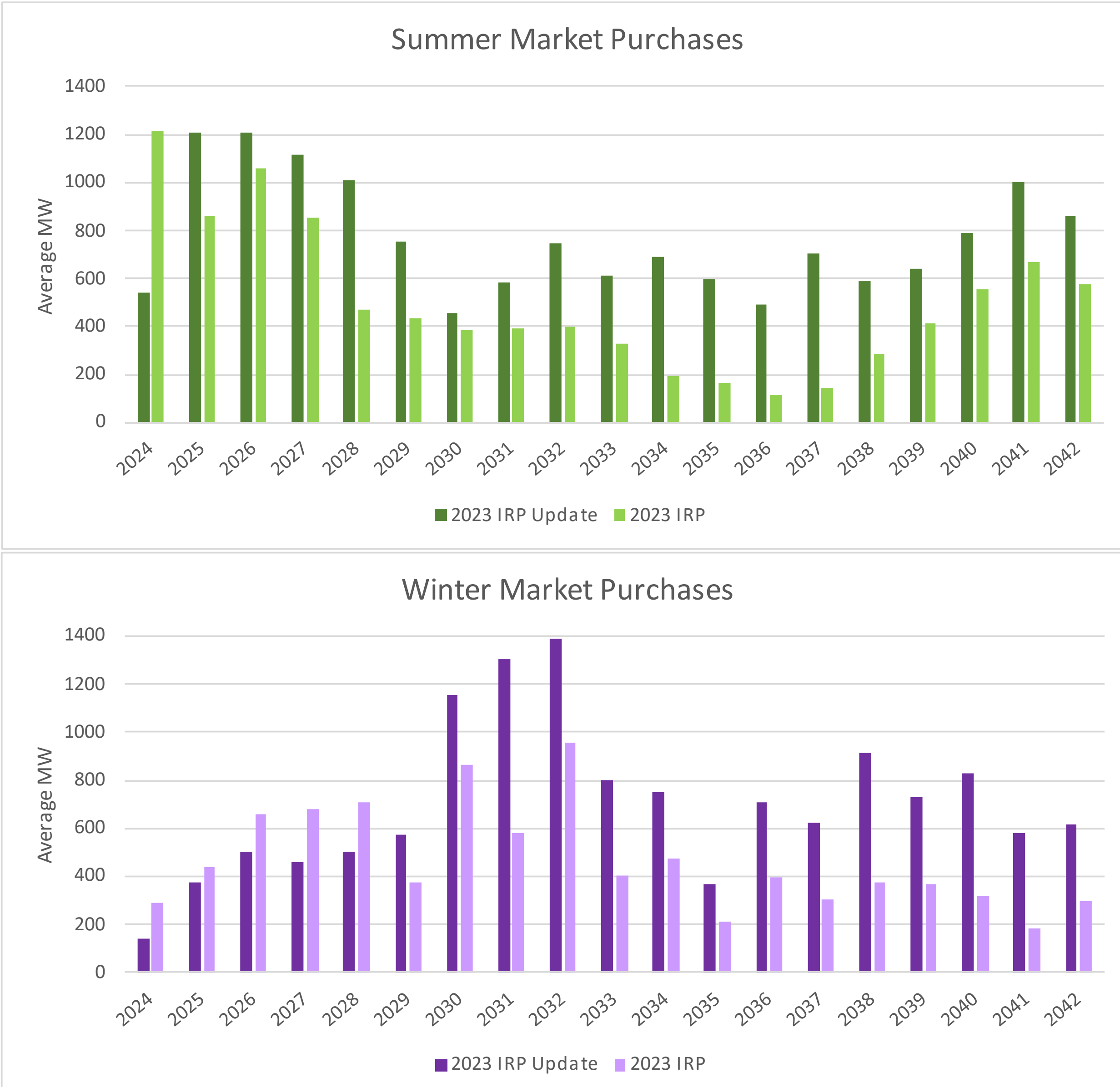
Figure 6.14 – 2023 IRP Update Preferred Portfolio Energy Efficiency and Demand Response Capacity



Market Activity

Subsequent to the filing of the 2023 IRP, the EPA's approval of Wyoming's state OTR plan and the stay of EPA's disapproval of Utah's state OTR plan removed the restrictions that limited energy production in the summer from natural gas and coal-fueled resources in Wyoming and Utah. In the absence of the OTR, market purchases can cost-effectively replace some of the incremental renewable resources that were indicated in the 2023 IRP preferred portfolio, leading to higher relative market activity, as shown in Figure 6.15 below. In addition, a 500 megawatt capacity Wyoming market has been added in the 2023 IRP update, representing the ongoing ability to access diverse (and potentially new) regional markets as discussed in Chapter 3.

Figure 6.15 – 2023 IRP Update Preferred Portfolio Market Purchases



*Note: "Summer Market Purchases" includes purchases from June through September while "Winter Market Purchases" includes purchases from December and January. While most data for tables and figures in this document comes from LT capacity expansion model results, this figure uses ST model results. For market data, it is appropriate to use ST model results because the ST model is run with an hourly granularity which more accurately represents the energy needed to meet load obligations compared to the less granular LT capacity expansion model.

Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. The operating capabilities of these facilities have been able to adapt to changes in the planning environment. For example, PacifiCorp has been able to lower operating minimums and optimize coal dispatch through the Energy Imbalance Market (EIM). This in turn has enabled the company to both reduce fuel consumption and associated costs and emissions by increasingly buying 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. EPA's approval of Wyoming's ozone plan and the stay of EPA's disapproval of Utah's ozone plan results in fewer restrictions on coal-fired operation than were assumed in the 2023 IRP. With these updates, Utah coal resources are no longer planned to retire early, as shown in Table 6.2. Hunter and Huntington coal unit retirements, specifically, have returned to the schedule that had been previously indicated by PacifiCorp's 2021 IRP.

Table 6.2 – Coal Unit Retirements in the 2023 IRP and 2023 IRP Update

Coal			
Unit	2023 IRP Retirement Year (12/31/__)	2023 IRP Update Retirement Year (12/31/__)	Delta to 2023 IRP (Years)
	As Selected	As Selected	
Colstrip 3	2025	2025	-
Colstrip 4	2029	2029	-
Craig 1	2025	2025	-
Craig 2	2028	2028	-
DaveJohnston 1	2028	2028	-
DaveJohnston 2	2028	2028	-
DaveJohnston 3	2027	2027	-
DaveJohnston 4	2039	2039	-
Hayden 1	2028	2028	-
Hayden 2	2027	2027	-
Hunter 1	2031	2042	11
Hunter 2	2032	2042	10
Hunter 3	2032	2042	10
Huntington 1	2032	2036	4
Huntington 2	2032	2036	4
JimBridger 1	2037	2037	-
JimBridger 2	2037	2037	-
JimBridger 3	2037	2039	2
JimBridger 4	2037	2039	2
Naughton 1	2036	2036	-
Naughton 2	2036	2036	-
Wyodak	2039	2039	-

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

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

- 2028 = Jim Bridger Units 3-4, retrofitted with carbon capture technology in 2028, operates through 2039 (converted to gas conversion in 2030 and retired in 2037 in the 2023 IRP; unit life is extended by 2 years to capture 12 full years of investment tax credits)
- 2028 = Dave Johnston Units 1-2 retirement (same as in the 2023 IRP)
- 2028 = Craig Unit 2 retirement (same as in the 2023 IRP)
- 2028 = Hayden Unit 1 retirement (same as in the 2023 IRP)
- 2029 = Colstrip Unit 4 exit, Colstrip Unit 3 share is consolidated into Colstrip Unit 4 in 2025 (same as in the 2023 IRP)
- 2036 = Huntington Units 1-2 retirement, no emissions controls (SNCR installation in 2026, operating through 2032 in the 2023 IRP)
- 2039 = Dave Johnston Unit 4 retirement (same as in 2023 IRP)
- 2039 = Wyodak retirement, no emissions controls (SNCR installation in 2026, operating through 2039 in the 2023 IRP)
- 2042 = Hunter Units 1-3 retirement, no emissions controls (SNCR installation in 2026, operating through 2031 and 2032 in the 2023 IRP)

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Table 6.3 – Comparison of 2023 IRP Update with 2023 IRP Preferred Portfolio (Megawatts)

2023 IRP Update

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																				
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking	-	-	-	-	-	395	224	-	-	-	-	-	-	59	836	-	3,122	749	-	5,385
DSM - Energy Efficiency	151	211	160	175	192	219	224	250	196	224	230	257	252	292	187	178	218	231	314	4,161
DSM - Demand Response	38	98	110	35	133	61	11	56	112	9	42	14	12	43	108	-	71	95	3	1,051
Renewable - Wind	194	1,361	-	79	-	-	443	5	3,952	2,354	-	-	228	1,202	-	-	-	-	-	9,818
Renewable - Utility Solar	-	300	398	654	363	-	369	5	-	449	93	-	-	1,118	-	-	-	-	14	3,763
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	400	565	297	337	-	521	21	-	3	-	152	1,694	-	-	17	9	-	4,016
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	35
Nuclear	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	500
Existing Unit Changes																				
Coal Plant Retirements - Minority Owned	-	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	-	(220)	(205)	-	-	-	-	-	-	-	(909)	-	-	(598)	-	-	(1,932)
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(699)	-	-	(699)
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	(357)	(713)	-	-	-	-	(1,070)
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	(358)	-	-	-	(484)	-	-	-	-	-	(842)
Retire - Hydro	(47)	-	-	-	-	-	-	-	-	-	-	-	-	(7)	-	-	-	-	-	(54)
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(32)	-	-	-	-	(32)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(519)	-	(519)
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	(18)	-	-	-	-	-	(18)
Expire - Wind PPA	(41)	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	-	-	(405)
Expire - Solar PPA	-	-	-	-	(2)	-	-	-	(7)	-	-	-	-	(73)	-	-	-	(4)	-	(86)
Expire - QF	(50)	-	(0)	(1)	-	(3)	-	-	-	-	-	-	(0)	(1)	-	-	-	(1)	(1)	(57)
Expire - Other	(161)	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	-	-	(161)
Total	**84**	**1,970**	**948**	**1,507**	**730**	**682**	**1,524**	**637**	**4,274**	**2,678**	**368**	**271**	**644**	**2,558**	**386**	**178**	**2,139**	**559**	**330**	

2023 IRP Update less 2023 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																				
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peaking	-	-	-	-	-	395	(382)	-	-	-	-	-	(345)	(230)	836	-	3,122	749	-	4,145
DSM - Energy Efficiency	(69)	(48)	(37)	(40)	(27)	(17)	(37)	(415)	84	49	46	96	(25)	(301)	36	7	49	91	(112)	(670)
DSM - Demand Response	(1)	(54)	-	(98)	52	34	(4)	34	112	9	42	7	12	43	(125)	(19)	51	95	3	193
Renewable - Wind	-	(576)	-	(22)	(300)	(1,900)	443	5	1,169	994	-	-	228	662	-	-	-	-	-	703
Renewable - Utility Solar	-	(1,169)	(2,126)	171	(1,544)	(200)	369	5	(972)	449	(207)	-	-	1,118	-	-	-	-	14	(4,092)
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	(954)	(2,529)	(63)	(1,603)	(812)	-	521	21	(150)	3	-	152	1,494	-	-	17	9	-	(3,894)
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	(150)	-	-	-	(200)	-	-	-	-	-	(350)
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	(8)	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-
Nuclear	-	-	-	-	-	-	-	-	(500)	(500)	-	-	-	-	-	-	-	-	-	(1,000)
Existing Unit Changes																				
Coal Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	(909)	-	-		-	-	(909)
JB34 Gas Convert vs CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	699	-	(699)	-	-	(0)
Coal - SNCR	-	-	-	-	-	-	-	-	418	1,649	-	-	-	-	-	-		-	-	2,067
Total	**(70)**	**(2,801)**	**(4,700)**	**(52)**	**(3,422)**	**(2,500)**	**389**	**150**	**332**	**2,350**	**(116)**	**103**	**22**	**1,677**	**1,446**	**(12)**	**2,548**	**944**	**(95)**	

*For the compare, existing unit changes were consolidated for clarity

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Table 6.4 – 2023 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

East	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Thermal	6,805	6,852	6,769	6,769	6,546	6,234	6,234	6,234	6,234	6,234
Peaker	352	352	352	352	352	352	352	352	352	0
Hydroelectric	60	60	60	60	60	60	60	60	60	60
Wind	504	716	701	701	701	701	681	649	649	649
Solar	279	356	600	595	591	586	582	578	574	570
Other Renewable	41	41	41	41	41	41	41	41	41	41
Storage	1	1	496	496	496	496	496	496	496	496
Purchase	120	120	120	120	120	120	120	120	120	120
Qualifying Facilities	359	358	356	354	352	350	348	346	343	334
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,521**	**8,855**	**9,495**	**9,489**	**9,260**	**8,941**	**8,914**	**8,877**	**8,869**	**8,505**
Market Purchases										
Peaker	0	0	0	0	0	372	584	584	584	584
Wind	14	14	14	28	28	28	118	118	648	757
Solar	0	0	0	81	162	162	262	264	264	386
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	245	428	608	608	684	694	694
Nuclear	0	0	0	0	0	0	485	485	485	485
East Planned Resources	**14**	**14**	**14**	**353**	**618**	**1,170**	**2,057**	**2,134**	**2,675**	**2,906**
East Total Resources	**8,534**	**8,869**	**9,509**	**9,842**	**9,877**	**10,111**	**10,971**	**11,011**	**11,544**	**11,411**
Load	7,679	7,947	7,877	8,137	8,556	8,727	8,906	9,181	8,972	9,105
Private Generation	(102)	(143)	(111)	(141)	(174)	(213)	(256)	(304)	(151)	(175)
Existing - Demand Response	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)
New Demand Response	(5)	(33)	(55)	(63)	(112)	(122)	(122)	(142)	(161)	(161)
New Energy Efficiency	(132)	(217)	(269)	(343)	(450)	(534)	(614)	(743)	(814)	(932)
East Total obligation	**6,946**	**7,060**	**6,948**	**7,097**	**7,326**	**7,365**	**7,420**	**7,498**	**7,351**	**7,343**
East Reserve Margin	23%	26%	37%	39%	35%	37%	48%	47%	57%	55%
West										
Thermal	878	878	872	872	872	872	736	736	736	736
Peaker	0	0	0	0	0	0	0	0	0	0
Hydroelectric	691	695	692	700	700	699	699	699	699	699
Wind	56	56	56	56	56	56	56	56	56	56
Solar	54	54	54	53	53	53	53	52	52	52
Other Renewable	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	146	193	192	192	191	190	190	190	183	183
Sale	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
West Existing Resources	**1,818**	**1,868**	**1,860**	**1,866**	**1,866**	**1,864**	**1,727**	**1,726**	**1,720**	**1,719**
Market Purchases	1,413	1,235	508	256	478	348	0	0	0	0
Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	12	13	277	706
Solar	0	0	0	54	65	65	65	65	65	65
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	27	218	280	376	376	680	688	688
Nuclear	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,413**	**1,235**	**535**	**528**	**823**	**789**	**453**	**759**	**1,030**	**1,459**
West Total Resources	**3,231**	**3,103**	**2,395**	**2,394**	**2,688**	**2,653**	**2,180**	**2,485**	**2,750**	**3,178**
Load	3,667	3,842	3,931	4,111	4,257	4,466	4,593	4,817	4,813	4,870
Private Generation	(45)	(69)	(68)	(89)	(111)	(137)	(166)	(201)	(111)	(130)
Existing - Demand Response	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
New Demand Response	(71)	(94)	(122)	(128)	(155)	(173)	(173)	(187)	(192)	(193)
New Energy Efficiency	(64)	(123)	(134)	(142)	(176)	(205)	(211)	(263)	(252)	(269)
West Total obligation	**3,466**	**3,535**	**3,586**	**3,731**	**3,794**	**3,931**	**4,022**	**4,144**	**4,237**	**4,257**
West Reserve Margin	-7%	-12%	-33%	-36%	-29%	-33%	-46%	-40%	-35%	-25%
System										
Total Resources	11,766	11,972	11,904	12,236	12,566	12,764	13,152	13,496	14,293	14,589
Obligation	10,412	10,595	10,534	10,828	11,120	11,295	11,442	11,642	11,588	11,600
Planning Reverve Margin (13%)	1,354	1,377	1,369	1,408	1,446	1,468	1,487	1,513	1,506	1,508
Obligation + Reserves	11,766	11,972	11,904	12,236	12,566	12,764	12,930	13,155	13,094	13,108
System Position	0	0	0	0	0	0	222	340	1,199	1,480
Reserve Margin	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**15%**	**16%**	**23%**	**26%**

Table 6.4 (Cont.) – 2023 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

East	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	6,234	6,234	6,234	4,802	4,104	4,104	2,890	2,890	2,890
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	60	60	60	60	60	59	60	60	60
Wind	649	649	649	649	649	649	649	547	547
Solar	567	563	559	525	521	518	515	511	508
Other Renewable	41	41	41	41	13	13	13	13	13
Storage	495	495	495	495	495	495	495	495	495
Purchase	120	120	120	120	120	120	120	120	120
Qualifying Facilities	330	328	323	272	270	263	262	261	259
Sale	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,496**	**8,490**	**8,481**	**6,965**	**6,233**	**6,221**	**5,003**	**4,897**	**4,892**
Market Purchases	0	0	0	0	0	0	0	0	0
Peaker	584	584	584	640	1,429	1,429	4,377	5,084	5,084
Wind	757	757	757	814	814	814	814	814	814
Solar	411	411	411	715	715	715	715	715	718
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	695	695	705	1,484	1,484	1,484	1,484	1,484	1,484
Nuclear	485	485	485	485	485	485	485	485	485
East Planned Resources	**2,933**	**2,933**	**2,943**	**4,138**	**4,928**	**4,928**	**7,876**	**8,583**	**8,586**
East Total Resources	**11,429**	**11,423**	**11,424**	**11,103**	**11,161**	**11,149**	**12,879**	**13,479**	**13,477**
Load	9,223	9,361	9,564	9,726	9,867	9,980	10,112	10,248	10,428
Private Generation	(197)	(220)	(242)	(265)	(287)	(309)	(330)	(352)	(374)
Existing - Demand Response	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)	(494)
New Demand Response	(178)	(186)	(194)	(224)	(261)	(261)	(283)	(349)	(349)
New Energy Efficiency	(1,037)	(1,124)	(1,209)	(1,317)	(1,400)	(1,498)	(1,589)	(1,653)	(1,752)
East Total obligation	**7,317**	**7,338**	**7,424**	**7,425**	**7,425**	**7,418**	**7,416**	**7,400**	**7,459**
East Reserve Margin	56%	56%	54%	50%	50%	50%	74%	82%	81%
West									
Thermal	736	736	736	500	500	500	500	500	500
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	699	699	699	699	699	699	699	699	707
Other Renewable	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0
Qualifying Facilities	182	182	181	162	160	159	159	158	159
Sale	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)	(7)
West Existing Resources	**1,611**	**1,610**	**1,610**	**1,354**	**1,352**	**1,351**	**1,351**	**1,350**	**1,360**
Market Purchases	0	0	0	0	0	0	0	0	0
Peaker	0	0	0	0	0	0	0	0	0
Wind	706	706	743	952	952	952	952	952	952
Solar	65	65	65	65	65	65	65	65	65
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	688	688	787	1,345	1,345	1,345	1,365	1,372	1,372
Nuclear	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,459**	**1,459**	**1,595**	**2,362**	**2,362**	**2,362**	**2,383**	**2,389**	**2,389**
West Total Resources	**3,070**	**3,070**	**3,205**	**3,716**	**3,714**	**3,713**	**3,733**	**3,739**	**3,749**
Load	4,929	4,995	5,068	5,176	5,246	5,318	5,384	5,461	5,647
Private Generation	(148)	(163)	(178)	(193)	(208)	(222)	(236)	(250)	(264)
Existing - Demand Response	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
New Demand Response	(200)	(201)	(202)	(206)	(229)	(229)	(257)	(264)	(265)
New Energy Efficiency	(299)	(322)	(314)	(357)	(355)	(366)	(396)	(391)	(429)
West Total obligation	**4,261**	**4,288**	**4,353**	**4,399**	**4,433**	**4,481**	**4,474**	**4,535**	**4,668**
West Reserve Margin	-28%	-28%	-26%	-16%	-16%	-17%	-17%	-18%	-20%
System									
Total Resources	14,499	14,492	14,629	14,819	14,875	14,862	16,612	17,219	17,226
Obligation	11,578	11,626	11,778	11,825	11,858	11,899	11,889	11,935	12,127
Planning Reverve Margin (13%)	1,505	1,511	1,531	1,537	1,541	1,547	1,546	1,552	1,577
Obligation + Reserves	13,083	13,137	13,309	13,362	13,399	13,446	13,435	13,487	13,704
System Position	1,416	1,356	1,320	1,458	1,476	1,416	3,177	3,732	3,522
Reserve Margin	**25%**	**25%**	**24%**	**25%**	**25%**	**25%**	**40%**	**44%**	**42%**

Table 6.5 – 2023 IRP Update Winter Capacity Load and Resource Balance (Megawatts)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
East										
Thermal	6,828	6,875	6,795	6,795	6,578	6,264	6,264	6,264	6,264	6,264
Peaker	323	323	323	323	323	323	323	323	323	0
Hydroelectric	36	36	36	36	36	36	36	36	36	36
Wind	442	602	594	594	594	594	579	552	552	552
Solar	197	288	408	405	402	399	396	393	391	388
Other Renewable	34	34	34	34	34	34	34	34	34	34
Storage	1	1	468	468	468	468	468	468	468	468
Purchase	172	172	172	172	172	172	172	172	172	172
Qualifying Facilities	284	283	281	279	278	276	275	273	271	263
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,317**	**8,613**	**9,111**	**9,107**	**8,884**	**8,566**	**8,547**	**8,515**	**8,510**	**8,177**
Market Purchases	0	0	0	0	0	0	0	0	0	0
Peaker	0	0	0	0	0	372	584	584	584	584
Wind	50	51	51	66	66	66	141	141	640	737
Solar	0	0	0	50	109	109	187	188	188	284
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	259	432	602	602	686	696	696
Nuclear	0	0	0	0	0	0	475	475	475	475
East Planned Resources	**50**	**51**	**51**	**376**	**608**	**1,150**	**1,990**	**2,075**	**2,583**	**2,776**
East Total Resources	**8,367**	**8,664**	**9,163**	**9,482**	**9,492**	**9,717**	**10,537**	**10,590**	**11,093**	**10,953**
Load	5,724	6,097	6,171	6,444	6,754	6,700	6,872	7,145	7,214	7,387
Private Generation	(2)	0	0	0	0	(8)	(10)	0	0	0
Existing - Demand Response	(462)	(462)	(462)	(462)	(462)	(462)	(462)	(462)	(462)	(462)
New Demand Response	(5)	(20)	(35)	(39)	(66)	(72)	(72)	(84)	(97)	(97)
New Energy Efficiency	(102)	(111)	(172)	(232)	(299)	(470)	(569)	(529)	(615)	(693)
East Total obligation	**5,154**	**5,504**	**5,502**	**5,711**	**5,927**	**5,688**	**5,759**	**6,070**	**6,040**	**6,135**
East Reserve Margin	62%	57%	67%	66%	60%	71%	83%	74%	84%	79%
West										
Thermal	878	878	874	874	874	874	736	736	736	736
Peaker	0	0	0	0	0	0	0	0	0	0
Hydroelectric	538	544	542	555	556	555	555	553	554	554
Wind	74	74	74	74	74	74	74	74	74	74
Solar	44	43	43	43	42	42	42	41	40	40
Other Renewable	0	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	116	127	127	127	127	126	126	126	120	120
Sale	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
West Existing Resources	**1,639**	**1,657**	**1,650**	**1,662**	**1,662**	**1,660**	**1,522**	**1,520**	**1,514**	**1,513**
Market Purchases	0	0	0	0	0	0	0	0	0	0
Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	11	12	256	617
Solar	0	0	0	41	48	48	48	48	48	48
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	0	0	27	250	324	441	441	837	846	846
Nuclear	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**0**	**0**	**27**	**291**	**372**	**489**	**500**	**897**	**1,151**	**1,511**
West Total Resources	**1,639**	**1,657**	**1,676**	**1,953**	**2,034**	**2,149**	**2,022**	**2,417**	**2,665**	**3,024**
Load	3,711	3,577	3,676	3,858	4,024	4,476	4,539	4,419	4,475	4,524
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
New Demand Response	(60)	(78)	(98)	(101)	(131)	(165)	(165)	(180)	(182)	(184)
New Energy Efficiency	(89)	(96)	(126)	(167)	(221)	(324)	(378)	(341)	(368)	(415)
West Total obligation	**3,551**	**3,392**	**3,442**	**3,580**	**3,661**	**3,977**	**3,986**	**3,888**	**3,913**	**3,914**
West Reserve Margin	-54%	-51%	-51%	-45%	-44%	-46%	-49%	-38%	-32%	-23%
System										
Total Resources	10,006	10,321	10,839	11,436	11,527	11,866	12,559	13,006	13,758	13,977
Obligation	8,705	8,896	8,944	9,291	9,589	9,665	9,745	9,957	9,953	10,049
Planning Reverve Margin (13%)	1,132	1,157	1,163	1,208	1,247	1,256	1,267	1,294	1,294	1,306
Obligation + Reserves	9,837	10,053	10,107	10,499	10,835	10,922	11,012	11,252	11,247	11,355
System Position	170	268	732	936	691	945	1,547	1,755	2,511	2,622
Reserve Margin	**15%**	**16%**	**21%**	**23%**	**20%**	**23%**	**29%**	**31%**	**38%**	**39%**

Table 6.5 (Cont.) - 2023 IRP Update Winter Capacity Load and Resource Balance (Megawatts)

East	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	6,264	6,264	6,264	4,815	4,117	4,117	2,854	2,854	2,854
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	36	36	36	36	36	36	36	36	36
Wind	552	552	552	552	552	552	552	470	470
Solar	385	383	380	357	354	352	350	347	345
Other Renewable	34	34	34	34	8	8	8	8	8
Storage	467	467	467	467	467	467	467	467	467
Purchase	172	172	172	172	172	172	172	172	172
Qualifying Facilities	259	257	254	213	212	207	206	205	204
Sale	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,169**	**8,165**	**8,159**	**6,645**	**5,918**	**5,911**	**4,645**	**4,560**	**4,556**
Market Purchases	0	0	0	0	0	0	0	0	0
Peaker	584	584	584	640	1,429	1,429	4,385	5,092	5,092
Wind	737	737	737	782	782	782	782	782	738
Solar	303	303	303	540	540	540	540	540	554
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	698	698	709	1,556	1,556	1,556	1,556	1,556	1,556
Nuclear	475	475	475	475	475	475	475	475	475
East Planned Resources	**2,797**	**2,797**	**2,808**	**3,993**	**4,782**	**4,782**	**7,738**	**8,445**	**8,414**
East Total Resources	**10,966**	**10,962**	**10,967**	**10,638**	**10,700**	**10,693**	**12,383**	**13,005**	**12,971**
Load	7,329	7,518	7,607	7,745	7,870	8,007	8,186	8,326	8,472
Private Generation	(19)	(21)	(23)	(25)	(28)	(30)	(32)	(0)	(36)
Existing - Demand Response	(462)	(462)	(462)	(462)	(462)	(462)	(462)	(462)	(462)
New Demand Response	(109)	(114)	(120)	(143)	(210)	(210)	(231)	(270)	(270)
New Energy Efficiency	(1,024)	(1,147)	(1,263)	(1,464)	(1,573)	(1,658)	(1,743)	(1,868)	(2,048)
East Total obligation	**5,715**	**5,774**	**5,738**	**5,651**	**5,598**	**5,648**	**5,719**	**5,726**	**5,655**
East Reserve Margin	92%	90%	91%	88%	91%	89%	117%	127%	129%
West									
Thermal	736	736	736	499	499	499	499	499	499
Peaker	0	0	0	0	0	0	0	0	0
Hydroelectric	554	554	554	554	554	554	554	554	565
Storage	0	0	0	0	0	0	0	0	0
Renewable	0	0	0	0	0	0	0	0	0
Purchase	1	1	1	1	1	1	1	1	1
Qualifying Facilities	120	120	119	105	104	103	103	103	103
Sale	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
West Existing Resources	**1,399**	**1,399**	**1,399**	**1,147**	**1,147**	**1,146**	**1,146**	**1,145**	**1,157**
Market Purchases	0	0	0	0	0	0	0	0	0
Peaker	0	0	0	0	0	0	0	0	0
Wind	617	617	653	808	808	808	808	808	789
Solar	48	48	48	48	48	48	48	48	48
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	847	847	975	1,701	1,701	1,701	1,724	1,732	1,732
Nuclear	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,512**	**1,512**	**1,677**	**2,557**	**2,557**	**2,557**	**2,581**	**2,588**	**2,570**
West Total Resources	**2,911**	**2,911**	**3,076**	**3,705**	**3,704**	**3,703**	**3,726**	**3,734**	**3,726**
Load	4,770	4,917	4,986	4,938	5,058	5,133	5,273	5,285	5,394
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)
New Demand Response	(197)	(198)	(199)	(208)	(225)	(225)	(244)	(249)	(250)
New Energy Efficiency	(588)	(634)	(678)	(720)	(755)	(801)	(844)	(838)	(943)
West Total obligation	**3,975**	**4,074**	**4,098**	**4,000**	**4,068**	**4,096**	**4,174**	**4,187**	**4,190**
West Reserve Margin	-27%	-29%	-25%	-7%	-9%	-10%	-11%	-11%	-11%
System									
Total Resources	13,877	13,873	14,043	14,342	14,404	14,396	16,110	16,739	16,697
Obligation	9,690	9,847	9,836	9,651	9,666	9,744	9,893	9,913	9,846
Planning Reverve Margin (13%)	1,260	1,280	1,279	1,255	1,257	1,267	1,286	1,289	1,280
Obligation + Reserves	10,950	11,128	11,115	10,905	10,922	11,010	11,179	11,202	11,126
System Position	2,928	2,745	2,928	3,437	3,482	3,386	4,931	5,537	5,572
Reserve Margin	**43%**	**41%**	**43%**	**49%**	**49%**	**48%**	**63%**	**69%**	**70%**

Carbon Dioxide Emissions

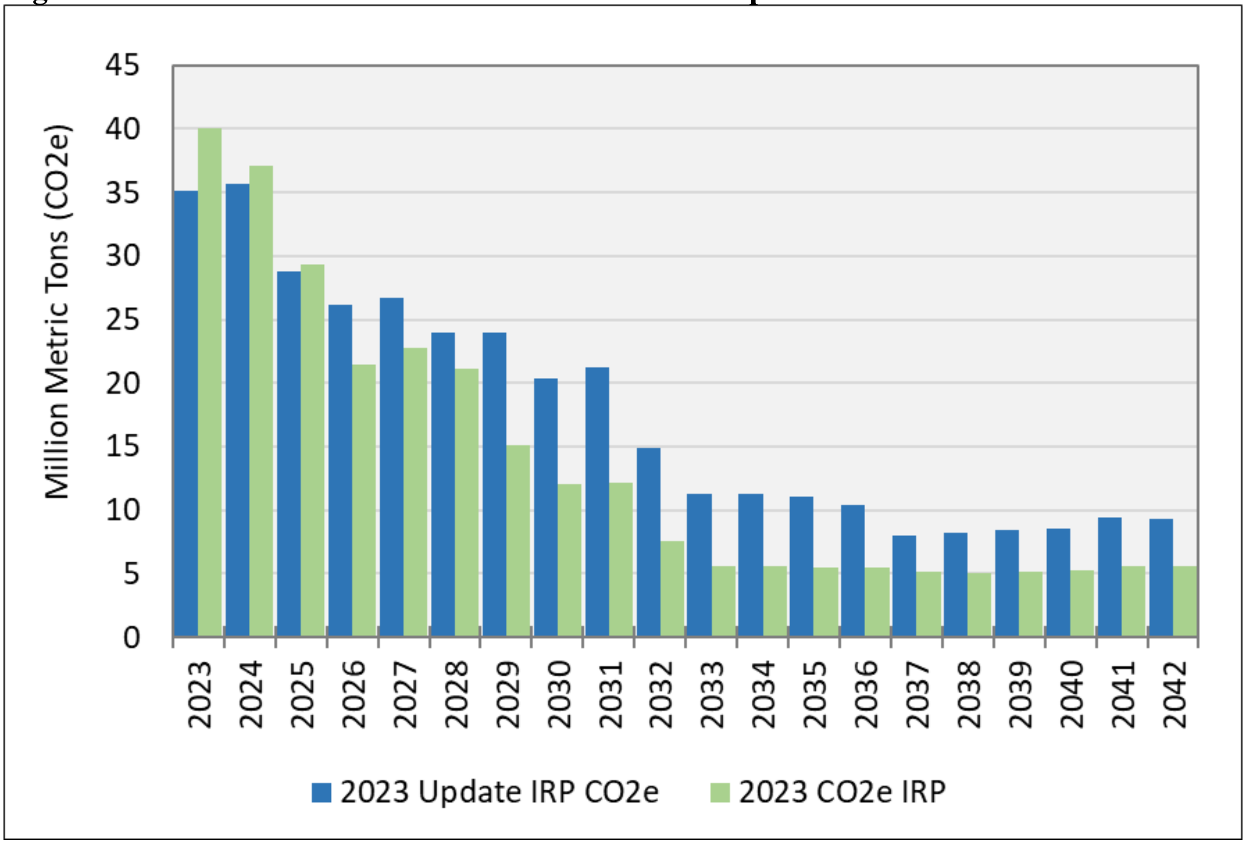
The 2023 IRP Update preferred portfolio reflects PacifiCorp's on-going efforts to provide valuable energy solutions for our customers that reflects a continued trajectory of declining carbon dioxide (CO_2) and other carbon dioxide equivalent (CO_2e) emissions resulting in a measure of total emissions.

PacifiCorp's emissions have been declining and continue to decline related to several factors including PacifiCorp's participation in the EIM and commitment to CAISO's Extended Day-Ahead Market (EDAM), which reduces customer costs and maximizes use of non-emitting renewable resources that have no fuel cost and that generate tax credits.

The chart below in Figure 6.16 compares projected annual CO_2e emissions between the 2023 IRP Update and 2023 IRP preferred portfolios. In this graph, emissions are assigned to market purchases at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour.

In the 2023 IRP Update, emissions are higher than projected in the 2023 IRP starting in 2026. Removal of the OTR, which limited summer generation from gas and coal-fueled resources, is a significant driver. Further, over the longer-term the load forecast in the 2023 IRP Update is higher than in the 2023 IRP. Importantly, the 2023 IRP Update preferred portfolio continues to show a continued downward trajectory in emissions over time. By 2030, average annual CO_2e emissions in the 2023 IRP Update preferred portfolio are reduced by 63% against the year 2005 baseline versus a reduction of 78% against the baseline in the 2023 IRP preferred portfolio. By the end of the planning horizon, system CO_2e emissions are projected to fall from 35.1 million metric tons in 2023 to 9.3 million tons in 2042—a reduction of 73.5%.

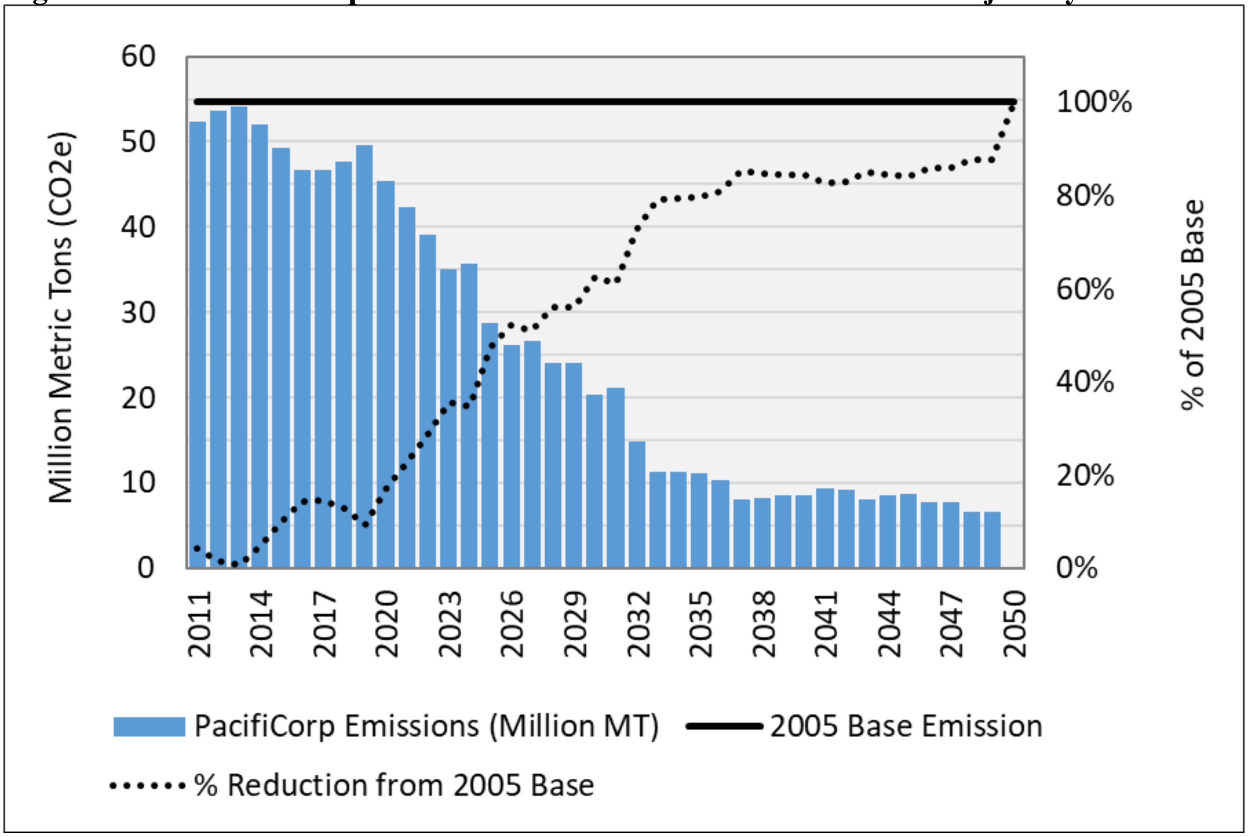
Figure 6.16 –Preferred Portfolio CO2e Emissions Comparison*



* 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 Update 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/megawatt-hour). Emissions from sales are not removed. Beyond 2042, emissions reflect the rolling average emissions of each resource from the 2023 IRP update preferred portfolio through the life of the resource.

Figure 6.17 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour 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_2e emissions are down 47% in 2025, 63% in 2030, 80% in 2035, 84% in 2040, 84% in 2045, and 100% in 2050 (assuming that by 2050, new gas-fired resources added in the preferred portfolio are fueled with a non-emitting fuel alternative.

Figure 6.17 – 2023 IRP Update Preferred Portfolio CO2e Emissions Trajectory*



* The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories.

Oregon and Washington Emissions Compliance

The 2023 IRP Update addresses modeled policy outcomes for Oregon's Clean Energy Plan and the Washington Clean Energy Implementation Plan. Circumstances contributing to emissions with these two legislative actions have changed since the 2023 IRP. To the extent systemwide planning drivers have reduced the overall pressure toward renewables procurement and emissions reductions, this places upward pressure on the magnitude and cost of activity that will be required for both Oregon and Washington compliance.

For example, EPA's approval of Wyoming's OTR plan and the stay of EPA's disapproval of Utah's OTR plan means that federally mandated compliance obligations which drove renewable resource procurement via restrictions on NOx emissions from coal and gas-fired units that were included in the 2023 IRP are now lessened. Consequently, additional renewables are indicated for Oregon and Washington portfolios compared to what has been most recently presented in PacifiCorp's CEP and CEIP biennial reports, respectively. Where federal law dictates compliance action that is aligned with Oregon and Washington legislative goals, the costs and benefits are shared among all customers. However, where state legislation specifically drives alternative procurements, the costs and benefits of those procurements will fall to the individual states and their customers. The process of integrating state level requirements into the preferred portfolio is discussed at length in preceding sections.

At this time, PacifiCorp continues to anticipate that allocations and the multistate process will play a significant role in achieving final compliance with Oregon HB 2021 and Washington CETA requirements.

Renewable Portfolio Standards

Figure 6.18 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the 2023 IRP Update 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.

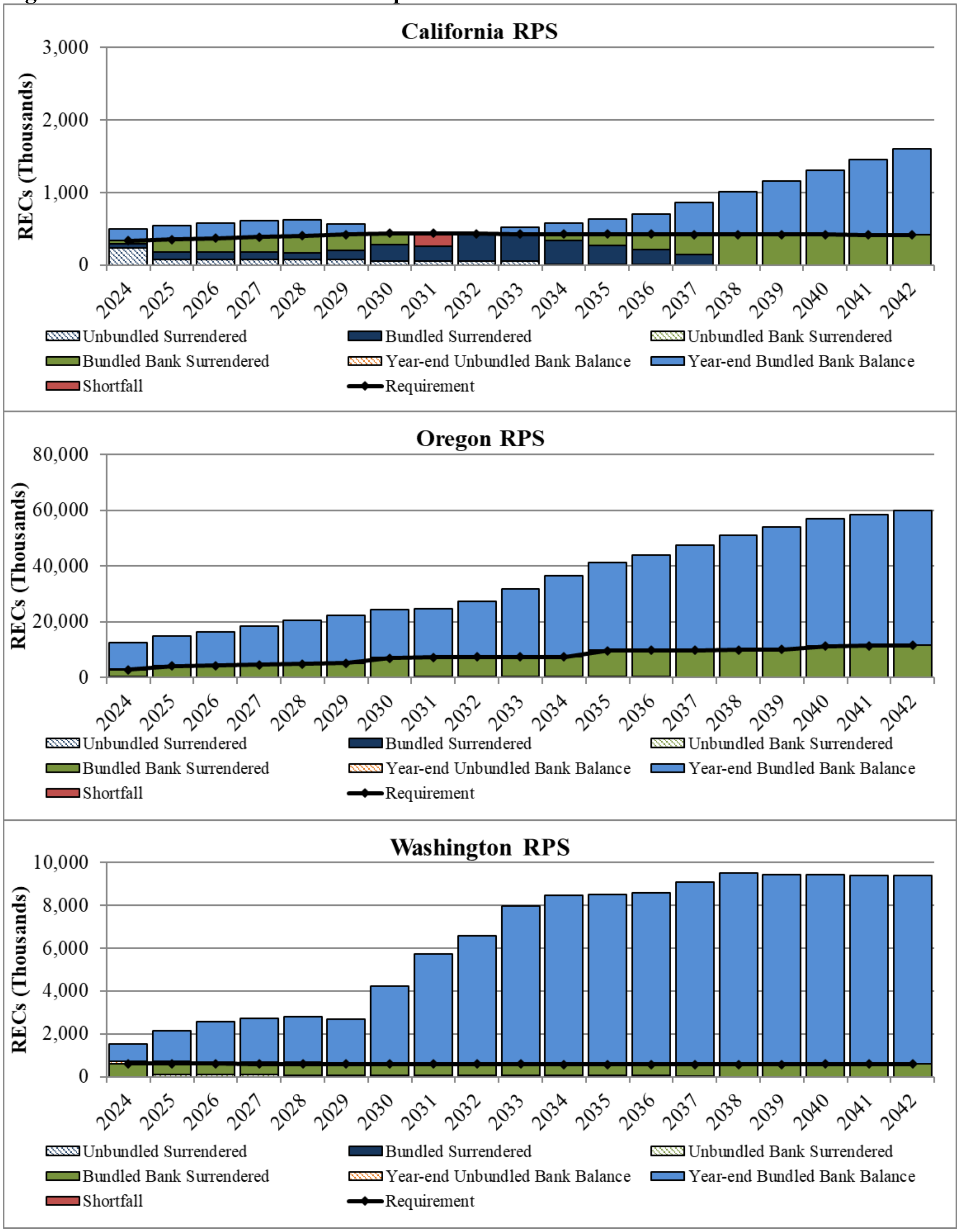
The California RPS compliance position will be met through year 2030 with owned and contracted renewable resources, as well as REC purchases. Beyond 2030, the company may need to purchase approximately ~175,000 RECs per year to meet the RPS target of 60% in years where a shortfall is projected.

Oregon RPS compliance is achieved through 2042 with the addition of new renewable resources in the 2023 IRP Update preferred portfolio.

Under PacifiCorp's 2020 Protocol and the Washington Interjurisdictional Allocation Methodology, Washington's RPS position is improved by receiving a system share of renewable resources across PacifiCorp's system, and there are no anticipated shortfalls.

While not shown in Figure 6.18, PacifiCorp meets the Utah 2025 state target to supply 20% of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources.

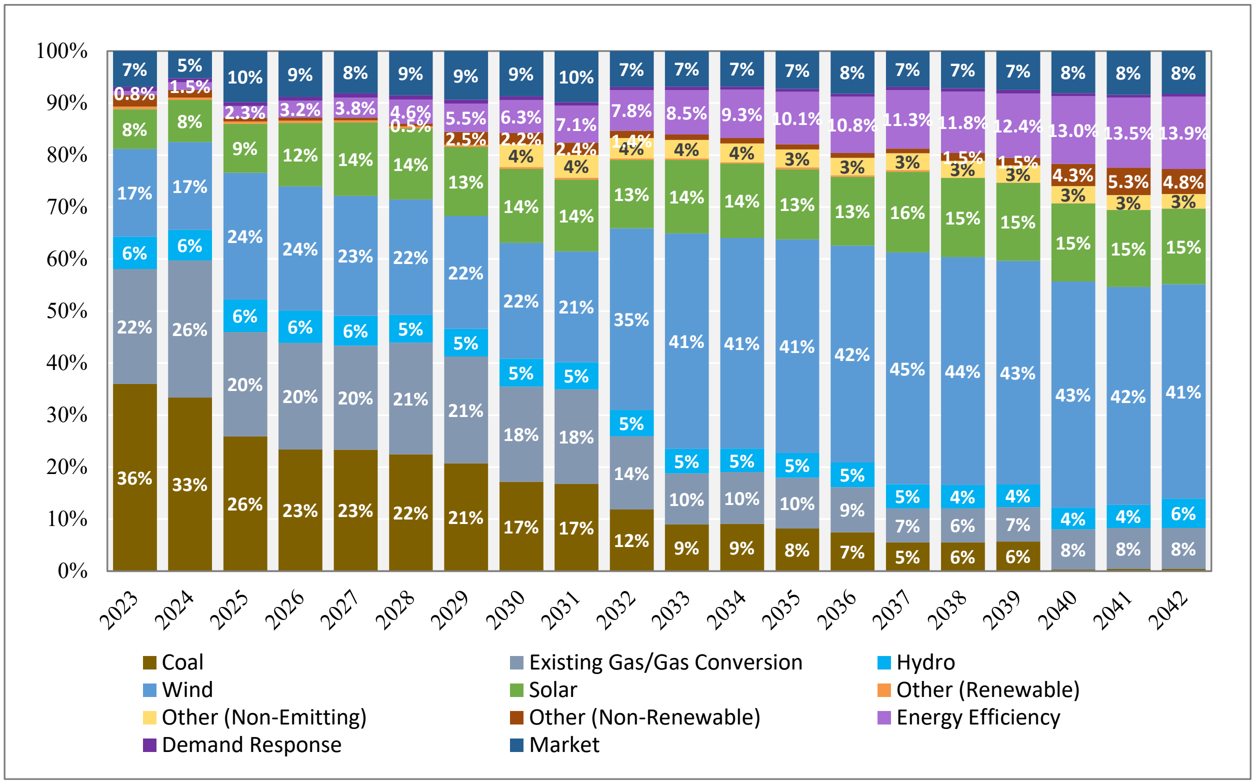
Figure 6.18 – Annual State RPS Compliance Forecast



Projected Energy Mix

Figure 6.19 reports projected changes to PacifiCorp's system energy mix over time, based upon preferred portfolio outcomes in the short-term (ST) model.[2] On an energy basis, coal generation drops to 22% by 2028, falls to 12% by 2032, and declines to less than 1% by year 2040. Reduced energy from coal is offset primarily by increased energy from renewable resources, nuclear resources, DSM, and to a smaller extent later in the plan, peaking resources.

Figure 6.19 – Projected Energy Mix with Preferred Portfolio Resources*

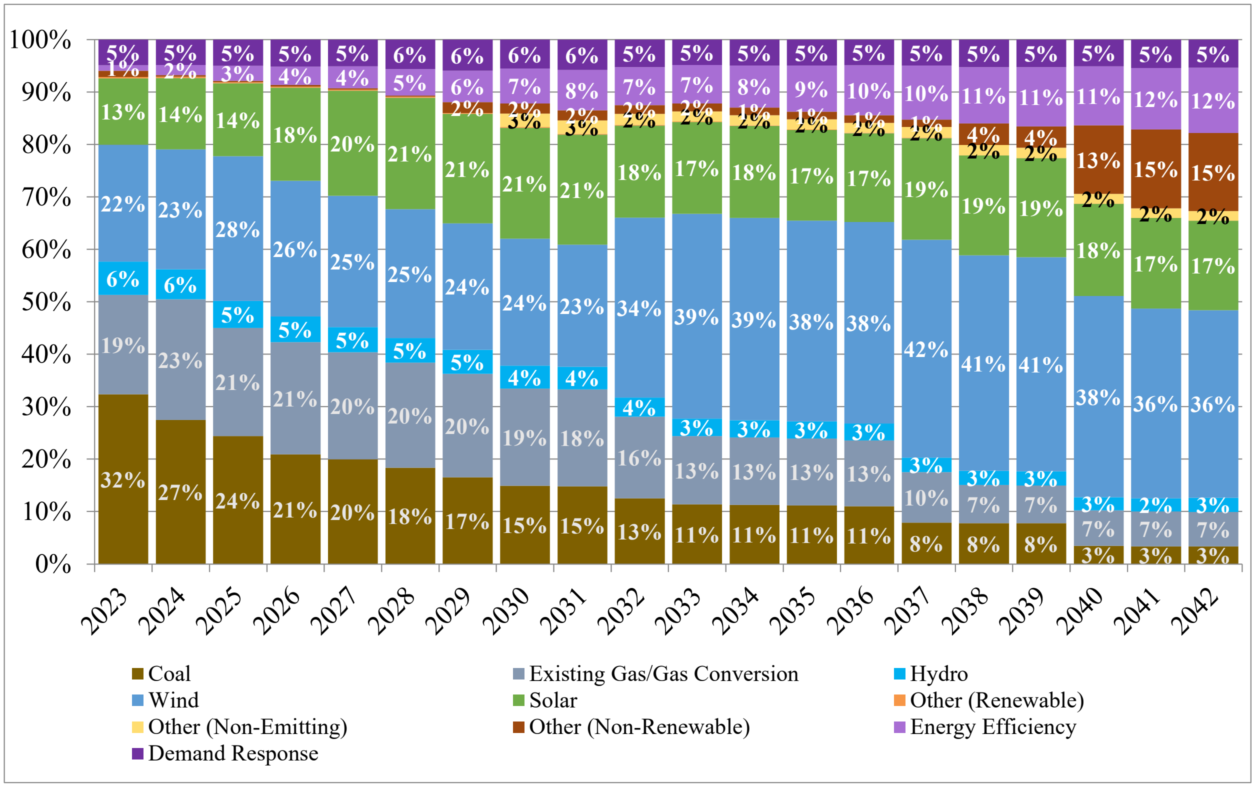


* Storage resources are excluded as they do not provide net energy.

Figure 6.20 shows how PacifiCorp's capacity mix is expected to change over time. Coal capacity drops to 18% of the system in 2028, then further to 11% of the system starting in 2033, and finally to 3% of capacity in 2040. Coal capacity is primarily replaced by renewables that increase in contribution over time. Towards the end of the study period, "other (Non-Renewable)" (mostly new peaking) capacity begins to contribute a larger percentage of system capacity.

[2]The projected PacifiCorp 2023 IRP update 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 solar, wind, biomass, biogas, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future 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 2023 IRP update preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 6.20 – Projected Capacity Mix with 2023 IRP Update Preferred Portfolio Resources*



* Storage resources are excluded as they do not provide net capacity.

Additional Studies

In addition to the 2023 IRP Update preferred portfolio, PacifiCorp developed key variants of the updated preferred portfolio, focusing on critical decision variables addressing significant areas of interest and change. The economics of these studies further supports their value in the 2023 IRP Update preferred portfolio as the least-cost, least-risk portfolio. In addition, PacifiCorp is including the Oregon and Washington standalone Compliance studies within this section to provide clarity about the decisions made for the whole system in order to comply with Oregon or Washington.

The variant portfolios are summarized in Table 6.6. Like the preferred portfolio, all variant studies were taken through the iterative modeling process described earlier in this chapter. Each variant was subject to granularity adjustments and reliability load additions files specific to the portfolio selected by the model for the variant conditions. For the No-Nuclear and all Jim Bridger 3 & 4 variants, the same process was undertaken to incorporate changes to the preferred portfolio as was completed to integrate Oregon and Washington compliance. Because the overall change in these portfolios is not a wholesale baseline change of assumptions, but merely an "in vs. out" (nuclear) or "configuration vs. configuration" study this process was deemed appropriate. For the Offshore Wind and Utah participation in OTR starting in 2027 studies, the base of the model is very different, resulting in changes to the portfolio that were not incorporated into the preferred portfolio, but left to stand alone.

Table 6.6 – Variant Portfolios

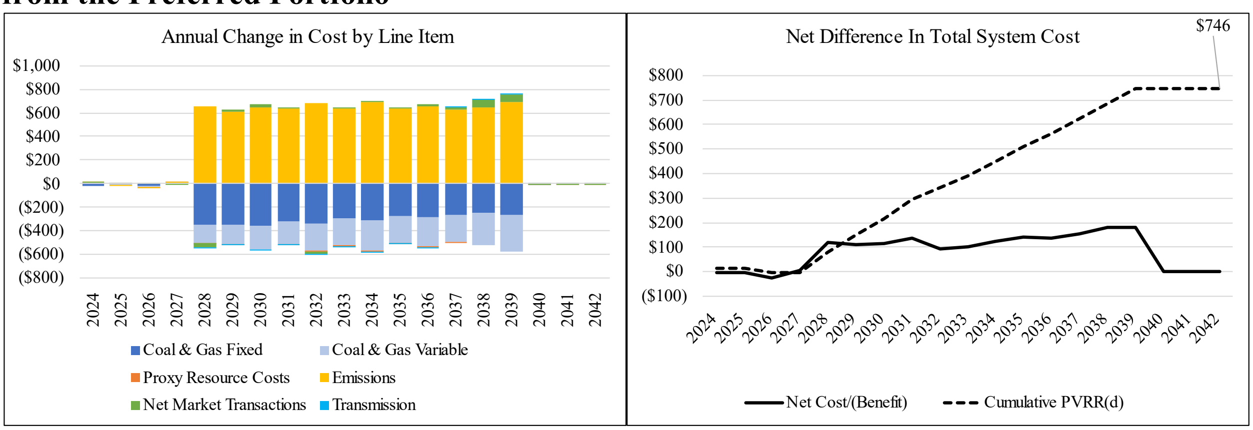
Case	Description
No CCUS	Counterfactual to Preferred Portfolio where Jim Bridger 3 and 4 run as coal
Bridger 3&4 Gas Convert	Counterfactual to Preferred Portfolio where Jim Bridger 3 and 4 convert to gas in 2030
No Nuclear	Counterfactual to Preferred Portfolio where Natrium project is not allowed
Utah OTR Participation	Study to evaluate portfolio selections if Utah OTR Stay order is overturned
Offshore Wind	Study to evaluate portfolio if 1 gigawatt of offshore wind is required in Oregon
Oregon HB 2021	Study to evaluate impact to the entire system if Oregon policy needs were shared
Washington CETA	Study to evaluate impact to the entire system if Washington policy needs were shared

CCUS Variant (No CCUS)

The preferred portfolio selected Jim Bridger 3 and 4 to be converted to CCUS in 2028. Using the methodology described earlier in the chapter, the replacement for the CCUS was selected based on iterative model runs which remove the selection of CCUS. No other resources changes were selected in the absence of CCUS at Jim Bridger units 3 and 4. However, without CCUS these units retire two years earlier, as their operational life is not extended to capture additional ITC benefits.

Figure 6.21 below shows the change in system cost when CCUS at Jim Bridger is not installed, and Jim Bridger 3 and 4 operate as coal through 2037, resulting in a PVRR increase of $746m. This increase is almost entirely driven by the loss of tax credits associated with the CCUS unit. The increase in emissions cost is partially offset by lower fixed and variable costs on the gas converted units, but the loss of the tax credits far outweighs these savings.

Figure 6.21 – Increase/(Decrease) in System Costs when CCUS is Removed from the Preferred Portfolio

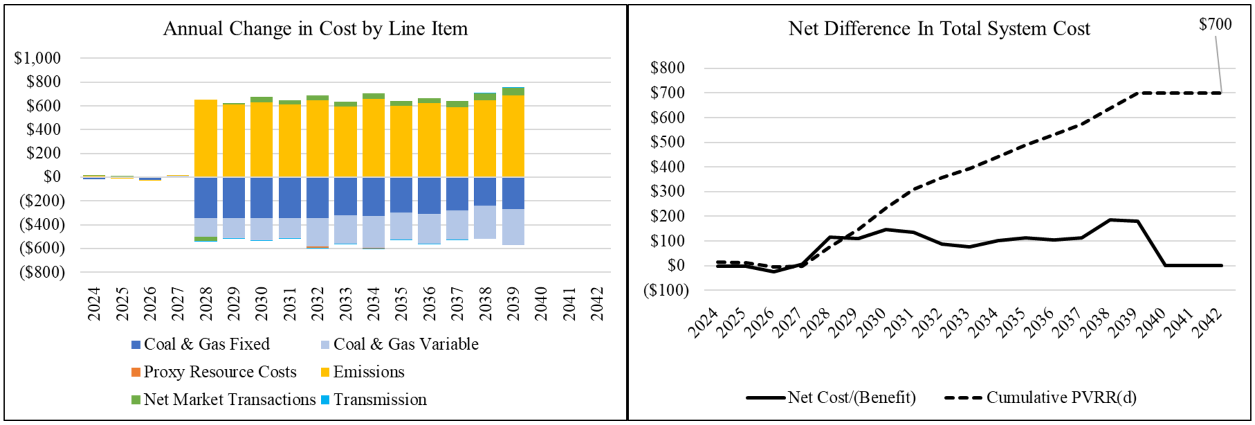


Jim Bridger 3 and 4 Gas Conversion Variant

The preferred portfolio selected Jim Bridger 3 and 4 to be converted to CCUS in 2028. Using the methodology described earlier in the chapter, evaluating Jim Bridger 3 and 4 as gas converted in 2030 was based on the iterative Jim Bridger 3&4 Gas Convert runs. Because no change to other resources at the Jim Bridger area were indicated by that run, the only change to this model was the switch of Jim Bridger from CCUS to gas convert in 2030 and run through 2037, while the CCUS unit retires at year end 2039.

Figure 6.22 below shows the change in system cost when CCUS at Jim Bridger is replaced with a gas conversion of the unit in 2030, resulting in a PVRR increase of $700m. This increase is almost entirely driven by the loss of tax credits associated with the CCUS unit. The increase in emissions cost is partially offset by lower fixed and variable costs on the gas converted units, but the loss of the tax credits far outweighs these savings.

Figure 6.22 – Increase/(Decrease) in System Cost Assuming Jim Bridger 3 and 4 Gas Conversion



Nuclear Variant (No Nuclear)

The preferred portfolio included the Natrium demonstration project at Naughton. Using the methodology described earlier in the chapter, evaluating replacement options for the Natrium Demonstration project was completed using the iterative No Nuclear runs. In those views, gas peaking units replaced the nuclear capacity at Naughton. As a result, this change was incorporated as the replacement for the Natrium demonstration project.

Figure 6.23 – Increase/(Decrease) in Proxy Resources when the Natrium™ Demonstration Project is Removed

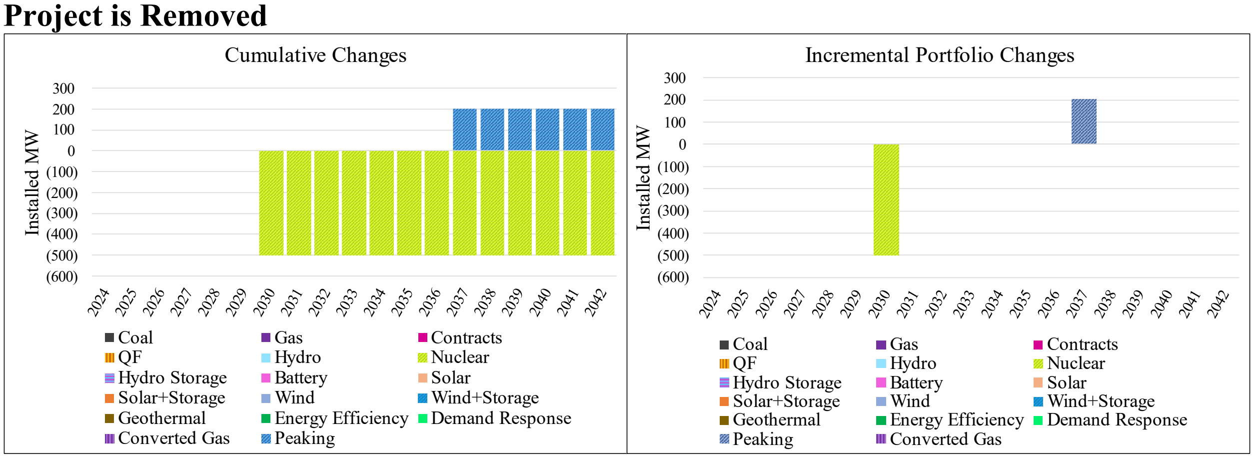
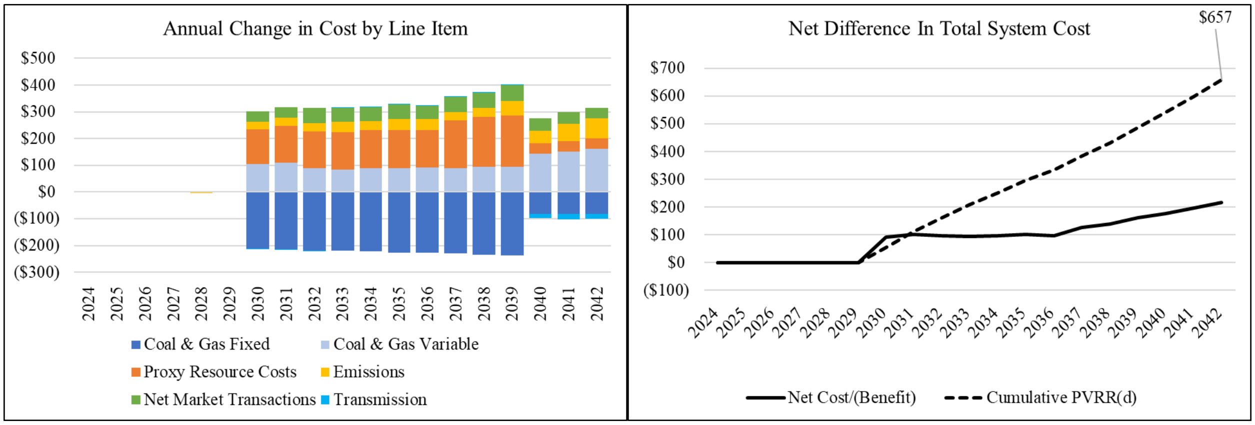


Figure 6.24 below shows the change in system cost when the Natrium project is removed and replaced with a peaking unit in 2037, resulting in a $657m dollar increase in the PVRR of the portfolio. In 2030 when the Natrium plant is removed from the portfolio, proxy resource costs begin to increase as new resources added to the portfolio before 2030 begin to operate differently. Coal and gas variable costs and corresponding emissions costs also increase as the system relies more heavily on those resources for reliability.

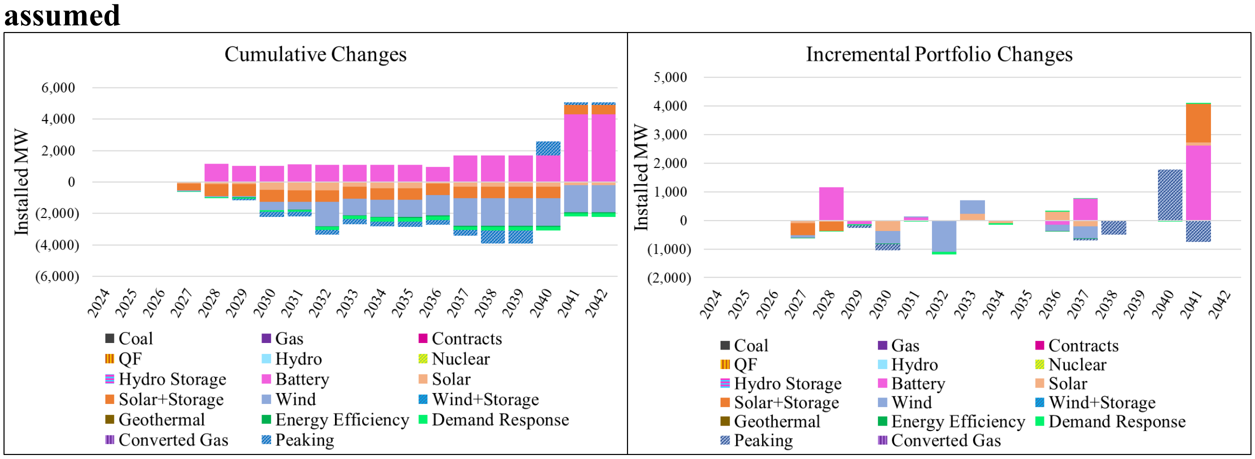
Figure 6.24 – Increase/(Decrease) in System Costs when Nuclear is Removed from the Preferred Portfolio



Utah Stay OTR Variant

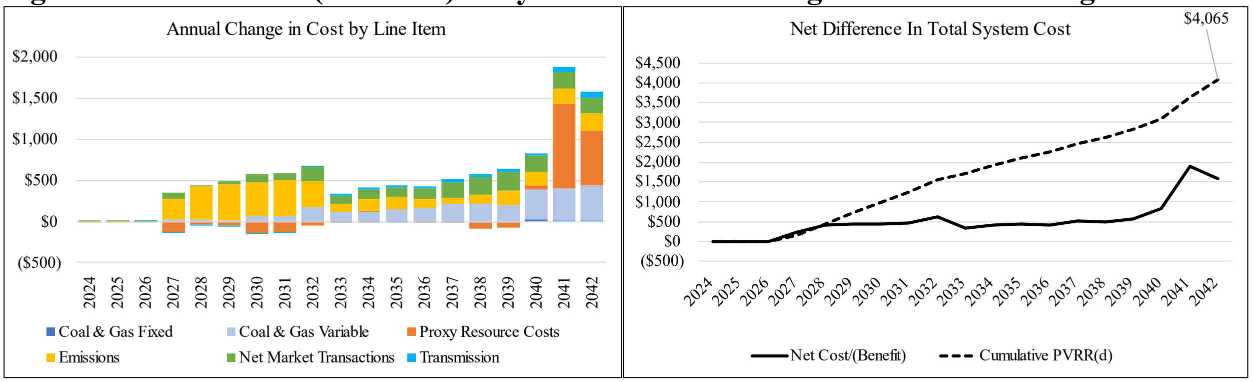
This variant allowed the model to select any portfolio of resources with the assumption that Utah would be subject to an OTR constraint starting in 2027. The significant reduction in the ability for coal units to operate led to a much larger selection of battery storage resources. Additionally, the portfolio relies more heavily on gas production than the preferred portfolio.

Figure 6.25 – Increase/(Decrease) in Proxy Resources when Utah OTR starting in 2027 is assumed



As seen below in Figure 6.26, the addition of the Utah OTR starting in 2027 assumption increases costs to the system by $4.1b. This higher cost is attributed mostly to higher emission costs in the years 2027 through 2032, and proxy resource costs in 2041 and 2042.

Figure 6.26 – Increase/(Decrease) in System Costs Assuming Utah OTR Starting 2027



Oregon Offshore Wind Variant

As seen below in Figure 6.27, the requirement for the model to build offshore wind in 2032 off the coast of southern Oregon results in large changes to the portfolio. Additional battery is selected early while Oregon and Washington situs resources and the early cluster resources are not selected. Because of the differing capacity factor of offshore wind, less overall onshore wind and solar are selected.

Figure 6.27 – Increase/(Decrease) in Proxy Resources Assuming Oregon Offshore Wind is Selected

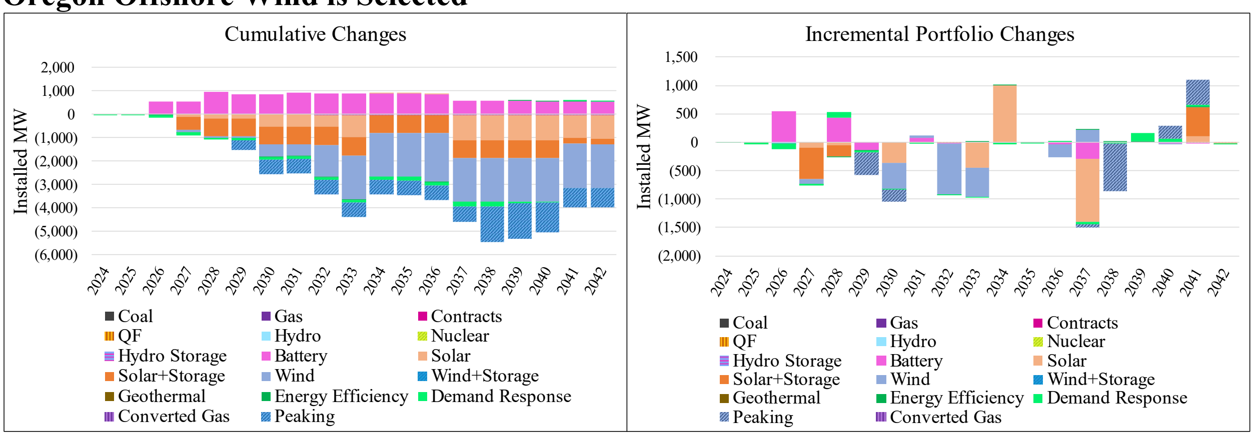
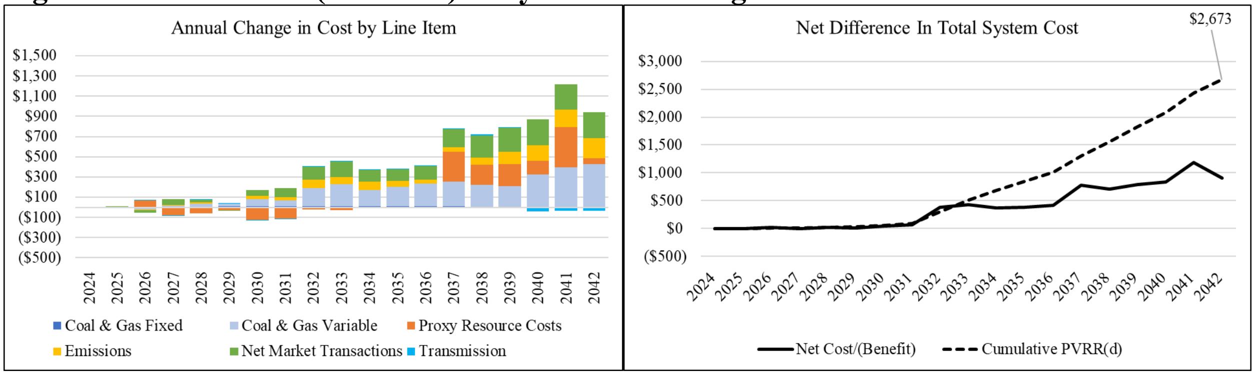


Figure 6.28 below shows the change in system cost with the Oregon offshore wind, resulting in a $2.67b dollar increase in the PVRR of the portfolio. Overall, the change is negligible until 2031, where the system relies more on coal and gas, and has an increase in emissions costs and market transaction costs. Additionally higher proxy resource costs play a role in the higher overall cost of the portfolio.

Figure 6.28 – Increase/(Decrease) in System Cost Oregon Offshore Wind is Selected



Oregon HB 2021 Variant (Oregon Policy Study)

Modeling the Oregon small scale renewable resource requirement and a target to meet Oregon emissions requirements results in large changes to the selected resource mixture. The below portfolio assumes the entire system shares in incremental resources required to meet Oregon compliance (with the exception of small scale renewables). Note that the preferred portfolio (against which the Oregon view is being compared) incorporates Oregon selections, so this comparison shows what would incrementally be added for the other five states within PacifiCorp's footprint under the Oregon view.

In 2029, the portfolio incorporating these requirements adds additional battery. Total wind selections are lower through 2033 but increase starting in 2034. Overall solar selections are lower through the entirety of the period. Total peaking selections are lower overall, with the largest single year difference in 2040.

Figure 6.29 – Increase/(Decrease) in Proxy Resources Assuming Oregon HB 2021 Requirements (Oregon Policy Study)

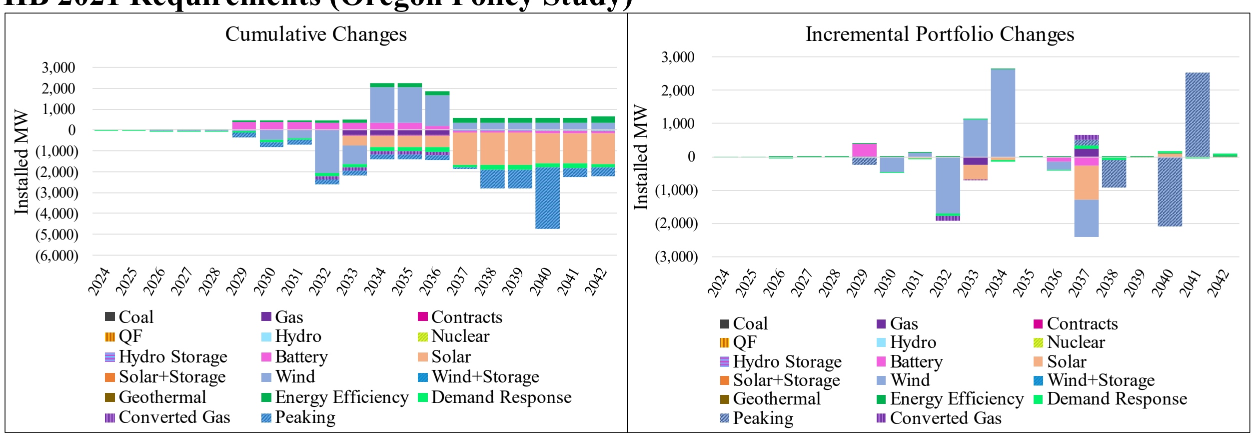
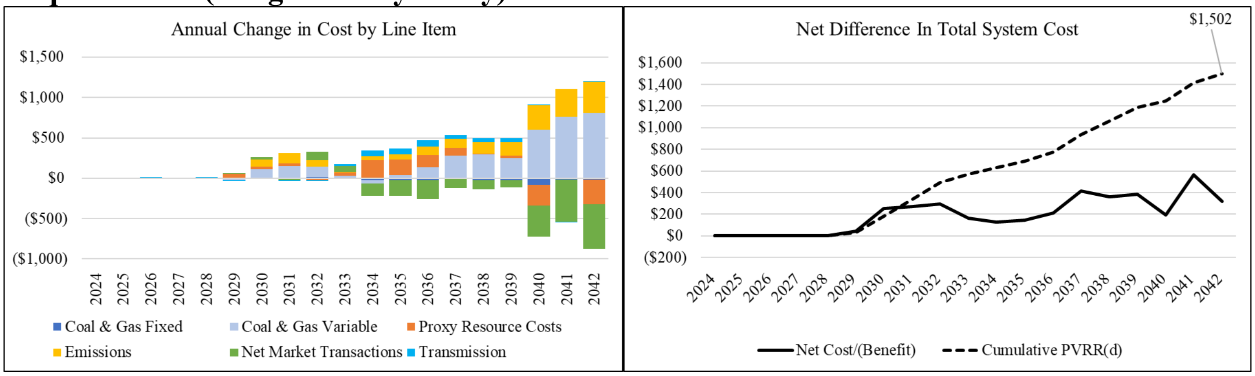


Figure 6.30 below shows the change in system cost when Oregon's requirements are embedded into the system run. The $1.5b PVRR difference is driven by higher proxy resource costs, as well as costs related to the operation of units that Oregon no longer participates in. Overall system level emissions are also higher due to a reliance on coal units in which Oregon no longer participates.

Figure 6.30 – Increase/(Decrease) in System Cost Assuming Oregon HB 2021 Requirements (Oregon Policy Study)



Washington SC CETA Variant (Washington Policy Study)

Modeling the Washington CETA requirements results in large changes to the selected resource mixture. The below portfolio assumes the entire system shares in incremental resources required to meet Washington compliance under SC-GHG. Note that the preferred portfolio (against which the Washington view is being compared) incorporates Washington situs selections, so this comparison shows what would incrementally be added for the other five states within PacifiCorp's footprint under the Washington view.

If the system were to take a larger share of Washington resources, additional wind and battery storage would make up the bulk of the change. The CETA run adds less peaking capacity starting in 2029, and more solar and battery in 2032. Incrementally more battery is added in 2036 and 2037, coupled with less peaking in the last five years of the study. Overall solar selections are approximately flat.

Figure 6.31 – Increase/(Decrease) in Proxy Resources Assuming Washington SC CETA Requirements (Washington Policy Study)

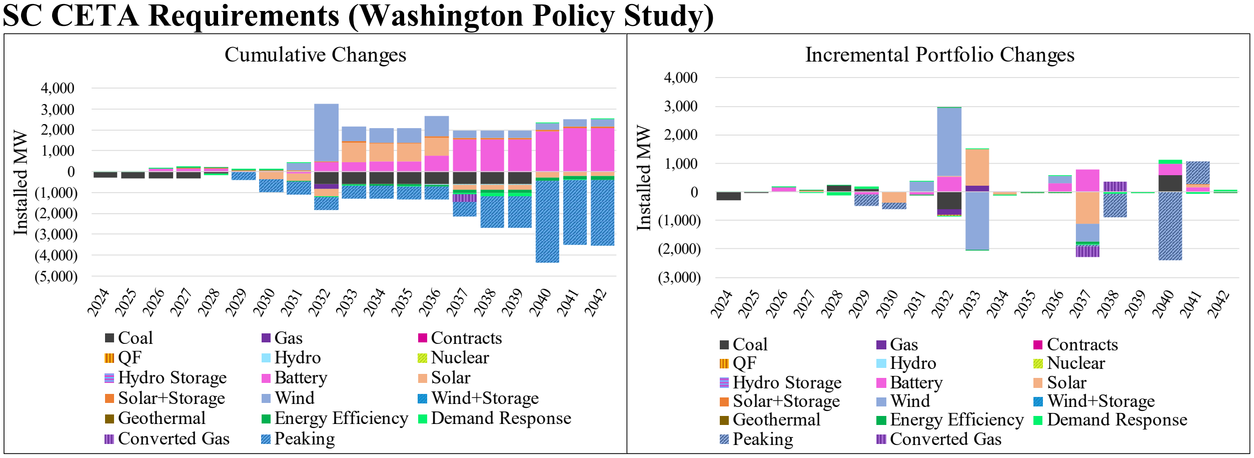
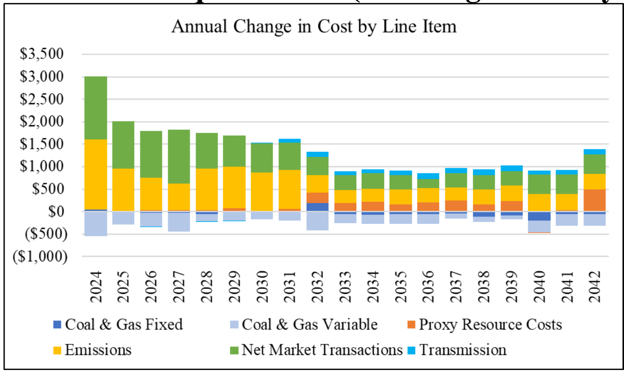
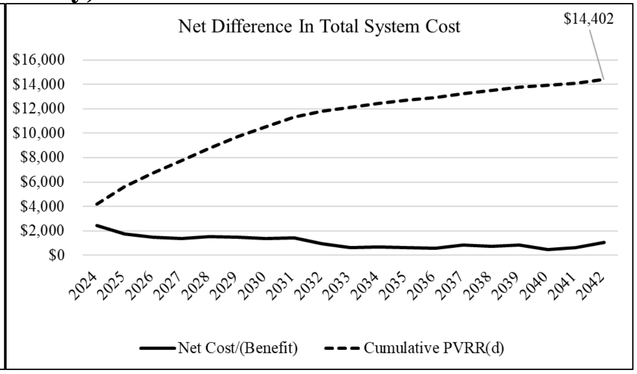


Figure 6.32 shows the change in system cost when the system as a whole is operated under the Washington CETA conditions. The $14.4b PVRR increase in cost is driven primarily by increased

emissions costs due to the SC-GHG emissions cost adder, as well as a significant overall net increase in market costs. Small reductions in coal and gas variable costs offset some of these expenses. Proxy resource costs are higher starting in 2029 and remain higher through the 20 year study period.

Figure 6.32 – Increase/(Decrease) in System Cost Assuming Washington SC CETA Requirements (Washington Policy Study)





PVRR Tables by Price-Policy Scenario

Table 6.7 – Cases Under MN

Period	Case Under MN	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	MN Base	$ 29,519	$ 748	N	N	Y	MN
20-YEAR	Preferred Portfolio	$ 28,823	$ 52	Y	Y	Y	MN
20-YEAR	Systemwide	**$ 28,771**	$ -	N	N	Y	MN
20-YEAR	No CCUS	$ 29,245	$ 474	Y	Y	N	MN
20-YEAR	No Nuclear	$ 29,252	$ 480	Y	Y	Y	MN
20-YEAR	Bridger 3 & 4 GC	$ 29,321	$ 550	Y	N	Y	MN

Table 6.8 – Cases Under MM

Period	Case Under MM	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	MM Base	$ 33,510	$ 703	N	N	Y	MM
20-YEAR	Preferred Portfolio	**$ 32,807**	$ -	Y	Y	Y	MM
20-YEAR	Systemwide	$ 32,912	$ 105	N	N	Y	MM
20-YEAR	No CCUS	$ 33,553	$ 746	Y	Y	N	MM
20-YEAR	No Nuclear	$ 33,464	$ 657	Y	Y	Y	MM
20-YEAR	Bridger 3 & 4 GC	$ 33,506	$ 700	Y	N	Y	MM

Table 6.9 – Cases Under SC-GHG

Period	Case Under SC-GHG	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	SC Base	$ 47,504	$ 350	N	N	Y	SC
20-YEAR	Preferred Portfolio	**$ 47,153**	$ -	Y	Y	Y	SC
20-YEAR	Systemwide	$ 47,730	$ 576	N	N	Y	SC
20-YEAR	No CCUS	$ 48,031	$ 877	Y	Y	N	SC
20-YEAR	No Nuclear	$ 48,493	$ 1,340	Y	Y	Y	SC
20-YEAR	Bridger 3 & 4 GC	$ 47,965	$ 812	Y	N	Y	SC

Table 6.10 – Cases Under LN

Period	Case Under LN	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	LN Base	$ 29,241	$ 1,447	N	N	Y	LN
20-YEAR	Preferred Portfolio	$ 28,042	$ 249	Y	Y	Y	LN
20-YEAR	Systemwide	**$ 27,794**	$ -	N	N	Y	LN
20-YEAR	No CCUS	$ 28,441	$ 647	Y	Y	N	LN
20-YEAR	No Nuclear	$ 28,212	$ 418	Y	Y	Y	LN
20-YEAR	Bridger 3 & 4 GC	$ 28,357	$ 563	Y	N	Y	LN

Table 6.11 – Cases Under HH

Period	Case Under HH	PVRR ($000)	Delta ($000)	OR 80% 2030	WA RPS	CCUS	Dispatch Price
20-YEAR	HH Base	**$ 41,622**	$ -	N	N	Y	HH
20-YEAR	Preferred Portfolio	$ 41,658	$ 36	Y	Y	Y	HH
20-YEAR	Systemwide	$ 42,252	$ 630	N	N	Y	HH
20-YEAR	No CCUS	$ 43,005	$ 1,384	Y	Y	N	HH
20-YEAR	No Nuclear	$ 43,047	$ 1,425	Y	Y	Y	HH
20-YEAR	Bridger 3 & 4 GC	$ 43,013	$ 1,392	Y	N	Y	HH

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CHAPTER 7 – ACTION PLAN STATUS UPDATE

This chapter provides an update on the action items listed in the Action Plan of PacifiCorp's 2023 Integrated Resource Plan (IRP). The status for all action items is provided in Table 7.1 below.

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Table 7.1 – 2023 IRP Action Plan Status Update

Action Item	1. Existing Resource Actions	Status
1a	**Colstrip Units 3 and 4:** • PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030.	• PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP Update preferred portfolio target exit date of December 31, 2025.	• PacifiCorp continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1c	**Naughton Units 1 and 2 Gas Conversion:** • 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.	• PacifiCorp is on track to complete required regulatory notices and filings to process the conversion of Naughton Units 1 and 2 from coal to natural gas. • Coal supply agreements for Naughton Units 1 and 2 will not be extended beyond the end of December 2025.
1d	**Jim Bridger Units 1 and 2 Gas Conversion:** • 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.	• PacifiCorp received an approval order on December 7, 2023 from the Wyoming Public Service Commission for the conversion of Jim Bridger Units 1 and 2 from coal to natural gas. • PacifiCorp ceased coal-fueled operations at Jim Bridger Units 1 and 2 on December 31, 2023.

	• By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	• Removal of coal handling equipment and installation of natural gas components began on January 1, 2024. Conversions are on track for completion in Q2 2024.
1e	**Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:** • PacifiCorp will complete an 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.	• PacifiCorp completed its evaluation of information received as part of the CCUS RFP and RFI process in August of 2023. • PacifiCorp filed its final plan with the Wyoming Public Service Commission on March 29, 2024, as required under Wyoming House Bill 200.
1f	**Regional Haze Compliance:** • 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.	• Utah's first planning period disputes have been resolved. • Naughton and Wyodak's first planning period disputes have been resolved. The Tenth Circuit found EPA's disapproval of Wyoming's plan for Wyodak unlawful and remanded the plan to EPA for further review in accordance with the requirements of the Clean Air Act. No proposed rule has been issued to date. • Wyoming submitted its state-approved revised regional haze plan requiring the natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. EPA is reviewing the state plan. PacifiCorp continues to comply with the state-approved plan and operating permits. • PacifiCorp continues to engage with the EPA, state agencies, and stakeholders relating to second planning period regional haze compliance. No

		second planning period requirements have been finalized by EPA to date.
1g	**<u>Natrium™ Demonstration Project:</u>** • PacifiCorp will continue to monitor and report 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. 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.	Unchanged
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-	• EPA finalized its approval of Wyoming's cross-state ozone state plan on December 19, 2023. This approval means PacifiCorp facilities in Wyoming are not subject to the federal ozone plan requirements. • The Tenth Circuit granted a motion to stay EPA's disapproval of Utah's state ozone plan. Utah is not subject to federal ozone requirements while the stay is in place. The Utah ozone case was transferred to the D.C. Circuit in February of 2024, for adjudication of the merits, leaving the stay in place.

	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**	**Status**
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% renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2024 or 2025, which may necessitate issuance of a request for proposals to procure resources within the action plan window.	• PacifiCorp and the eligible communities are meeting monthly to discuss program design. Subject to the finalization of the program details, PacifiCorp anticipates applying for approval of the program with the Utah Public Service Commission in 2024 or 2025.
2b	**2024 All-Source Request for Proposals:** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the	• PacifiCorp does not have plans to issue an all-source Request for Proposals at this time but is continuously receiving and evaluating offers for resources to meet its requirements.

	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.	• Based on the resource procurement need identified in this IRP Update, it is likely that the 2025 IRP will include an action item to procure incremental resources to serve customers over the long term. Nonetheless, a new resource procurement action item will be established after development of the 2025 IRP.
2c	**<u>2022 All-Source Request for Proposals:</u>** • In April 2022 PacifiCorp issued an all-source Request for Proposals to procure resources that can achieve commercial operations by the end of December 2027.	• PacifiCorp suspended the 2022 All-Source RFP in September 2023 to further evaluate how key changes in the planning environment might influence long-term resource procurement activities.

	• 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.	• EPA's approval of Wyoming's cross-state ozone transport rule plan and the Tenth Circuit Court's stay of Utah's ozone plan have materially impacted the need for the type and volume of resources identified in the 2023 IRP preferred portfolio, which considered resource procurement needs coming out of the 2022 All-Source Request for Proposals. • Consequently, PacifiCorp is executing on a near-term resource procurement strategy that is consistent with the preferred portfolio in this IRP Update and will terminate the 2022 All Source Request for Proposals.
Action Item	3. **Transmission Action Items**	**Status**
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.	• Regulatory approval processes for certificates of public convenience and necessity in Utah and Wyoming are on track. In Utah an unopposed stipulation for the CPCN was filed February 22, 2022, and a commission order is pending. In Wyoming, hearings were completed March 2, 2022, and briefs due April 1, 2022; a decision is expected in early Q2 2022. Wyoming approval will be conditioned on obtaining all right-of-way, which is on track to be completed by the end of Q2 2022.

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. •	• PacifiCorp is finalizing construction of the Energy Gateway South and Energy Gateway West Sub-Segment D1 transmission projects.
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 2026-2027 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.	PacifiCorp has continued to participate in the support, negotiations, planning and permitting of the Boardman-to-Hemingway 500 kilovolt transmission line, which remains targeted for a 2026-2027 in-service date.
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	Reinforcements have been identified. A final assessment of upgrades is pending signed agreements.
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 continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment.

	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><th>Status</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>1st Year Energy Efficiency (GWh)</th><th>Annual Capacity (MW)</th></tr>
<tr><td>2023</td><td>543</td><td>123</td></tr>
<tr><td>2024</td><td>559</td><td>220</td></tr>
<tr><td>2025</td><td>568</td><td>259</td></tr>
<tr><td>2026</td><td>628</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.
</td><td>

PacifiCorp achieved the Action Plan target of 543 GWh in 2023 and is on track to achieve its 2024 Class 2 DSM target.
PacifiCorp has launched a number of new demand response programs in 2022 and 2023. Additionally, the company is currently expanding its existing programs. PacifiCorp continues to pursue the incremental capacity additions but did not achieve the 2023 incremental capacity , due to the later than anticipated timing of program effective dates for newly launched demand response programs. However, the company anticipates achieving its cumulative capacity for 2024.

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

	[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 existing resources or as an expansion of existing resources offered through approved programs.	
Action Item	5. **Market Purchases**	**Status**
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.	• Since the publication of the 2023 IRP action plan, PacifiCorp has continued to transact consistent with its risk management and energy supply procedures to reliably cost-effectively serve customer requirements. Such transactions include seeking competitive pricing to acquire short-term firm purchases, execute balance of month, day-ahead and hour-ahead transactions through exchanges, and engage in prompt-month, balance-of-month, day-ahead and hour-ahead non-brokered bi-lateral transactions.

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

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APPENDIX A – ADDITIONAL LOAD FORECAST DETAILS

The load forecast presented in Chapter 4 represents the data used for capacity expansion modeling and excludes load reductions from incremental energy efficiency resources (Class 2 DSM). The load forecast used in the 2023 IRP Update was produced in May 2023. The average annual energy growth rate for the 2024 through 2042 timeframe is 2.13 percent. Relative to the load forecast prepared for the 2023 IRP, PacifiCorp's 2041 forecasted energy requirement decreased in all jurisdictions other than Utah. Table A.1 and Table A.2 illustrate the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures (Class 2 DSM).[1]

Table A.1 – Forecasted Annual Load Growth, 2024 through 2042 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2024	64,968,110	16,245,780	4,585,770	843,490	29,595,760	9,737,710	3,959,600
2025	67,342,930	17,306,840	4,594,200	838,350	30,789,780	9,840,730	3,973,030
2026	68,341,610	18,158,130	4,613,400	837,260	30,853,380	9,882,670	3,996,770
2027	71,581,930	19,426,800	4,629,410	836,940	32,713,240	9,955,510	4,020,030
2028	76,717,850	21,035,020	4,664,190	839,860	36,091,430	10,038,900	4,048,450
2029	78,931,210	22,407,980	4,681,190	838,600	36,875,730	10,065,380	4,062,330
2030	81,000,340	23,159,280	4,710,570	840,340	38,109,540	10,100,330	4,080,280
2031	83,090,030	24,287,060	4,737,420	841,830	38,958,030	10,168,810	4,096,880
2032	84,020,840	24,745,390	4,775,560	844,880	39,308,670	10,229,110	4,117,230
2033	84,868,040	24,957,970	4,792,040	843,400	39,868,630	10,280,680	4,125,320
2034	85,779,130	25,202,840	4,825,440	844,690	40,424,050	10,342,060	4,140,050
2035	86,764,370	25,492,360	4,863,490	846,560	40,999,620	10,406,500	4,155,840
2036	87,968,040	25,852,880	4,918,760	850,950	41,669,790	10,496,540	4,179,120
2037	88,920,970	26,150,610	4,952,290	850,940	42,234,980	10,541,160	4,190,990
2038	90,083,150	26,508,200	5,002,820	853,330	42,896,560	10,611,960	4,210,280
2039	91,291,270	26,881,290	5,055,910	855,790	43,580,400	10,686,960	4,230,920
2040	92,669,760	27,298,340	5,123,440	860,460	44,346,910	10,783,150	4,257,460
2041	93,733,980	27,630,780	5,163,010	860,290	44,980,320	10,829,300	4,270,280
2042	94,980,880	28,011,130	5,218,220	862,720	45,695,500	10,902,990	4,290,320
Compound Annual Growth Rate							
2024-33	3.01%	4.89%	0.49%	0.00%	3.37%	0.60%	0.46%
2024-42	2.13%	3.07%	0.72%	0.13%	2.44%	0.63%	0.45%

[1] Class 2 DSM load reductions are included as resources in the System Optimizer model.

Table A.2 - Forecasted Annual Coincident Peak Load (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2024	11,200	2,645	832	146	5,578	1,240	759
2025	11,576	2,786	840	146	5,736	1,276	792
2026	11,629	2,868	846	148	5,742	1,233	791
2027	12,019	3,020	853	149	5,943	1,263	790
2028	12,528	3,137	860	149	6,362	1,245	774
2029	12,844	3,313	867	150	6,461	1,277	776
2030	13,077	3,403	873	150	6,612	1,260	778
2031	13,491	3,580	883	152	6,766	1,295	815
2032	13,522	3,647	899	156	6,742	1,254	824
2033	13,670	3,675	908	156	6,836	1,287	806
2034	13,807	3,707	918	157	6,924	1,294	807
2035	13,973	3,745	929	158	7,026	1,305	810
2036	14,212	3,791	940	159	7,128	1,315	879
2037	14,444	3,865	957	160	7,287	1,324	849
2038	14,618	3,910	968	161	7,399	1,330	851
2039	14,767	3,956	979	161	7,500	1,338	833
2040	14,930	3,998	989	162	7,598	1,351	833
2041	15,106	4,050	998	162	7,700	1,360	836
2042	15,437	4,202	1,017	165	7,814	1,371	870
Compound Annual Growth Rate							
2024-33	**2.24%**	**3.72%**	**0.98%**	**0.79%**	**2.29%**	**0.42%**	**0.68%**
2024-42	**1.80%**	**2.60%**	**1.12%**	**0.69%**	**1.89%**	**0.56%**	**0.76%**

Table A.3 and Table A.4 show the forecast changes relative to the 2023 IRP load forecast for loads and coincident system peak, respectively.

Table A.3 – Annual Load Growth Change: 2023 IRP Update Forecast less 2023 IRP Forecast (Megawatt-hours) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2024	(2,531,160)	(2,128,670)	(106,340)	(18,070)	(144,270)	(25,850)	(107,960)
2025	(2,462,130)	(2,423,480)	(106,560)	(16,870)	428,560	(234,130)	(109,650)
2026	(1,596,810)	(2,299,520)	(108,360)	(15,710)	1,165,900	(230,570)	(108,550)
2027	(1,067,840)	(2,334,490)	(127,420)	(16,240)	1,678,820	(161,430)	(107,080)
2028	36,730	(2,410,940)	(147,010)	(16,620)	2,907,690	(190,210)	(106,180)
2029	1,011,930	(1,544,800)	(160,120)	(16,560)	3,014,370	(174,590)	(106,370)
2030	2,188,500	(906,780)	(174,780)	(15,450)	3,625,640	(232,220)	(107,910)
2031	2,709,340	(534,630)	(193,280)	(14,770)	3,758,140	(195,310)	(110,810)
2032	2,699,060	(415,490)	(214,840)	(15,080)	3,708,320	(247,620)	(116,230)
2033	2,645,810	(461,810)	(234,210)	(15,300)	3,706,680	(227,590)	(121,960)
2034	2,427,590	(538,750)	(251,540)	(15,430)	3,578,720	(217,420)	(127,990)
2035	2,214,410	(592,800)	(265,300)	(15,330)	3,424,820	(203,540)	(133,440)
2036	1,983,190	(645,890)	(278,160)	(13,920)	3,251,390	(189,950)	(140,280)
2037	1,741,220	(697,660)	(289,600)	(12,540)	3,066,420	(177,980)	(147,420)
2038	1,497,900	(749,210)	(300,050)	(11,340)	2,877,410	(163,610)	(155,300)
2039	1,264,110	(796,550)	(309,440)	(10,240)	2,690,480	(146,310)	(163,830)
2040	1,025,650	(846,980)	(316,480)	(9,310)	2,501,260	(130,110)	(172,730)
2041	737,420	(918,850)	(321,730)	(8,500)	2,283,370	(115,200)	(181,670)
2042	389,750	(1,007,770)	(326,570)	(7,830)	2,019,850	(97,090)	(190,840)

Table A.4 – Annual Coincident Peak Growth Change: 2023 IRP Update Forecast less 2023 IRP Forecast (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2024	(228)	(188)	(14)	(1)	41	(55)	(11)
2025	(171)	(225)	(16)	(1)	108	(25)	(11)
2026	(129)	(186)	(24)	0	170	(72)	(17)
2027	(32)	(168)	(34)	(1)	237	(43)	(23)
2028	43	(186)	(45)	(2)	369	(73)	(20)
2029	161	(174)	(60)	(7)	438	(15)	(22)
2030	261	(104)	(72)	(8)	511	(42)	(24)
2031	369	(50)	(83)	(8)	552	(16)	(26)
2032	313	15	(86)	(5)	473	(61)	(23)
2033	323	5	(98)	(6)	480	(35)	(24)
2034	295	(4)	(109)	(6)	476	(36)	(27)
2035	281	(9)	(115)	(6)	476	(34)	(30)
2036	258	(10)	(125)	(7)	474	(33)	(42)
2037	326	10	(127)	(6)	519	(31)	(39)
2038	318	4	(131)	(6)	523	(31)	(41)
2039	304	(2)	(134)	(7)	515	(30)	(38)
2040	259	(22)	(141)	(8)	498	(28)	(40)
2041	225	(28)	(151)	(9)	482	(27)	(43)
2042	250	16	(150)	(8)	465	(25)	(49)

This section provides total system and state-level forecasted retail sales summaries measured at the customer meter by customer class including load reduction projections from new energy efficiency measures from the 2023 IRP Update preferred portfolio. The average annual retail sales growth rate for the 2024 through 2042 time period is 1.23 percent.

Table A.5 – System Annual Retail Sales Forecast 2024 through 2042 (Megawatt-hours), post-DSM

System Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	17,835,359	22,022,137	18,129,854	1,464,602	101,588	59,553,539
2025	17,942,494	23,278,978	18,467,591	1,459,535	98,916	61,247,513
2026	18,069,292	24,757,523	17,208,712	1,457,137	97,095	61,589,760
2027	18,206,269	27,097,919	17,256,311	1,455,278	95,610	64,111,386
2028	18,404,095	31,140,919	17,280,459	1,454,743	94,532	68,374,747
2029	18,477,357	32,446,403	17,226,100	1,454,103	92,916	69,696,878
2030	18,606,777	33,539,212	17,210,097	1,453,570	91,552	70,901,208
2031	18,675,809	34,617,478	17,240,040	1,452,530	90,221	72,076,078
2032	18,820,591	34,586,724	17,254,846	1,450,538	89,285	72,201,984
2033	18,835,115	34,621,087	17,256,601	1,447,587	88,046	72,248,436
2034	18,996,580	34,605,852	17,235,396	1,445,981	87,309	72,371,118
2035	19,150,780	34,635,808	17,258,048	1,446,071	86,790	72,577,498
2036	19,538,961	34,643,086	17,290,488	1,445,336	86,694	73,004,564
2037	19,799,830	34,611,441	17,243,053	1,441,270	86,217	73,181,811
2038	20,105,118	34,651,180	17,352,250	1,440,699	86,074	73,635,320
2039	20,614,193	34,653,725	17,378,585	1,441,351	85,984	74,173,839
2040	21,076,584	34,765,209	17,459,911	1,440,498	86,178	74,828,378
2041	21,548,567	34,680,463	17,469,255	1,437,205	85,894	75,221,384
2042	22,232,471	34,699,960	17,363,944	1,435,197	85,872	75,817,444
Compound Annual Growth Rate						
2024-33	**0.61%**	**5.16%**	**-0.55%**	**-0.13%**	**-1.58%**	**2.17%**
2024-42	**1.23%**	**2.56%**	**-0.24%**	**-0.11%**	**-0.93%**	**1.35%**

Table A.6– Forecasted Retail Sales Growth in Oregon, post-DSM

Oregon Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	6,009,691	6,770,640	1,423,019	254,060	30,978	14,488,387
2025	6,001,793	7,550,785	1,453,780	254,046	30,286	15,290,690
2026	5,995,405	8,177,475	1,460,958	254,434	29,787	15,918,058
2027	6,003,026	9,161,375	1,473,922	254,806	29,402	16,922,531
2028	6,040,301	10,444,341	1,471,106	255,295	29,196	18,240,240
2029	6,049,448	11,550,309	1,457,111	255,521	28,897	19,341,286
2030	6,090,809	12,048,507	1,458,396	255,858	28,741	19,882,311
2031	6,127,520	12,883,018	1,465,861	256,183	28,628	20,761,210
2032	6,199,100	13,093,944	1,479,500	256,629	28,630	21,057,804
2033	6,237,207	13,137,551	1,466,220	256,811	28,489	21,126,278
2034	6,338,859	13,139,320	1,468,115	257,125	28,448	21,231,867
2035	6,468,636	13,149,739	1,479,593	257,436	28,419	21,383,824
2036	6,669,733	13,154,447	1,502,446	257,906	28,481	21,613,013
2037	6,811,623	13,159,336	1,512,959	258,098	28,384	21,770,399
2038	7,025,020	13,161,006	1,537,519	258,427	28,373	22,010,346
2039	7,234,260	13,182,394	1,561,310	258,757	28,366	22,265,087
2040	7,472,789	13,213,778	1,582,701	259,234	28,443	22,556,946
2041	7,673,642	13,233,651	1,581,848	259,423	28,357	22,776,921
2042	7,903,205	13,247,462	1,596,956	259,761	28,355	23,035,739
Compound Annual Growth Rate						
2024-33	**0.41%**	**7.64%**	**0.33%**	**0.12%**	**-0.93%**	**4.28%**
2024-42	**1.53%**	**3.80%**	**0.64%**	**0.12%**	**-0.49%**	**2.61%**

Table A.7 – Forecasted Retail Sales Growth in Washington, post-DSM

Washington Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	1,601,673	1,506,545	804,037	157,390	3,954	**4,073,599**
2025	1,596,063	1,487,833	790,828	156,906	3,946	**4,035,576**
2026	1,606,514	1,478,251	779,113	155,415	3,946	**4,023,239**
2027	1,599,312	1,472,524	772,203	155,946	3,946	**4,003,931**
2028	1,597,287	1,471,963	767,628	156,535	3,958	**3,997,372**
2029	1,583,980	1,461,843	763,578	157,015	3,946	**3,970,362**
2030	1,574,662	1,455,718	760,964	157,382	3,946	**3,952,672**
2031	1,560,284	1,449,623	758,497	157,457	3,946	**3,929,807**
2032	1,549,350	1,448,952	758,110	157,384	3,958	**3,917,753**
2033	1,531,635	1,441,254	753,176	157,196	3,946	**3,887,207**
2034	1,523,973	1,441,061	749,436	157,086	3,946	**3,875,501**
2035	1,520,091	1,442,724	748,469	157,033	3,946	**3,872,264**
2036	1,528,896	1,447,477	749,604	157,047	3,958	**3,886,982**
2037	1,529,356	1,447,673	746,146	156,771	3,946	**3,883,892**
2038	1,537,274	1,455,963	747,027	156,579	3,946	**3,900,789**
2039	1,551,443	1,464,098	746,962	157,040	3,946	**3,923,488**
2040	1,569,387	1,481,238	749,544	157,329	3,958	**3,961,454**
2041	1,581,156	1,481,808	748,556	157,439	3,946	**3,972,906**
2042	1,606,537	1,491,652	742,156	157,315	3,946	**4,001,605**
Compound Annual Growth Rate						
2024-33	**-0.50%**	**-0.49%**	**-0.72%**	**-0.01%**	**-0.02%**	**-0.52%**
2024-42	**0.02%**	**-0.06%**	**-0.44%**	**0.00%**	**-0.01%**	**-0.10%**

Table A.8 – Forecasted Retail Sales Growth in California, post-DSM

California Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	376,345	232,906	54,770	95,410	1,658	**761,090**
2025	374,646	228,918	53,970	94,253	1,631	**753,419**
2026	373,722	226,296	53,643	93,333	1,615	**748,609**
2027	372,691	224,347	53,351	92,412	1,602	**744,404**
2028	372,904	223,476	53,080	91,544	1,598	**742,601**
2029	370,484	221,334	52,568	90,463	1,587	**736,436**
2030	369,901	220,209	52,241	89,368	1,582	**733,302**
2031	368,511	218,594	51,858	87,885	1,578	**728,426**
2032	368,024	218,000	51,707	86,030	1,580	**725,341**
2033	365,118	216,085	51,301	84,033	1,574	**718,111**
2034	363,645	214,991	51,113	82,425	1,573	**713,747**
2035	362,994	214,268	50,975	81,232	1,572	**711,041**
2036	363,704	213,426	51,090	80,048	1,576	**709,843**
2037	361,226	211,507	50,815	78,668	1,571	**703,787**
2038	360,660	211,315	50,682	77,270	1,570	**701,498**
2039	361,102	210,364	50,669	76,011	1,570	**699,715**
2040	362,086	211,499	50,618	74,631	1,575	**700,409**
2041	360,656	210,852	50,306	73,201	1,570	**696,584**
2042	362,167	210,457	50,226	71,747	1,570	**696,167**
Compound Annual Growth Rate						
2024-33	**-0.34%**	**-0.83%**	**-0.72%**	**-1.40%**	**-0.57%**	**-0.64%**
2024-42	**-0.21%**	**-0.56%**	**-0.48%**	**-1.57%**	**-0.30%**	**-0.49%**

Table A.9 – Forecasted Retail Sales Growth in Utah, post-DSM

Utah Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	8,044,158	11,601,120	7,584,303	241,504	50,329	**27,521,414**
2025	8,184,798	12,108,572	7,824,271	239,686	48,642	**28,405,969**
2026	8,322,690	12,993,901	6,552,088	238,852	47,672	**28,155,204**
2027	8,475,372	14,374,976	6,557,172	237,330	47,081	**29,691,932**
2028	8,648,984	17,143,145	6,562,389	235,938	46,862	**32,637,319**
2029	8,760,307	17,382,865	6,528,435	234,780	46,522	**32,952,910**
2030	8,884,515	18,004,112	6,522,459	233,524	46,402	**33,691,012**
2031	8,968,745	18,277,853	6,517,340	232,059	46,332	**34,042,329**
2032	9,078,372	18,046,433	6,517,560	230,470	46,423	**33,919,259**
2033	9,119,563	18,080,729	6,511,359	228,901	46,268	**33,986,820**
2034	9,212,741	18,071,133	6,494,788	227,711	46,254	**34,052,628**
2035	9,267,597	18,100,907	6,494,316	226,988	46,246	**34,136,055**
2036	9,450,409	18,101,571	6,484,776	225,810	46,373	**34,308,939**
2037	9,590,337	18,070,692	6,443,531	223,793	46,239	**34,374,592**
2038	9,685,086	18,113,815	6,504,625	222,814	46,238	**34,572,578**
2039	9,966,370	18,095,113	6,492,886	222,240	46,237	**34,822,845**
2040	10,170,049	18,158,012	6,515,025	221,329	46,368	**35,110,783**
2041	10,426,605	18,074,355	6,525,459	219,823	46,236	**35,292,478**
2042	10,787,650	18,042,629	6,487,029	218,242	46,236	**35,581,787**
Compound Annual Growth Rate						
2024-33	**1.40%**	**5.05%**	**-1.68%**	**-0.59%**	**-0.93%**	**2.37%**
2024-42	**1.64%**	**2.48%**	**-0.86%**	**-0.56%**	**-0.47%**	**1.44%**

Table A.10 – Forecasted Retail Sales Growth in Idaho, post-DSM

Idaho Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	784,413	545,807	1,689,601	685,232	2,691	**3,707,744**
2025	784,366	544,739	1,688,371	683,719	2,647	**3,703,842**
2026	784,715	544,373	1,688,312	684,273	2,593	**3,704,265**
2027	783,715	543,797	1,687,767	684,004	2,511	**3,701,794**
2028	782,571	545,468	1,686,184	684,592	2,403	**3,701,218**
2029	771,773	541,994	1,683,225	685,465	2,246	**3,684,702**
2030	762,271	538,681	1,682,323	686,442	2,068	**3,671,784**
2031	749,873	536,634	1,679,416	687,886	1,880	**3,655,688**
2032	738,061	535,740	1,678,499	688,862	1,709	**3,642,871**
2033	720,199	531,401	1,676,103	689,461	1,557	**3,618,721**
2034	706,735	530,090	1,673,407	690,352	1,445	**3,602,029**
2035	692,578	529,337	1,671,811	692,055	1,366	**3,587,147**
2036	685,158	529,991	1,670,468	693,131	1,317	**3,580,066**
2037	672,116	530,845	1,666,797	692,626	1,279	**3,563,662**
2038	657,883	534,191	1,668,270	694,303	1,257	**3,555,904**
2039	653,451	534,107	1,667,508	695,752	1,244	**3,552,061**
2040	648,666	539,676	1,667,303	697,053	1,239	**3,553,937**
2041	643,490	535,618	1,666,775	696,478	1,231	**3,543,592**
2042	646,050	537,030	1,661,863	696,748	1,228	**3,542,917**
Compound Annual Growth Rate						
2024-33	**-0.94%**	**-0.30%**	**-0.09%**	**0.07%**	**-5.90%**	**-0.27%**
2024-42	**-1.07%**	**-0.09%**	**-0.09%**	**0.09%**	**-4.27%**	**-0.25%**

Table A.11 – Forecasted Retail Sales Growth in Wyoming, post-DSM

Wyoming Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2024	1,019,079	1,365,118	6,574,122	31,006	11,978	**9,001,304**
2025	1,000,829	1,358,131	6,656,371	30,925	11,762	**9,058,017**
2026	986,246	1,337,228	6,674,597	30,831	11,483	**9,040,385**
2027	972,153	1,320,899	6,711,894	30,780	11,067	**9,046,794**
2028	962,048	1,312,525	6,740,071	30,839	10,514	**9,055,997**
2029	941,364	1,288,059	6,741,183	30,858	9,718	**9,011,183**
2030	924,619	1,271,986	6,733,713	30,996	8,813	**8,970,127**
2031	900,877	1,251,755	6,767,067	31,060	7,857	**8,958,617**
2032	887,682	1,243,655	6,769,470	31,164	6,985	**8,938,956**
2033	861,392	1,214,067	6,798,442	31,185	6,213	**8,911,299**
2034	850,627	1,209,257	6,798,538	31,282	5,643	**8,895,346**
2035	838,884	1,198,832	6,812,883	31,326	5,241	**8,887,167**
2036	841,061	1,196,174	6,832,104	31,394	4,989	**8,905,721**
2037	835,172	1,191,388	6,822,804	31,315	4,799	**8,885,478**
2038	839,195	1,174,889	6,844,128	31,305	4,689	**8,894,206**
2039	847,568	1,167,650	6,859,250	31,552	4,621	**8,910,642**
2040	853,608	1,161,005	6,894,719	30,922	4,595	**8,944,848**
2041	863,018	1,144,179	6,896,311	30,841	4,554	**8,938,903**
2042	926,862	1,170,731	6,825,714	31,383	4,538	**8,959,228**
Compound Annual Growth Rate						
2024-33	**-1.85%**	**-1.29%**	**0.37%**	**0.06%**	**-7.03%**	**-0.11%**
2024-42	**-0.53%**	**-0.85%**	**0.21%**	**0.07%**	**-5.25%**	**-0.03%**

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