2025
Integrated Resource Plan (Draft)

Volume I - December 31, 2024

PacifiCorp

This 2025 Draft Integrated Resource Plan is based upon the best available information at the time of preparation. The 2025 Integrated Resource Plan is anticipated to be distributed March 31, 2025.

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CHAPTER 1 – EXECUTIVE SUMMARY

Maintaining customer focus

Our draft 2025 Integrated Resource Plan (IRP) is a roadmap for continual progress in safely, reliably and affordably serving over 2 million customers across six states. This roadmap continues to deliver on PacifiCorp's commitments to the diverse communities in which it operates.

Roadmap

Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP as given accomplishments:

- The Energy Gateway South transmission line—a new 416-mile, high-voltage 500-kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in the fourth quarter of 2024.

- The Energy Gateway West Subsegment D1 project—a new high-voltage 230-kV transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in fourth quarter of 2024.

These projects laid the groundwork for long-term affordability and reliability and helping build a more resilient grid.

- The following resources are added in the draft 2025 IRP:
  - 6,379 megawatts of new wind resources
  - 7,668 megawatts of storage resources, including four-hour, eight-hour, and 100-hour durations
  - 5,492 megawatts of new solar resources
  - 500 megawatts of advanced nuclear (Natrium™ reactor demonstration project)

Customer Programs

- 5,149 megawatts of capacity saved through energy efficiency programs
- 1,052 megawatts of capacity saved through direct load control programs

Transmission

- Various upgrades to increase the transfer capability from southern Utah to the major load center in the Wasatch Front

- New transmission from the Walla Walla substation near Walla Walla, Washington to the Wine Country substation near Sunnyside, Washington

- 120 miles of new transmission from the Fry substation near Albany, Oregon to a new substation in Deschutes County, Oregon
- New transmission, including lines from the Fry substation near Albany, Oregon and from the Dixonville substation near Roseburg, Oregon, each connecting to a substation near Lebanon, Oregon
- A second 416-mile transmission line from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South 2)
- Additional local transmission upgrades to connect clean resources to the transmission system in southern Utah, southern and central Oregon, the Willamette Valley in Oregon, and in Yakima and Walla Walla, Washington

Changes to our Portfolio

- Continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030
- Continue to evaluate carbon capture and sequestration options for Jim Bridger Units 3 and 4 in Rock Springs, Wyoming, for completion by 2030
- Continue the process of coal-to-gas conversion of Naughton Units 1 and 2 in Kemmerer, Wyoming, for completion by 2026
- Continue to evaluate coal-to-gas conversion of Dave Johnston Units 1 and 2 in Glenrock, Wyoming, for completion by 2029
- Retire Dave Johnston Unit 3 in Glenrock, Wyoming, in 2027

PacifiCorp's Integrated Resource Plan Approach

In the 2025 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency and demand response programs.

At the same time, the preferred portfolio is responsive to the rapidly expanding arena of new state and federal regulatory requirements.

The 2025 IRP preferred portfolio demonstrates that reliable service will require investment in transmission infrastructure, new wind and solar resources, the conversion of four coal units to natural gas peaking units, significant demand response and energy efficiency programs, the addition of carbon capture technology on identified coal resources, the addition of an advanced nuclear resource, and the addition of energy storage resources. As discussed in Chapter 8, the 2025 IRP preferred portfolio includes resources necessary for individual state policy compliance and assumes those resources are allocated to the state whose policy necessitated the addition.

The primary objective of the IRP is to identify the best mix of proxy resources to serve customers in the future.[1] Building upon developments initiated in the 2023 IRP Update, PacifiCorp recognizes that the basis for identifying a least-cost, least-risk portfolio varies across its jurisdictions, so the 2025 IRP assesses the cost-effectiveness of individual resources in light of the requirements specific to each jurisdiction. For the 2025 IRP, three distinct sets of jurisdictional requirements were represented:

- Utah, Idaho, Wyoming, and California[2]
  - Cost-effective resources
  - Compliance with Western Resource Adequacy Program (WRAP) capacity requirements for Utah, Idaho, Wyoming, and California load
- Oregon
  - Compliance with energy and emissions requirements from House Bill 2021 (HB2021)
  - Compliance with WRAP capacity requirements for Oregon load
  - Compliance with small-scale renewable capacity standard
- Washington
  - Compliance with clean energy requirements from the Clean Energy Transformation Act (CETA)
  - Compliance with WRAP capacity requirements for Washington load

Resources identified under each jurisdictional view are brought together into an "integrated" portfolio and only allocated to those jurisdictions in which they were identified as cost effective. For each jurisdiction, the best combination of resources is determined through analysis that measures cost and risk. Beyond the costs and risks quantified through modeling, the least-cost, least-risk resource portfolio is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

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

PacifiCorp's 2025 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public-input process began with the first public input meeting in January 2024, representing the earliest IRP cycle kick-off for PacifiCorp.

For the first time, in the 2025 IRP process PacifiCorp developed a full draft document and distributed it to stakeholders on December 31, 2024. The timing and requirements of this draft necessitated coverage of IRP topics in the public input meeting series occur three months earlier than in past planning cycles, reducing the number of public meetings, but also increasing meeting

[1] Proxy resources are not actual projects but indicative projects, with estimated costs, technology, timing and location. Actual project data is evaluated in downstream processes. One key example of such a downstream process is a request for proposals, in which bids are solicited on real-world projects where the costs, technology, timing and location can be known and are subject to negotiation.

[2] While California has a number of policy requirements, PacifiCorp is currently required to demonstrate compliance using system-wide portfolio results.

length and accelerating the timing of the coverage of all topics. Following the kick-off, PacifiCorp hosted stakeholders in seven online public input meetings, with an additional two meetings scheduled to take place after the distribution of the draft. Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2025 IRP. In the 2025 IRP, PacifiCorp also enhanced the connections between stakeholder input and IRP development by providing footnotes which reference stakeholder feedback the company received over the course of this IRP cycle. Links to each publicly available stakeholder feedback form and PacifiCorp response are provided in these footnotes and are provided in Appendix M (Stakeholder Feedback Forms).

As depicted in Figure 1.1, PacifiCorp's 2025 IRP was developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio development process. The portfolio development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the size, type, timing and location of new resources in PacifiCorp's system. The resource portfolios produced for the 2025 IRP were created considering a wide range of potential coal and natural gas retirement dates, options for certain coal units to convert to gas or to retrofit for carbon capture sequestration, and other planning uncertainties.

PacifiCorp then developed variants of the top performing resource portfolio to further analyze impacts of specific resource actions relative to the top performing portfolio. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure comparative cost, risk, reliability and emissions levels. This resource portfolio analysis informed selection of the least-cost and least-risk portfolio, the 2025 IRP preferred portfolio, and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were also analyzed to produce specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp's 2025 IRP Approach

Preferred Portfolio Highlights

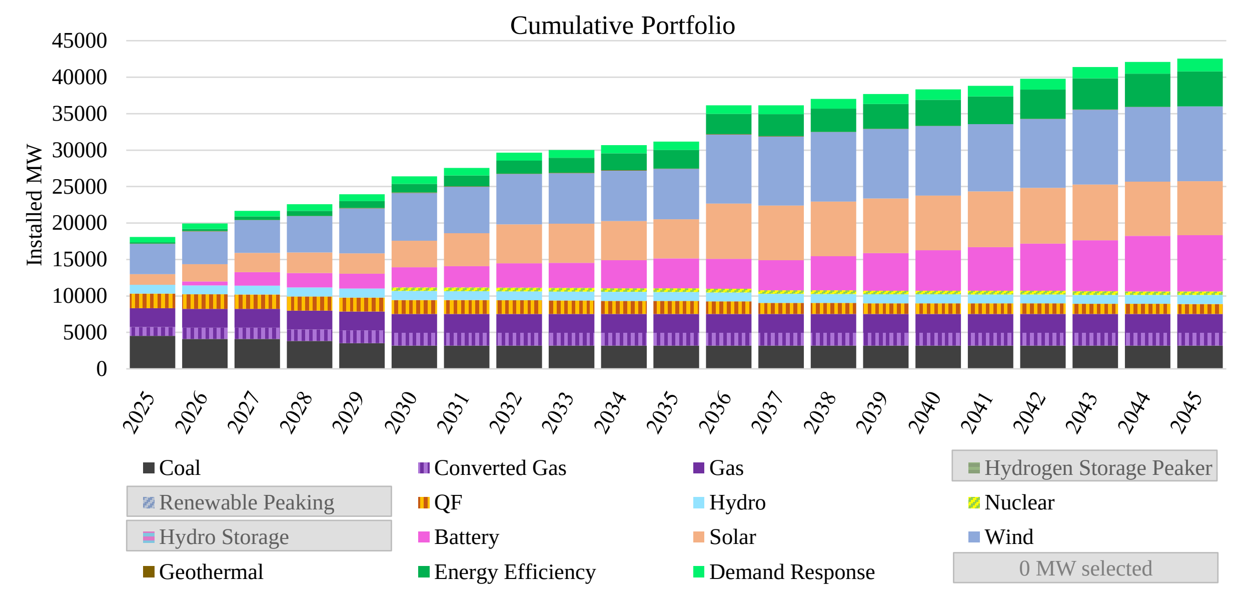
PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in the chapters that follow. Figure 1.2 shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, demand-side management (DSM) resources, storage resources, advanced nuclear, and non-emitting peaking resources facilitated by incremental transmission investments.

The 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 megawatts (MW) of wind, 1,736

MW of solar additions, and 1,072 MW of battery storage capacity. These resources will come online in the 2025 to 2026 timeframe.

The 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by the end of 2030. By the end of 2032, the preferred portfolio includes 2,801 MW of energy storage resources, including 844 MW of iron-air batteries with 100-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 20-year planning horizon, the 2025 IRP preferred portfolio includes 6,379 MW of new wind and 5,492 MW of new solar.

Figure 1.2 – 2025 IRP Preferred Portfolio (Existing and Planned Resources)*



* Technologies highlighted in gray were available for selection in IRP modeling but are not part of PacifiCorp's existing resource mix and were not selected for the preferred portfolio.

The 2025 IRP preferred portfolio includes a second 416-mile transmission line from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah, known as Energy Gateway South 2, planned to come online in 2036. Smaller upgrades increase transfer capability between southern Utah and the Wasatch Front, between Walla Walla and Yakima in Washington, and between the Willamette Valley and Deschutes County in Oregon.

Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Table 1.1 summarizes the incremental transmission projects in the 2025 IRP preferred portfolio. Note, at this time, the Boardman-to-Hemingway transmission line (B2H) is not included in the preferred portfolio. PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Table 1.1 – Transmission Projects Included in the 2025 IRP Preferred Portfolio [1,2]

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026	Rebuild existing Cameron - Sigurd 138 kV	250	250	250	30	100%	Utah South	Wasatch Front
2027	Cluster 1 Area 11 - Willamette Valley	0	0	199	13	100%	n/a	n/a
	Serial queue - Central Oregon	0	0	152	3	100%	n/a	n/a
2028	Cluster 2 Area 23 - Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 1/2/3 - Walla Walla	0	0	628	66	100%	n/a	n/a
2031	Cluster 1/2/3 - Walla Walla	0	0	393	348	100%	n/a	n/a
	Walla Walla - Wine Country 230 kV	400	400	400	145	100%	n/a	n/a
2032	Cluster 1 Area 14 - Summer Lake	400	400	400	120	100%	Summer Lake	Hemingway
	Cluster 2/3 - Willamette Valley - Fry-Full Circle 230 kV	450	450	450	413	100%	Willamette Valley	Central OR
2036	Gateway South 2: Aeolus Clover #2 500 kV	1,500	1,500	1,990	1,810	100%	Wyoming East	Clover
	Huntington – Clover 345 kV	800	800	800	264	100%	Utah South	Wasatch Front
	Spanish Fork - Mercer 345 kV	300	300	300	153	100%	Utah South	Wasatch Front
	West Cedar - Three Peaks 138 kV	200	200	200	14	100%	Utah South	Wasatch Front
	S. Lebanon-Dixonville 500 kV, Dbl-Ckt Fry-S.Lebanon 230 kV	1,500	1,500	665	1,117	100%	Willamette Valley	Southern OR
2041	Serial through Cluster 1 Area 13 - Southern Oregon	0	0	231	52	100%	n/a	n/a
Grand Total		**5,800**	**5,800**	**7,451**	**4,551**			

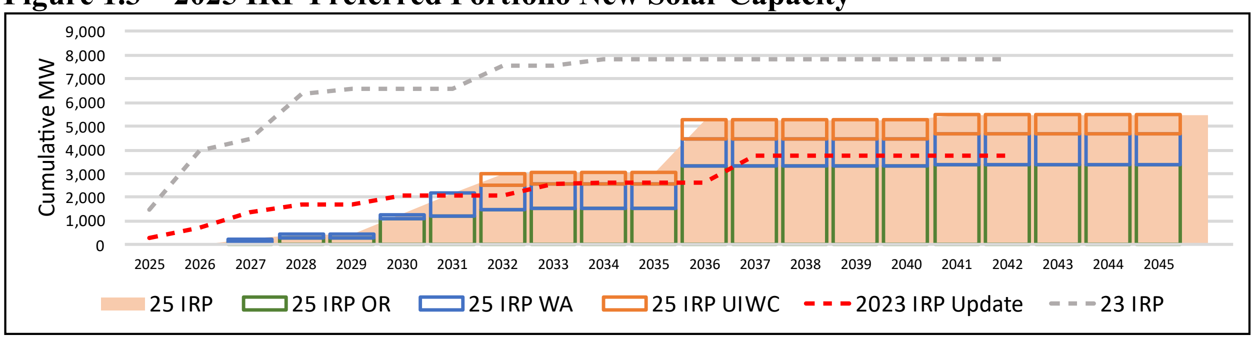
[1] Export and import values represent total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for project-specific timing and some costs are project-specific.

In Volume I, Chapter 9 – Modeling and Portfolio Selection Results, a sensitivity analysis evaluates the impacts of significant new loads coming online in the 2033 timeframe and supports continuing with permitting Energy Gateway segments, as well as initiating preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional transmission expansion segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest).

New Solar Resources

The 2025 IRP draft preferred portfolio includes 245 MW of new solar by the end of 2027, 1,275 MW by the end of 2030, and 5,492 MW by the end of 2045, as shown in Figure 1.3.

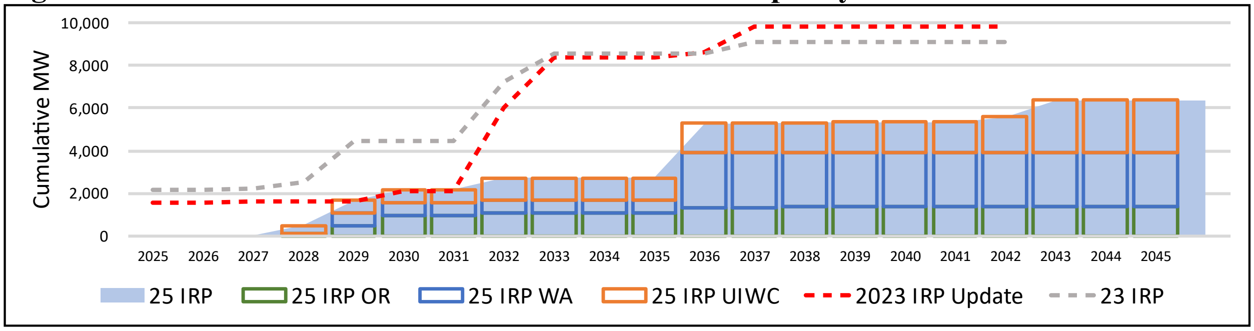
Figure 1.3 – 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 1.4, PacifiCorp's 2025 IRP draft preferred portfolio includes 486 MW of new wind generation by the end of 2028, 2,175 MW by the end of 2030, and 6,379MW of cumulative new wind by the end of 2045.

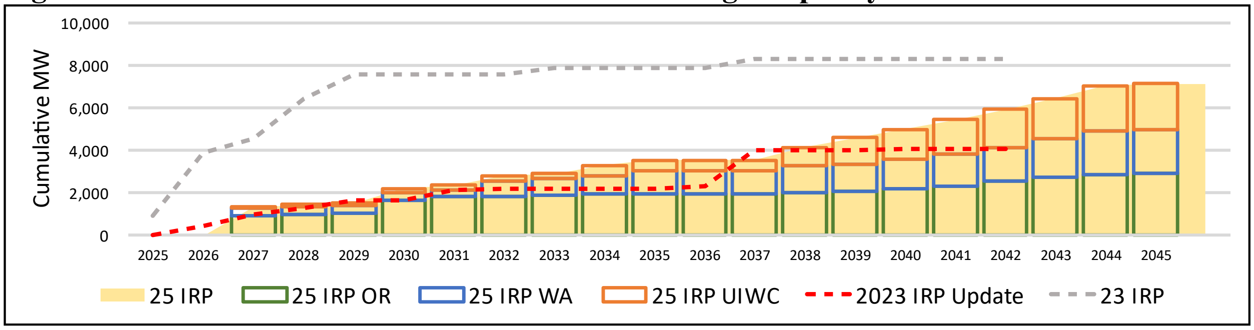
Figure 1.4 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

New storage resources in the 2025 IRP draft preferred portfolio are summarized in Figure 1.5. The 2025 IRP draft preferred portfolio includes 1,818 MW of new storage resources by the end of 2027[2] including both 4- and 8-hour lithium-ion storage. By year-end 2030, the 2025 draft IRP includes 2,716 MW of storage which includes nearly 656 MW of 100-hour iron air storage, and by year-end 2045, the 2025 IRP draft preferred portfolio includes 7,668 MW of new storage.

Figure 1.5 – 2025 IRP Preferred Portfolio New Storage Capacity[1,2]

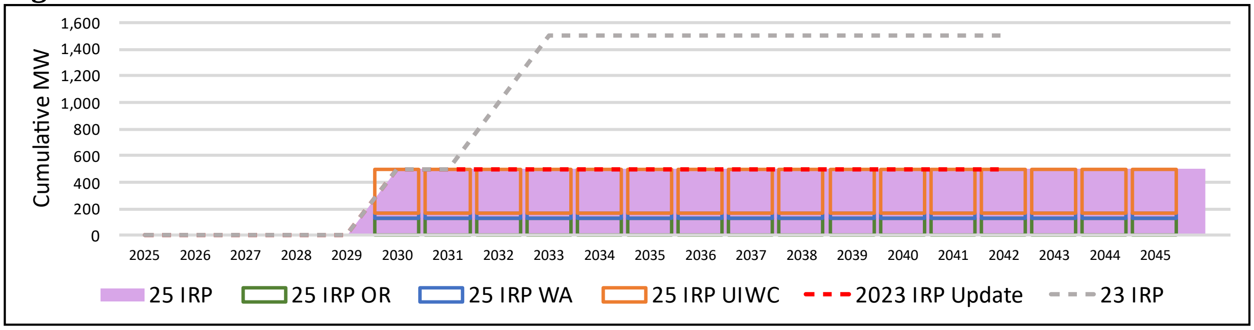


[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and thus is not included as new storage capacity in the 2025 IRP.
[2] The 1,818 MW of new storage resources by the end of 2027 includes 520 MW of signed battery storage contracts that have been committed since the filing of the 2023 IRP Update.

New Nuclear Resources

The 2025 IRP draft includes advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 1.6, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by the end of 2030.

Figure 1.6 – 2025 IRP New Nuclear



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 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.

PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 3.9 percent and forecasted coincident system peak is down 0.6 percent when compared to the 2023 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.03 percent for load and 1.91 percent for peak. Changes to PacifiCorp's load forecast are driven by lower projected demand from new large customers, who are expected to provide or pay for their necessary resources and transmission.

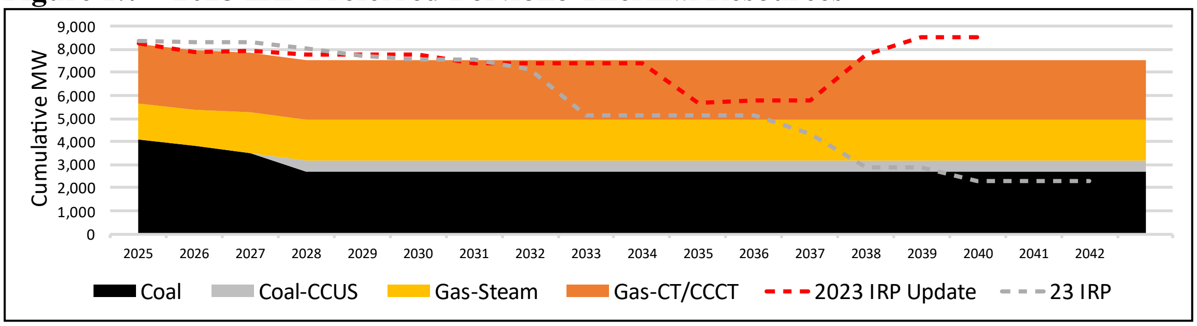
Energy efficiency and demand response programs are important tools for meeting customers' future energy needs. Our innovative approach moves beyond management based on peak loads and focuses on turning demand-response resources into dynamic operating reserves. That's why we're expanding existing demand-response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

- In the near-term years of 2025 through 2028, our ongoing conservation and cost-effective demand-response initiatives will seek to deliver:
    - 678 megawatts of energy efficiency between 2025 and 2028
    - 213 megawatts of demand response between 2025 and 2028

Coal and Gas Exits, Retirements, and Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the WEIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 1.7, the 2025 IRP converts 562 MW of coal fueled generation to natural gas fueled, and exits PacifiCorp's share in 386 MW of minority-owned coal, and also retires 220 MW of majority-owned coal at Dave Johnston by the end of the study horizon. The balance of the coal units continue to operate through the end of the study horizon, with 700 MW at Jim Bridger 3 and 4 converting to carbon capture in 2030.

Figure 1.7 – 2025 IRP Preferred Portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 1.2. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.

Table 1.2 – 2025 IRP Coal Resource Results Summary

Majority-Owned Coal		
Unit	2023 IRP Update Retirement Year	2025 IRP Retirement Year
	As Selected	As Selected
Dave Johnston 1 & 2	2028 (Coal ash compliance)	Not retired (Gas conversion 2029)
Dave Johnston 3	2027 (Clean air compliance)	2027 (Clean air compliance)
Dave Johnston 4	2039 (Assumed end of life)	Not retired
Hunter 1-3	2042 (Assumed end of life)	Not retired
Huntington 1 & 2	2036 (Assumed end of life)	Not retired
Jim Bridger 1 & 2	2037 (Gas conversion 2024/Assumed end of life)	Not retired (Gas conversion 2024)
Jim Bridger 3 & 4	2039 (CCS/Assumed end of life)	Not retired (CCS)
Naughton 1 & 2	2036 (Gas conversion 2026/Assumed end of life)	Not retired (Gas conversion 2026)
Wyodak	2039 (Assumed end of life)	Not retired (Coal)

Minority-Owned Coal		
Unit	2023 IRP Update Retirement Year	2025 IRP Retirement Year
	As Input	As Input
Colstrip 3	2025 (Transfer capacity to unit 4)	2025 (Transfer capacity to unit 4)
Colstrip 4	2029 (PacifiCorp exit)	2029 (PacifiCorp exit)
Craig 1	2025 (Assumed end of life)	2025 (Assumed end of life)
Craig 2	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 1	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 2	2027 (Assumed end of life)	2027 (Assumed end of life)

Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take primarily over the next 2-4 years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public-input process. Table 1.3 details specific 2025 IRP action items by resource category.

Table 1.3 – 2025 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Colstrip Units 3 and 4:** • PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2025 IRP preferred portfolio target exit date of December 31, 2025.
1c	**Naughton Units 1 and 2:** • PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**Carbon Capture and Storage / Low Carbon Portfolio Standard:** • PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard.
1e	**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.

Action Item	1. Existing Actions (continued)
1f	**<u>Natrium™ Demonstration Project:</u>** • By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones 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.
1g	**<u>Ozone Transport Rule Compliance:</u>** • 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. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments.
1h	**<u>Natural Gas Emissions Compliance Strategies</u>** • The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon's HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from 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 will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025.
2b	**2025 All-Source Request for Proposals:** • PacifiCorp will issue as appropriate by jurisdiction need, one or more all-source Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3] • In light of the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

Action Item	3. Transmission Action Items
3a	**Local Reinforcement Projects** Initiate local reinforcement projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids.
3b	**Gateway West Support** Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

[3] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Oregon Public Utilities Commission)

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th></tr>
<tr><td>4a</td><td><u>Energy Efficiency Targets:</u>
PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp’s state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP.
PacifiCorp will pursue cost-effective energy efficiency resources.
PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio. Capacity impacts for demand response include both summer and winter impacts within a year.</td></tr>
<tr><th>Action Item</th><th>5. Market Purchases</th></tr>
<tr><td>5a</td><td><u>Market Purchases:</u>
PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means:
Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.
Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.
Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.</td></tr>
</table>

<table>
<tr><th>Action Item</th><th>6. Renewable Energy Credit (REC) Actions</th></tr>
<tr><td>6a</td><td><u>Renewable Portfolio Standards (RPS):</u>
PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements.
PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.</td></tr>
</table>

6b	**<u>Renewable Energy Credit Sales:</u>** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

CHAPTER 2 – INTRODUCTION

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

In recent integrated resource planning cycles, there has been increased focus on individual state jurisdictional outcomes aligned with both stakeholder and regulatory interest, and state legislation and rulemaking. In an effort to recognize and respect this trend, PacifiCorp's 2025 IRP enhances jurisdictional portfolio development and reporting leading to the integration of results into the preferred portfolio. Chapter 8 (Modeling and Portfolio Evaluation) describes the fundamental methodologies used to arrive at state-level initial portfolios and how they are subsequently integrated to form a single coherent plan.

PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public input process, described in the chapters that follow. Chapter 9 (Modeling and Portfolio Selection Results), shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources (including iron-air technology with 100- hour storage duration), and advanced nuclear.[1]

The 2025 IRP preferred portfolio is in addition to contracted resources, many of which are located in Utah. The 100 MW Hornshadow I Solar and 200 MW Hornshadow Solar II facilities are set to come online in 2025, while two facilities combining solar and storage are set to come online in 2025 and 2026: Faraday with 525 MW solar and 150 MW storage and Green River with 400 MW solar and 400 MW storage. Finally, Oregon's Community Solar Program has ten small-scale solar facilities scheduled to come online in 2025 and 2026, totaling approximately 18 MW.

The 2025 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 6,379 MW of new wind, 5,492 MW of new solar and 7,668 MW of new storage resources.

New storage includes five battery facilities totaling 520 MW are projected to come online ahead of the peak summer season in 2026: Dominguez BESS (200 MW), Enterprise BESS (80 MW), Escalante BESS (80 MW), Granite Mountain BESS (80 MW) and Iron Springs BESS (80 MW). These signed battery storage contracts were committed since the filing of the 2023 IRP update.

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission projects which are described in

[1] See Chapter 7 (Resource Options)

Volume I, Chapter 1 (Executive Summary), Chapter 4 (Transmission), and Chapter 9 (Modeling and Portfolio Selection Results).

Other significant analysis to support the 2025 IRP includes:

- An updated demand-side management resource conservation potential assessment
- A distributed generation study for PacifiCorp's service territory
- A flexible reserve study
- An updated plant water consumption study
- An energy storage potential evaluation
- An assessment of grid enhancement technologies
- Historic weather years
- An updated load and resource balance

This chapter outlines the components of the 2025 IRP, summarizes the role of the IRP, and provides an overview of the public input process.

2025 Integrated Resource Plan Components

The basic components of PacifiCorp's 2025 IRP include:

- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities; Volume I, Chapter 3 (Planning Environment)
- Description of PacifiCorp's transmission planning efforts and activities; Volume I, Chapter 4 (Transmission)
- Regional resource adequacy assessments, wildfire mitigation planning and the role of transmission in system reliability and incident recovery; Volume I, Chapter 5 (Reliability and Resiliency)
- Load and resource balance on a capacity and energy basis and determination of the load and energy positions for the front ten years of the twenty-year planning horizon; Volume I, Chapter 6 (Load and Resource Balance)
- Profile of resource options considered for addressing future capacity and energy needs; Volume I, Chapter 7 (Resource Options)
- Description of IRP modeling, including a description of the portfolio development process, cost and risk analysis, and preferred portfolio selection process; Chapter 8 (Modeling and Portfolio Evaluation)
- Presentation of IRP modeling results and selection of PacifiCorp's preferred portfolio; Volume I, Chapter 9 (Modeling and Portfolio Selection Results)
- Presentation of PacifiCorp's 2025 IRP action plan linking the company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource procurement risks; Volume I, Chapter 10 (Action Plan)

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

- Load Forecast (Volume II, Appendix A)
- Regulatory Compliance (Volume II, Appendix B)

- Public Input (Volume II, Appendix C)
- Demand-Side Management (Volume II, Appendix D)
- Grid Enhancement (Volume II, Appendix E)
- Flexible Reserve Study (Volume II, Appendix F)
- Plant Water Consumption Study (Volume II, Appendix G)
- Capacity Expansion Results (Volume II, Appendix I)
- Distributed Generation Study (Volume II, Appendix L)
- Stakeholder Feedback Forms (Volume II, Appendix M)
- Washington Clean Energy Action Plan (Volume II, Appendix O)
- Acronyms (Volume II, Appendix P)

PacifiCorp is also providing data disks for the 2025 IRP. These electronically provided materials support and provide additional details for the analysis described within the document. Data disks are generated for public, confidential, and highly confidential data to be provided as appropriate to each recipient.[2] Confidential and highly confidential data access are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings. The "Highly Confidential" data disk category, adopted in the prior 2023 IRP planning cycle, allows the company to provide the maximum amount of access to parties who are not participants in commercial developments or those who have direct conflicts of interest regarding commercially sensitive information.

The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP establishes a proxy resource plan capable delivering adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[3] In this way, the IRP serves as a roadmap for determining and implementing PacifiCorp's long-term resource strategy. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting request for proposal bid evaluation efforts. As an external communications tool, the IRP engages stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

Public input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public input process allowing stakeholder involvement in all phases of plan development. PacifiCorp organized held seven public input meetings, spanning one or two days each, to facilitate information sharing, collaboration, and expectations for the 2025 IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed.

[2] The Draft 2025 IRP is supported by a public data disk only.

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

In addition to the public input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and stakeholder input throughout the IRP process. The IRP webpage is accessible using the following link:

www.pacificorp.com/energy/integrated-resource-plan.html

Messages relevant to PacifiCorp's IRP can sent to the following email address:

irp@pacificorp.com

Additionally, a stakeholder feedback form provides opportunities for stakeholders to submit additional input and ask questions throughout the 2025 IRP public input process. The submitted forms, as well as PacifiCorp's responses to these feedback forms are located on the PacifiCorp's IRP website:

www.pacificorp.com/energy/integrated-resource-plan/comments.html

Summaries of stakeholder feedback forms received, and company responses were provided throughout the public input meeting series and are also available in Appendix M (Stakeholder Feedback Forms). In the 2025 IRP, links to stakeholder feedback forms are provided in footnotes to further tie together stakeholder feedback with the development of the filed IRP. Appendix C (Public Input Process) reports additional details regarding engagement for the 2025 IRP.

CHAPTER 3 – PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- Federal and state tax credits continue to encourage the procurement of wind and solar resources, which will likely dominate U.S. capacity additions for the next decade. Flexible generation, transmission, new storage technologies, and market design changes will be need to better integrate these resources into the grid.
- The Federal Inflation Reduction Act (IRA) was enacted on August 16, 2022, creating technology specific tax credits for projects placed in service after December 31, 2021, and technology neutral tax credits for projects placed in service after December 31, 2024. Eligible resources include any technology that generates electricity and does not emit greenhouse gases. The IRA is modeled in all 2025 IRP studies. As of December 2024, the future of some provisions of the IRA remains unknown under the new administration.
- 2024 saw significant new environmental regulation with potential impacts to PacifiCorp's generation resources. These included Greenhouse Gas (GHG) emission standards for existing coal-fired and new gas-fired plants, Mercury and Air Toxics Standards (MATS) revisions, Effluent Limitations Guidelines revisions, Coal Combustion Residuals legacy rule, and the NEPA Phase 2 rule.
- In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA), which requires that 100% of electricity sales in Washington be 100% renewable and non-emitting by 2045. PacifiCorp filed its inaugural Clean Energy Implementation Plan (CEIP) in December 2021, and expects to file its second CEIP in October 2025, detailing the company's action plan for the next four-year period.
- In 2021, Washington passed the Climate Commitment Act, which establishes a cap-and-invest program that was implemented through the regulatory rulemaking process in 2022 and came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities that are subject to CETA are allocated allowances commensurate with emissions associated with Washington retail load at no cost. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.
- In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. The 2025 IRP includes modeling to support House Bill 2021 which will be expanded upon in PacifiCorp's Oregon Clean Energy Plan submission to be filed within 180 days of the 2025 IRP.

  PacifiCorp and the California Independent System Operator Corporation (CAISO) launched the voluntary western energy imbalance market (WEIM) November 1, 2014, the first western energy market outside of California. Since inception, The WEIM's footprint has grown significantly, generating $3.4 billion in monetary benefits to customers of participating entities. ($1.42 billion total footprint-wide benefits as of August 2, 2021). A significant contributor to EIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area. Building on the success of WEIM, in 2022 PacifiCorp, along with CAISO and other stakeholders, collaborated to develop a market design for an extended day ahead market (EDAM) that CAISO plans to launch in 2025.

Introduction

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

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

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

Wholesale Electricity Markets

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

PacifiCorp actively participates in the wholesale market by making purchases and sales to minimize costs and to keep its supply portfolio in balance with customers' expectations. This interaction with the market takes place on time scales ranging from sub-hourly to years in advance. Without the wholesale market, PacifiCorp – or any other load serving entity – would need to construct or own an unnecessarily large margin of supplies that would go unused in all but the most unusual circumstances and would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand.

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

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

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

In 2018, the Federal Energy Regulatory Commission (FERC) directed regional transmission organizations (RTO) and independent system operators (ISO) to develop market rules for the participation of energy storage in wholesale energy, capacity, and ancillary services markets[3]. The FERC gave operators nine months to file tariffs and another year to implement – essentially opening wholesale markets to energy storage. Operators' proposed tariffs have varied substantially among regions with PJM requiring a 10-hour continuous discharge capability while New England requires a continuous 2-hour capability. Later, in May 2019, the FERC issued an order generally affirming the earlier order to establish reforms to remove barriers to the participation of electric storage resources in certain organized wholesale markets. PacifiCorp continues to evaluate the cost effectiveness of several energy storage systems, including pumped storage, stand-alone Li-ion batteries, flow batteries, iron-air storage and other long-duration storage, as well as energy storage co-located with generating resources.

Increased renewable generation has also contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the Energy Imbalance

[1] California, New Jersey, New York, Massachusetts, Oregon, Nevada, Virginia, Connecticut, and Maine have either mandated or set energy storage targets, while Arizona is considering the implementation of targets.

[2] In addition to Elkhorn, PG&E has contracts for more than 3,330 MW of battery storage being deployed statewide through 2024, more than 900 MW of which has been connected to California's electric grid. The Mercury News, March 8, 2023; PG&E ushers in landmark Tesla battery energy storage system at Moss Landing (mercurynews.com)

[3] 162 FERC ¶ 61,127 United States of American Federal Energy Regulatory Commission, 18 CFR Part 35 [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841] *Electric Storage Participation in Markets Operated by Regional Transmission;* Organizations and Independent System Operator (Issued February 15, 2018)

Market (EIM). The EIM became operational November 1, 2014, and since that time has seen NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, Powerex, Idaho Power, Balancing Authority of Northern California, Salt River Project, Seattle City Light, Los Angeles Department of Water and Power, Northwestern Energy, and Public Service Company of New Mexico, Avista Utilities, Tucson Electric Power, Turlock Irrigation District, Tacoma Power, Bonneville Power Administration, Avangrid Renewables, El Paso Electric, and Western Area Power Administration join the EIM. Black Hills Power plans to join the EIM in 2026. The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and five-minute dispatch. CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. As part of other EIM participating entities, PacifiCorp is also participating in the CAISO stakeholder process to establish an Extended Day-Ahead Market (EDAM), which is currently in the phase of implementation activities and expected to onboard participants in 2026.

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

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

Market participants routinely study demand uncertainties driven by weather and overall economic conditions. The North American Electric Reliability Corporation (NERC) publishes an annual assessment of regional power reliability, and any number of data services are available that track the status of new resource additions[4]. In NERC's latest release, the WECC region was classified as "elevated risk", in which shortfalls may occur in extreme conditions.

The Western Resource Adequacy Program (WRAP)[5] will also provide market participants insight into potential supply constraints and give participants some assurance that sufficient resources have been procured for the program to maintain a 1-in-10-year loss of load expectancy standard. In addition to binding load and resource showings for the upcoming season, the WRAP will conduct advisory two- and five-year resource adequacy assessments for the footprint that will allow participants to better plan for the future needs of their systems. The Forward Showing program will ensure participants procure sufficient resources to meet a footprint wide reliability

[4] 2020 Long-term Reliability Assessment, December 2020, North American Electric Reliability Assessment
[5] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

standard, and the Ops Program will facilitate transfers between entities in a resource deficit and those with excess resources.

In addition to reliability planning, there are externalities that can heavily influence the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Natural gas-fired generation and gas prices have been a critical determinant of western electricity prices, and this is expected to continue over the term of this plan's decision horizon. While the share of natural gas in the resource western resource mix is expected to fall by the end of the horizon because of increasing renewable resource buildout, natural gas will remain on the margin in many hours, particularly critical hours when renewable resource output is limited. Another critical uncertainty that weighs heavily on the 2025 IRP, as in past IRPs, is the uncertainty surrounding future greenhouse gas policies, both federal and/or state. PacifiCorp's official forward price curve (OFPC) does not assume a federal carbon dioxide (CO_2) policy, but other price scenarios developed for the IRP consider impacts of potential future federal and state policies which drive additional costs and restrictions of emissions. However, PacifiCorp's OFPC does include enforceable state climate programs that have been signed into law[6].

Power Market Prices

Mild weather, strong production, and limited exports caused high storage levels in the fossil gas market, resulting in low gas prices throughout 2024. Low fuel prices coupled with mild demand led to an annually averaged 34% decrease in on-peak spot prices across the Non-CAISO WECC trading hubs in 2024, as seen in Table 3.1.

Table 3.1 - 2023 and 2024 Monthly Average On-Peak Spot Prices ($/MWh)

Month	2023	2024	Difference	Percent
Jan	135.23	137.27	2.05	2%
Feb	84.41	41.95	-42.46	-50%
Mar	76.51	25.05	-51.46	-67%
Apr	79.53	18.57	-60.97	-77%
May	21.60	20.48	-1.13	-5%
Jun	38.87	31.13	-7.74	-20%
Jul	93.02	67.88	-25.13	-27%
Aug	88.59	48.50	-40.09	-45%
Sep	51.76	52.55	0.78	2%
Oct	78.57	46.24	-32.33	-41%
Nov	70.90	35.19	-35.71	-50%
Dec	52.12	47.50	-4.62	-9%
Annual	**72.59**	**47.69**	**-24.90**	**-34%**

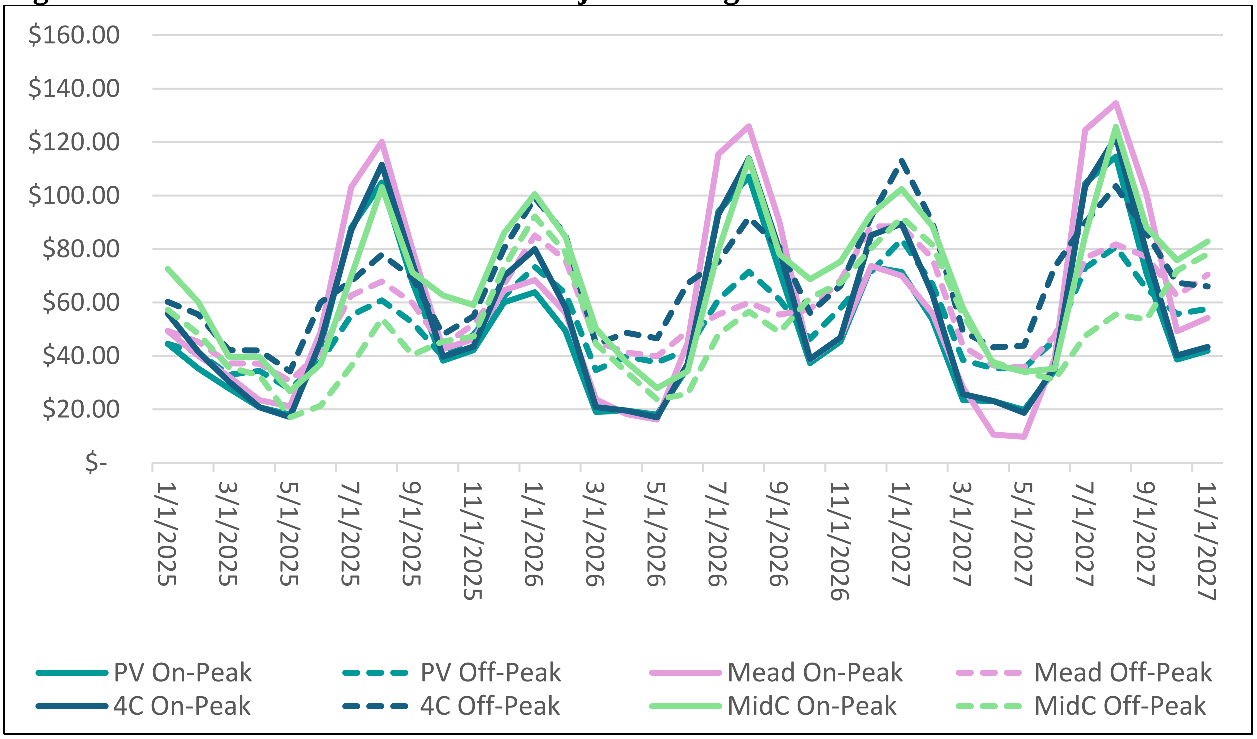
**As of December 16, 2024*

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

Source: SNL

Barring major geo-political disruptions or other sustained economic drivers, forecasted wholesale power prices are expected to increase slightly relative to 2024 peaks and will follow seasonal weather trends with higher prices over the summer months. Broker price spreads indicate August 2025 On-Peak power prices at Palo Verde, Mead, Four Corners, and Mid-Columbia are all trading around $105-$120 per MWh.

Figure 3.1 - Forward Prices at WECC Major Trading Hubs



Source: OTC, Siemens PTI

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

Table 3.2 - 2025-2027 Forward Price Spread ($/MWh)

	Palo Verde		Mead		4 Corners		Mid-Columbia	
Date	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
1/1/2025	$ 44.57	$ 44.53	$ 49.32	$ 49.35	$ 55.87	$ 60.23	$ 72.60	$ 57.25
5/1/2025	$ 18.04	$ 27.62	$ 21.12	$ 30.62	$ 17.05	$ 34.20	$ 26.81	$ 17.02
8/1/2025	$104.89	$ 60.81	$120.14	$ 67.85	$111.56	$ 77.93	$103.20	$ 53.99
11/1/2025	$ 42.14	$ 47.94	$ 46.28	$ 51.86	$ 43.55	$ 54.89	$ 59.08	$ 47.28
1/1/2026	$ 63.81	$ 73.32	$ 68.41	$ 85.12	$ 79.99	$ 99.17	$100.52	$ 92.19
5/1/2026	$ 17.98	$ 37.62	$ 16.18	$ 39.84	$ 17.00	$ 46.59	$ 27.99	$ 23.71
8/1/2026	$107.13	$ 71.57	$125.96	$ 59.86	$113.94	$ 91.72	$113.74	$ 56.61
11/1/2026	$ 45.38	$ 57.92	$ 46.83	$ 68.32	$ 46.89	$ 66.32	$ 75.27	$ 67.37
1/1/2027	$ 71.36	$ 83.56	$ 70.01	$ 88.44	$ 89.44	$113.02	$102.48	$ 91.87
5/1/2027	$ 19.80	$ 35.40	$ 9.73	$ 35.70	$ 18.71	$ 43.83	$ 34.07	$ 34.10
8/1/2027	$114.63	$ 80.80	$134.58	$ 81.71	$121.91	$103.55	$125.72	$ 55.51
11/1/2027	$ 41.95	$ 57.62	$ 54.19	$ 70.41	$ 43.35	$ 65.97	$ 82.83	$ 78.10

Source: OTC

Power Market Dynamics

Non-CAISO WECC Generation and Capacity Mix

The generation mix in the non-CAISO WECC region reflects the influence of individual state RPS and emissions policies. In 2023, natural gas resources provided about 31% of generated energy followed by hydro at 22%, coal at 18%, and wind at 12%. Natural gas and coal share is expected to decrease slightly, with non-hydro renewables expected to replace this energy throughout 2030.

Figure 3.2 - National RPS Targets

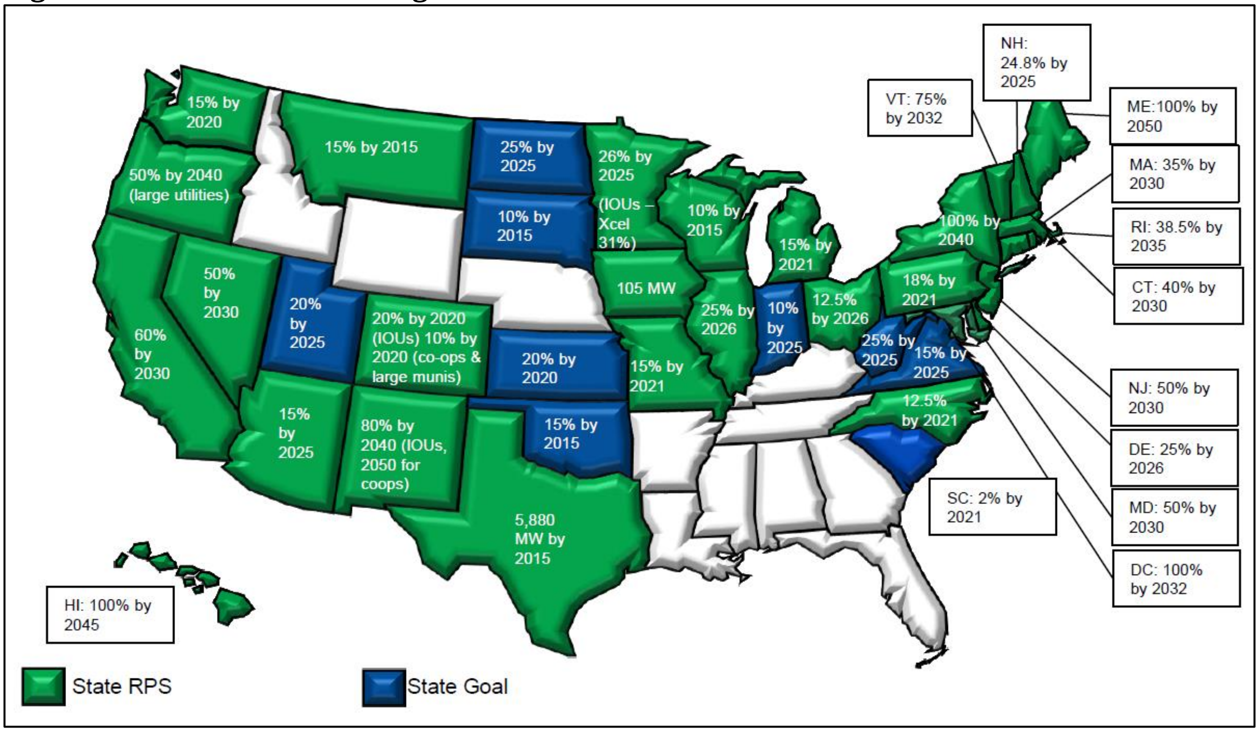
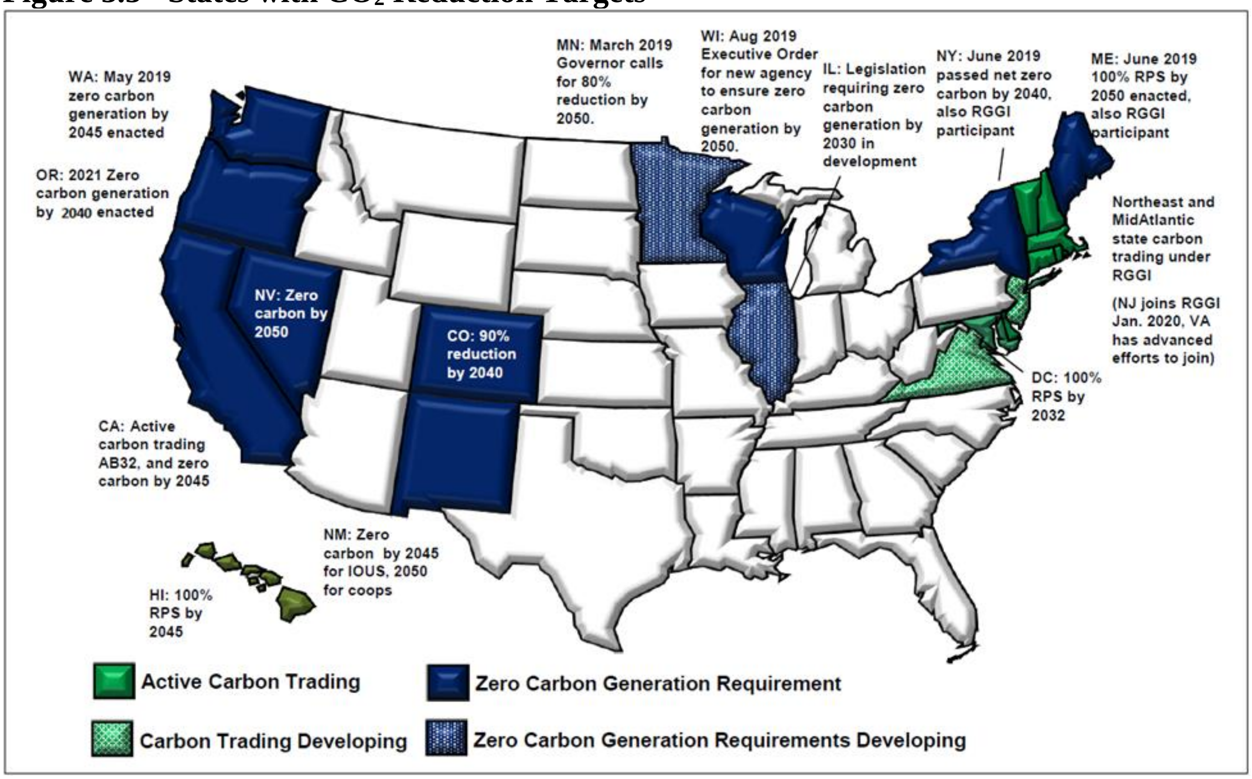
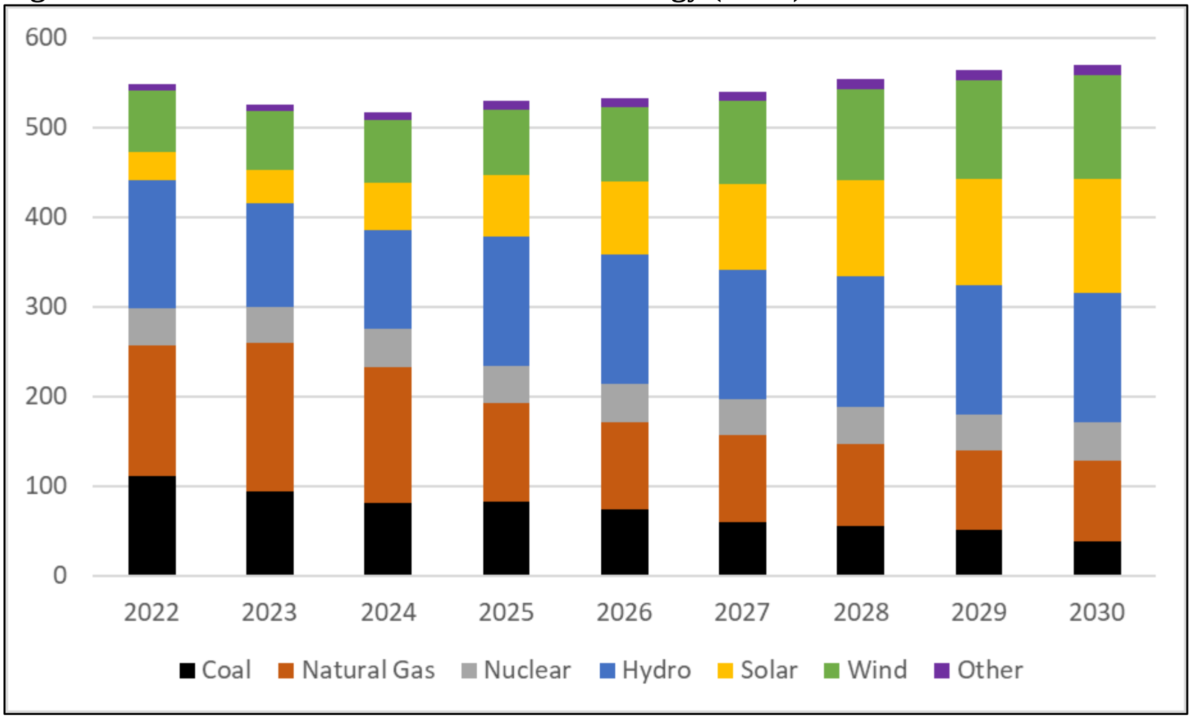


Figure 3.3 - States with CO_2 Reduction Targets



Source: Siemens PTI

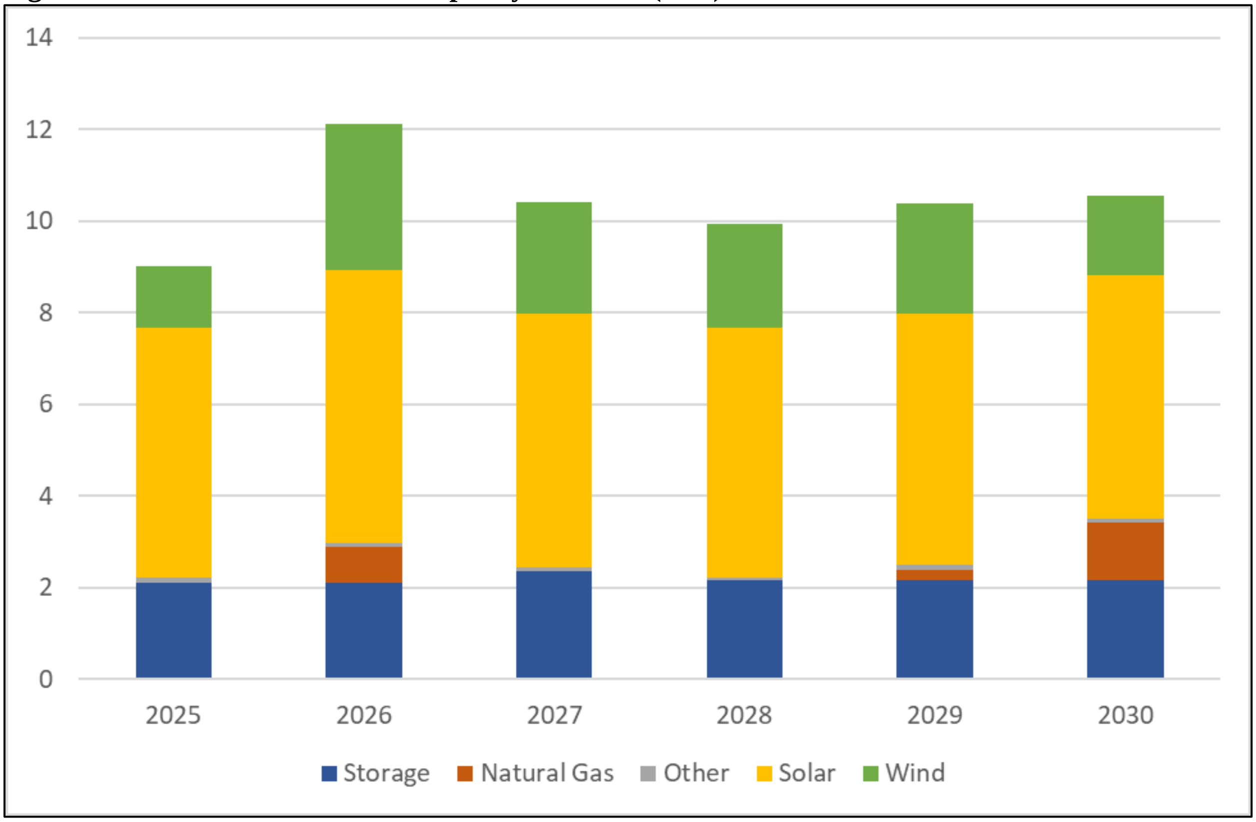
Figure 3.4 - Non-CAISO WECC Generated Energy (TWh)



Source: IHS Markit, SNL, Siemens PTI

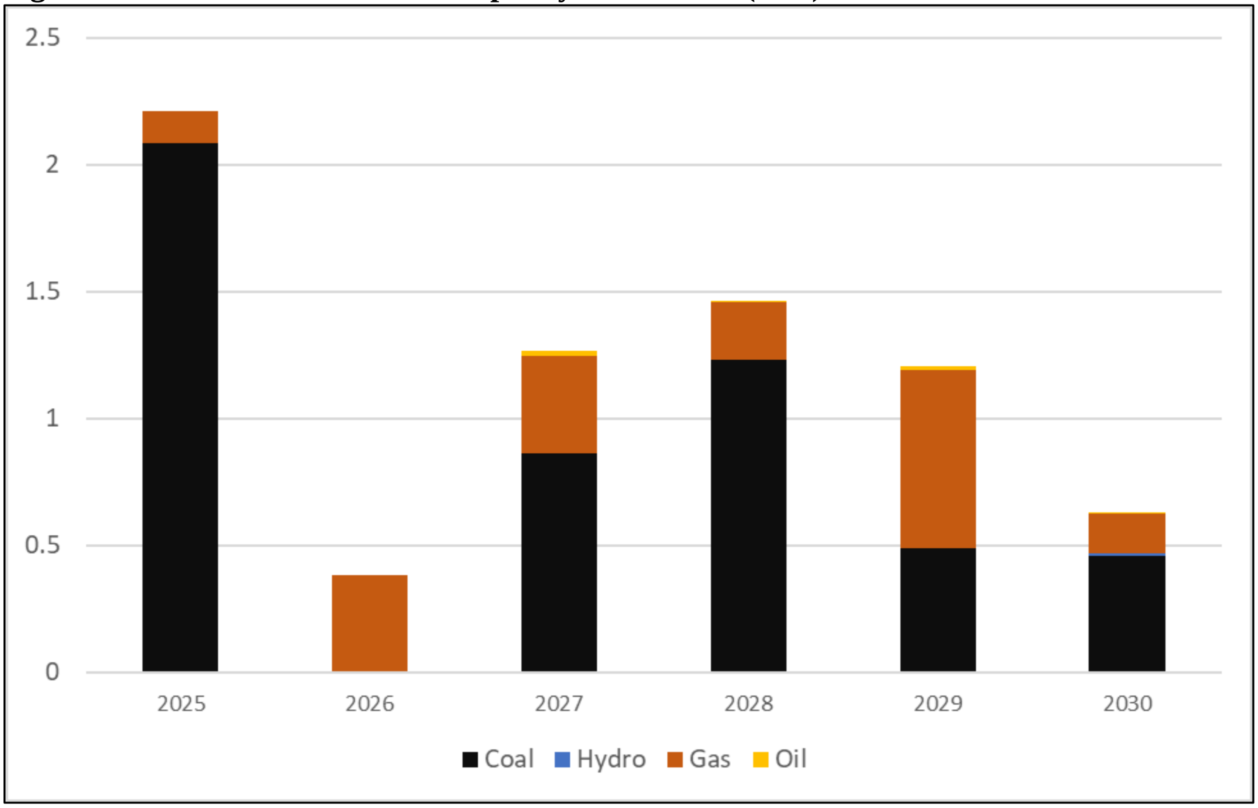
In 2023, 3.5 GW of solar resources and 600 MW of wind were added in the non-CAISO WECC, with similar quantities coming online through October 2024. Into 2025, Siemens expects approximately 3.6 GW of wind and 2.1 GW of solar to come online based on activity in regional interconnection queues. Storage capacity additions have also been significant, with 1.4 GW of storage capacity brought online in 2022 and 1.9 GW online through October 2024. Minimal fossil fuel capacity came online in 2023 and that trend may continue through 2030 if carbon reduction goals continue to drive renewable additions.

Figure 3.5 - Non-CAISO WECC Capacity Addition (GW)



Source: IHS Markit, SNL, Siemens PTI

Figure 3.6 - Non-CAISO WECC Capacity Retirement (GW)



Source: IHS Markit, SNL, Siemens PTI

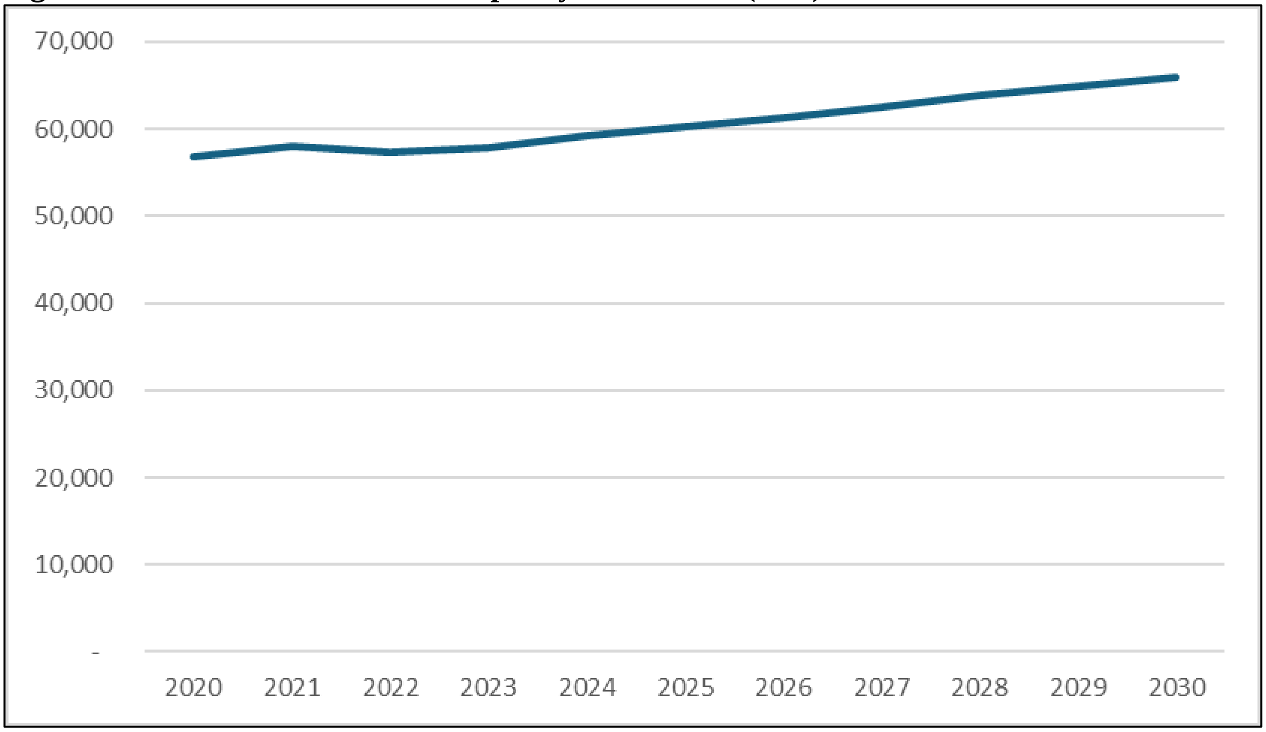
Emissions and Environment

Cool weather and low natural gas prices in 2023 led to decreased emissions and low demand for allowances. In addition, the finalization of the Good Neighbor Plan in March 2023 contributed to an 18% NOx emission reduction within the 10 implemented states. On April 25, 2024, the U.S. Environmental Protection Agency (EPA) unveiled its final rule to regulate greenhouse gas (GHG) emissions from power plants under Section 111 of the Clean Air Act. The updated rule mandates that coal-fired baseload units achieve 90% carbon capture and storage (CCS) by 2032. It also provides an option for plants scheduled for retirement by 2039 to co-fire up to 40% natural gas as a transitional measure to reduce emissions.

Non-CAISO WECC Demand Forecast

After years of relatively stagnant demand nationwide, recent additions of loads—such as data centers, manufacturing facilities, and electrification initiatives—have caused load forecast projections to surge. According to regional outlooks, the non-CAISO WECC region is anticipated to experience a compound annual growth rate (CAGR) of 1.8% from 2024 to 2030. Recent Integrated Resource Plans (IRPs) from utilities across the region, including Nevada Energy, Arizona Public Service, show higher-than-usual load growth expectations, largely due to significant new load additions expected to come online in the coming years.

Figure 3.7 - Non-CAISO WECC Capacity Retirement (GW)



Source: Siemens PTI

Forward Influence of the IRA

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

As of November 2024, the future of some provisions of the IRA remains uncertain under the new administration. While a repeal of the IRA is unlikely as that would require congressional approval, the Trump administration could slow the payment of grants and loans or rescind or modify regulations and guidance issued to date on how to implement provisions of the IRA. This action would make it difficult for companies and individuals to plan with certainty with respect to claiming tax credits for investments in new renewable and non-emitting technologies including EVs and offshore wind. A US policy movement away from federal climate initiatives could also enhance China's global dominance in clean energy industries such as solar panels and EVs, while potential new import tariffs could hinder the deployment of energy generation and other technologies supported by the IRA.

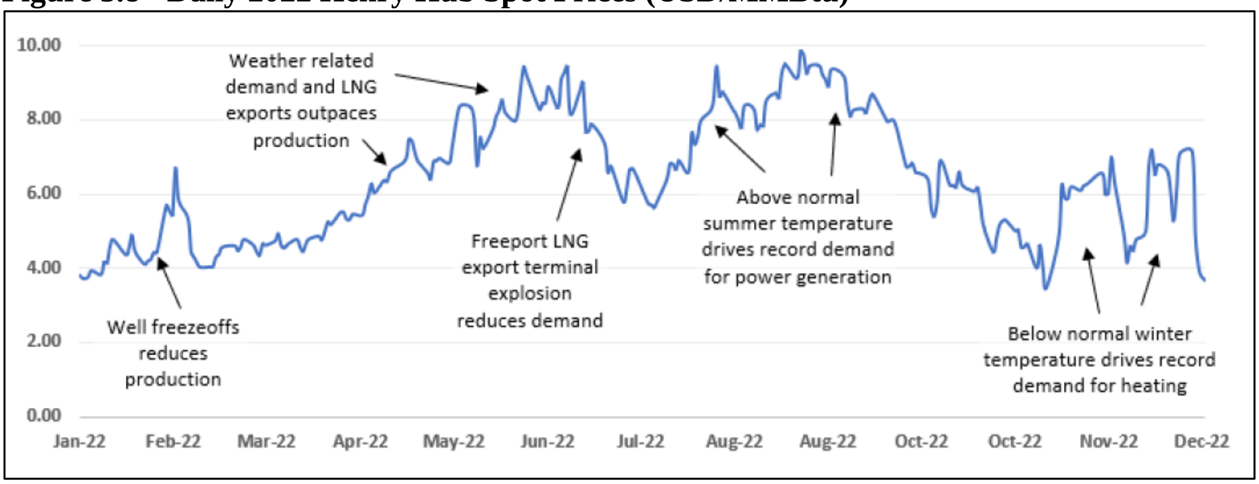
Natural Gas Prices

2022 Summary

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

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

Figure 3.8 - Daily 2022 Henry Hub Spot Prices (USD/MMBtu)



Source: S&P Global, Siemens PTI

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

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

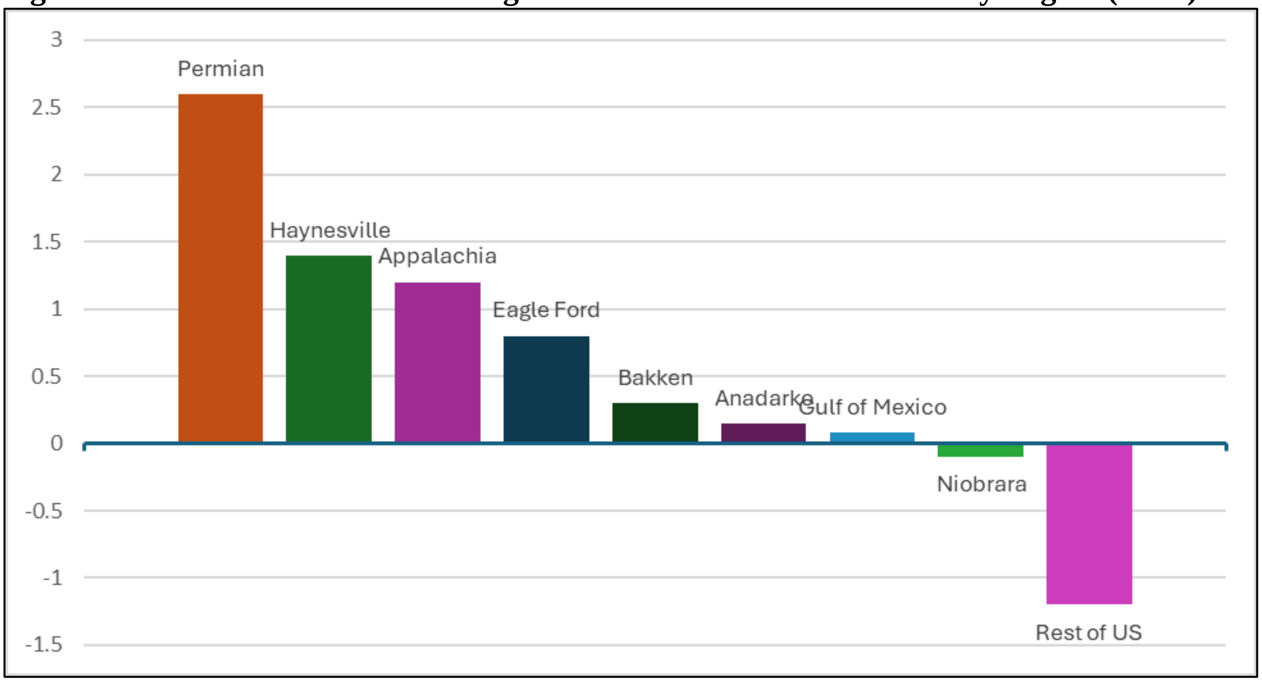
Production growth slowed over the second half of 2022 as inflation, labor, and materials shortages, and service sector constraints continued to impact producers, keeping overall domestic production hovering around 100 Bcf/d. Natural gas delivery in the US is complex due to the number of supply sources and pipelines that transport gas to various hubs around the country. As such prices at Henry Hub do impact prices in the West as the same source that supplies the gulf coast region can also supply the Western states.

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

2023 Summary

In 2023, U.S. natural gas prices saw a significant drop compared to the previous year, with the benchmark Henry Hub price averaging $2.57 per million British thermal units (MMBtu), a steep 62% decline from 2022. This price decline was largely driven by record-high production levels, which reached an average of 104 billion cubic feet per day (Bcf/d), 4% higher than the previous year. This production increase was particularly notable in key regions like the Permian, Haynesville, and Appalachia, where technological advancements and strong oil prices supported higher outputs.

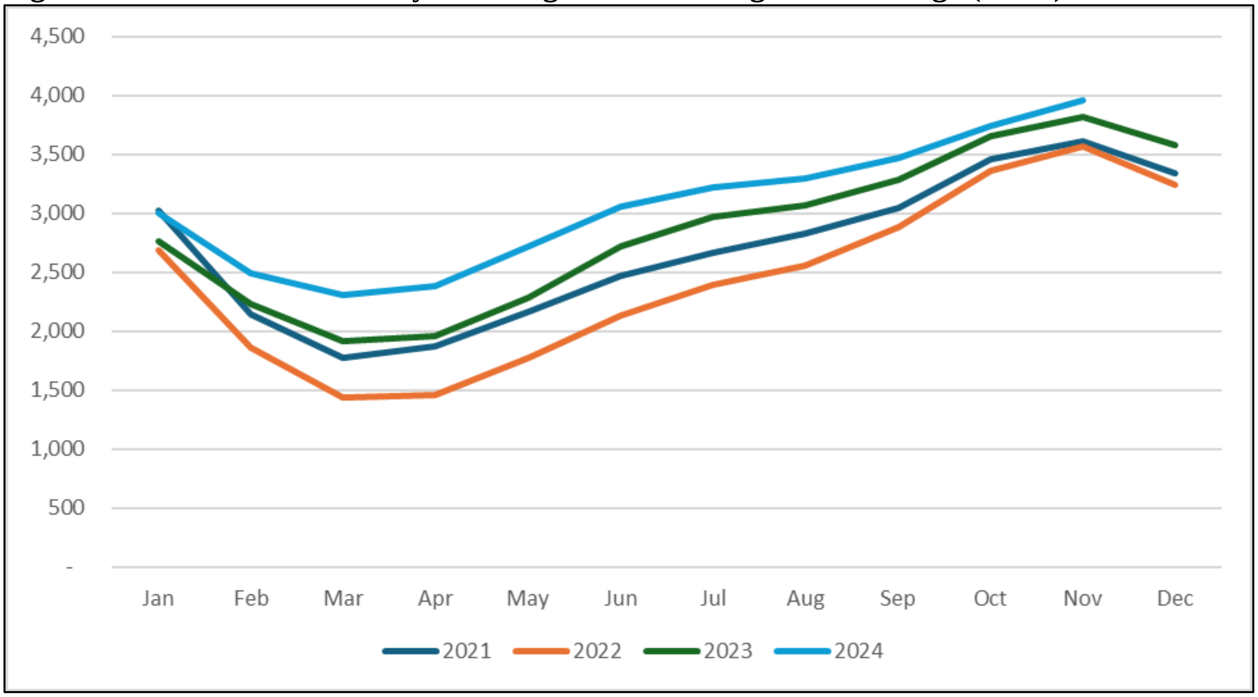
Figure 3.9 – Annual 2022-2023 Change in US Natural Gas Production by Region (bcf/d)



Source: EIA, Siemens PTI

Weather played a critical role in shaping the market. Warmer-than-average winter temperatures in January and February significantly reduced demand for natural gas in residential and commercial heating, particularly in the Midwest and Northeast, where natural gas is a primary heating source for most households. These mild conditions led to the lowest winter consumption levels in seven years and kept storage inventories above the five-year average for much of the year, further pressuring prices downward.

Figure 3.10 – Lower 48 Weekly Working Gas in Underground Storage (Bcf/d)



Source: EIA, Siemens PTI

On the West Coast, natural gas prices were influenced by unique regional factors. Severe winter storms early in the year disrupted supply chains and increased demand for heating in California and surrounding areas, creating temporary price spikes in localized markets. However, as weather conditions stabilized and milder temperatures returned, these pressures eased, and West Coast prices aligned more closely with the broader national trend of declining natural gas costs.

While domestic demand for natural gas remained relatively flat overall, there were notable increases in liquefied natural gas (LNG) exports, which rose by 12%, and pipeline exports, which increased by 9%. These exports helped offset some of the impact of reduced residential and commercial consumption. Despite this, the overall supply-demand balance remained tilted toward oversupply, with storage levels high and production continuing at record rates.

Adding to the dynamics was the gradual recovery of the Freeport LNG facility, which had been offline due to an outage in 2022 and returned to full operation in 2023. While this increased export capacity, it did not significantly alter the broader market trajectory, as domestic production remained the dominant factor. Prices remained under $3.00/MMBtu for most of the year, with May marking the lowest monthly average at $2.19/MMBtu, illustrating how robust supply and subdued demand combined to create one of the least volatile years for natural gas in recent history.

2024 Summary

In 2024, U.S. natural gas prices remained relatively low, with the Henry Hub averaging under $3.00 per MMBtu through November. Production levels, while slightly reduced compared to the previous year, remained robust at an average of 103.3 Bcf/d according to EIA. This marked the first annual production decline since 2020, driven by lower drilling activity as a result of subdued spot prices. Despite this, overall supply continued to outpace domestic demand, keeping inventories above the five-year average.

In the Permian Basin of western Texas and southeastern New Mexico, natural gas production, primarily as associated gas from oil wells, increased this year alongside rising oil production driven by oil prices, with expanding pipeline takeaway capacity, such as the Matterhorn pipeline, continuing to support higher production levels despite some volatility caused by periodic pipeline maintenance affecting Permian supply

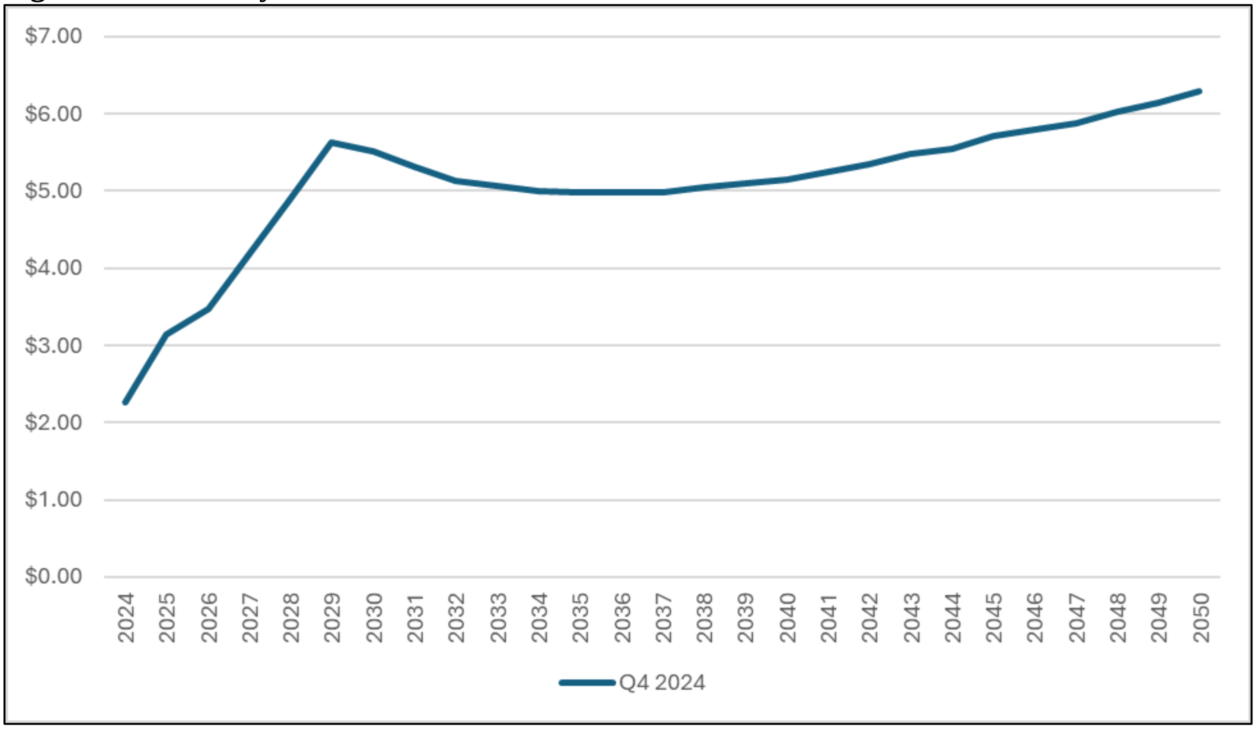
On the demand side, residential and commercial consumption increased due to a colder winter compared to 2023, reversing the trend of reduced heating needs observed in the prior year. LNG exports reached a record 12.1 Bcf/d as global demand for U.S. natural gas grew, particularly in Europe, where efforts to diversify energy sources remained a priority. However, higher exports were offset by stable industrial demand and moderate consumption for power generation, resulting in a balanced domestic market. Regional pricing saw temporary variations, particularly in the West, where localized weather events, including early-season storms, increased heating demand briefly. Despite these regional factors, the national market reflected a stable supply-demand balance with minimal volatility. This relative stability was further supported by the continued high storage levels, maintaining downward pressure on prices throughout the year.

2025-2032 Forward View

As we consider the 2025 to 2030 timeframe, our fundamental forecast for natural gas spot prices at Henry Hub indicates a steady upward trend, with prices expected to average in the mid-$4/MMBtu range in real terms by 2027. Total natural gas demand is projected to reach 122 Bcf/d by 2029, a 13% increase from 2023 levels, driven primarily by rising LNG exports and pipeline deliveries to Mexico. LNG exports are anticipated to double by 2027, as several terminals reach final investment decisions and expand capacity. Similarly, pipeline exports to Mexico are expected to grow significantly, fueled by increased demand for power generation and industrial use.

To meet this growing demand, U.S. natural gas production is expected to expand significantly, particularly from low-cost basins such as the Permian, Eagle Ford, and Haynesville. These regions are well-positioned to serve both domestic and export markets, benefiting from their proximity to demand centers and the development of new takeaway capacity through ongoing pipeline expansion projects. While the market may experience tightness through the middle of the decade due to accelerating LNG export growth, the combination of increased production and strategic infrastructure investments is expected to stabilize supply and support a balanced market by 2032.

Figure 3.11 – Henry Hub Futures



Source: Siemens PTI, GPCM

Conclusion

In summary, the natural gas market is poised for significant growth through the 2025–2030 timeframe, driven by surging export demand and supported by robust production from key basins and expanding infrastructure. While domestic demand shifts modestly, the market's stability will hinge on the alignment of production growth with expanding export capacity. Despite periods of tightness mid-decade, strategic investments and rising supply will position the market for long-term equilibrium, with Henry Hub prices reflecting this balance.

PacifiCorp's Multi-State Process

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

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

In December 2019, PacifiCorp filed the most recent inter-jurisdictional cost-allocation methodology, known as the 2020 PacifiCorp Inter-jurisdictional Allocation Protocol (2020 Protocol). Under the 2020 Protocol, five of PacifiCorp's six retail states would continue sharing all system resources, while Washington, which had previously only recognized resources in PacifiCorp's west Balancing Authority Area, would share in all system transmission and non-emitting resources. Signatories to the 2020 Protocol had been discussing the development of a future allocation methodology that would address all states' energy policy, while maintaining the benefits of PacifiCorp's system. In 2024, PacifiCorp determined that a negotiated agreement was unlikely given the differences in state energy policies and data limitations for parties to compare alternatives. PacifiCorp will file a new allocation methodology for approval by all six state commissions and implementation in 2026. PacifiCorp's guiding principles in the development of the new allocation methodology will continue to be:

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

Environmental Regulation

The upcoming administration change featuring Republican control of the House, Senate, and presidency, sets the stage for significant shifts in federal energy policy that could influence PacifiCorp's portfolio selection process used in the development of future IRPs. PacifiCorp recognizes the potential for new legislative and regulatory priorities to impact the energy sector and resource planning. The company actively monitors federal legislative and regulatory developments and participates in rulemaking processes by submitting comments, engaging in hearings, and providing policy assessments to ensure alignment with evolving requirements.

Suggested upcoming legislative priorities under the new administration include changes to the Inflation Reduction Act and a reconciliation bill with energy as a focal point that could directly impact PacifiCorp's existing and potential generation portfolio.

Federal Policy Update

National Electric Vehicle Infrastructure Formula Program

- $5 billion FY 2022-2026

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

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

Section 11401 Grants for Charging and Fueling Infrastructure

- $2.5 billion for FY 2022 – 2026.

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

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

The Inflation Reduction Act of 2022 (IRA) is a comprehensive set of clean energy legislation signed into law in August 2022 by President Biden. Substantive details of how the legislation will be implemented 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:

- The bill directs $437b in spending towards climate and healthcare investments with over $300b dedicated to deficit reduction.
- The bill extends existing and creates new energy investment and production tax credits and institutes a new technology-neutral zero emission generation tax credit in 2025, supplanting the extended generation-specific credits. Eligibility expires upon meeting economy-wide emissions reduction targets. The bill also establishes a new 15% corporate minimum book tax and a new 1% excise tax on corporate stock buybacks.
- Key Energy Provisions:
    - Extends wind, geothermal, and solar investment and production tax credits at full value through December 31, 2024. Solar projects are newly eligible to apply the production tax credit to energy generated. Additional 10% bonus credits each are available for both locating projects in communities with retired coal operations and

meeting certain domestic content requirements; achieving full credit value is also conditioned on meeting wage and apprenticeship requirements.
  - Establishes new tax credits for clean hydrogen, microgrids, electric vehicle purchases, existing nuclear generation, and the domestic manufacture of solar, wind, and battery components. Value and eligibility for existing carbon capture and sequestration credits are also enhanced and expanded.
  - Institutes a new technology-neutral, zero emission generation tax credit in 2025, supplanting the extended technology-specific credits. The technology-neutral credits phase down upon meeting economy-wide emissions reduction targets.

In the 2025 IRP, resources in designated areas are assumed to receive the 10% Energy Community bonus, resulting in a 110% PTC (wind, solar, other energy resources) or 40% ITC (energy storage and peaking resources)

New Credits and Considerations for Customer Resources–Inflation Reduction Act

Beginning January 1, 2023, the Clean Vehicle Credit (CVC) provisions remove manufacturer sales caps, expand the scope of eligible vehicles to include both EVs and FCEVs, and require a traction battery that has at least seven kilowatt-hours (kWh). An available tax credit under the CVC may be limited by the vehicle's MSRP and the buyer's modified adjusted gross income
Once the Treasury Department issues the critical mineral and battery component guidance, vehicles that meet the critical mineral requirements are eligible for $3,750 tax credit, and vehicles that meet the battery component requirements are eligible for a $3,750 tax credit. Vehicles meeting both the critical mineral and the battery component requirements are eligible for a total tax credit of $7,500.

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

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

New Source Performance Standards for Carbon Emissions 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 April 2024, the EPA finalized 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 (Clean Air Act Section 111(d) rule).

For new combustion turbines, the final rule establishes three subcategories based on operating intensity as measured by capacity factor.

1. Base load turbines (operating above 40% of maximum annual capacity factor) must initially meet a standard reflective of an efficient combined cycle design and also achieve 90% carbon capture by January 1, 2032.
2. Intermediate load turbines (operating between 20% and 40% of capacity factor) must meet a standard reflective of an efficient simple cycle design.
3. Low load turbines (operating below 20% capacity factor) must meet a standard based on using low-emitting fuels.

For existing coal-fired electric generating units (EGUs), the final rule subcategorizes plants based on the units intended operational timeline.

1. Long-term units (operating beyond January 1, 2039) must meet emission limits based on 90% carbon capture and storage (CCS) by January 1, 2032.
2. Medium-term units (retiring by January 1, 2039) must meet limits by January 1, 2030, using 40% natural gas co-firing.
3. Near-term units (closing before January 1, 2032) have no emission reduction obligations.

For existing gas- or oil-fueled steam units, the final rule subcategories units based on capacity factor.

1. Base load units (annual capacity factor greater than or equal to 45%) must maintain routine operations and maintenance, with no increase in emission rate (1,400 lb/MWh)
2. Intermediate load units (annual capacity factor between 8% and 45%) must maintain routine operations and maintenance, with no increase in emission rate (1,600 lb/MWh)
3. Low load units (annual capacity factor less than 8%) must meet a standard based on using low-emitting fuels.

States are required to submit implementation plans within two years of the rule's publication. These plans must show meaningful engagement with stakeholders, including affected communities and reliability authorities. States also have flexibility to consider factors like Remaining Useful Life, allow for emissions trading and averaging, and provide one-year compliance extensions for delays beyond an operator's control.

The rule has been challenged by multiple parties and is currently awaiting a decision from the D.C. Circuit Court of Appeals.

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

In 2008, the Internal Revenue Service issued a tax credit for carbon oxide sequestration under section 45Q to incentivize carbon capture and sequestration (CCS) investments. The tax credit is computed per metric ton (tonne) of qualified carbon oxide captured and sequestered.[7] Carbon oxide can either be permanently disposed of in secure geological storage or the carbon oxide can be utilized – typically as a tertiary injectant in enhanced oil recovery (EOR).

The Bipartisan Budget Act of 2018 reformed 45Q for carbon capture equipment that is placed in service on or after February 9, 2018, increasing the credit amount from $10/tonne to $35/tonne for utilization and from $20/tonne to $50/tonne for storage.[8] This Act also removed the limit on the amount of tax credits that could be awarded for CCS, and, instead, requires a minimum amount of carbon oxide to be capture annually (500,000 tonnes per year for an electric generating facility) and is available for 12 years from the date the carbon capture equipment is originally placed into service. The Consolidated Appropriations Act of 2021 extended the date construction must begin to receive the tax credits by two years, from January 1, 2024 to January 1, 2026.

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

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

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

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

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

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 NOx, 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, and granted a stay on the federal implementation plan on June 27, 2024.

Particulate Matter NAAQS

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

In November of 2020, the EPA proposed to redesignate the Salt Lake City and Provo $PM_{2.5}$ nonattainment areas to attainment. EPA received adverse comments on the proposed re-designation. EPA and the Utah Division of Air Quality working to address the comments. Re-designation to attainment would have no effect on current emissions and operating limits for the Lake Side and Gadsby facilities.

Regional Haze

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

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

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

Utah Regional Haze

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

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

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

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

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

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

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

On December 2, 2024, EPA issued a final partial approval and disapproval for Utah's regional haze state implementation plan for the second planning period without simultaneously issuing a federal implementation plan. Specifically, the EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management consultation components of the state plan. EPA's disapproval of Utah's long-term strategy is based in part on the rejection of SCR for Hunter and Huntington. In addition to disapproving the State's long-term strategy, the EPA disapproved Utah's reasonable progress goals and its consultation with Federal Land Managers, as compliance with these requirements is dependent on compliance with the long-term strategy provisions. There are no new compliance obligations for PacifiCorp at this time, as the disapprovals did not include a simultaneously proposed federal plan.

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

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

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

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

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

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

Wyodak – PacifiCorp and the state of Wyoming petitioned EPA's FIP requiring SCR at Wyodak in the Tenth Circuit. PacifiCorp and other parties successfully requested a stay of EPA's final rule relating to EPAs FIP pending court resolution of the petition. PacifiCorp subsequently submitted a request for reconsideration to EPA and engaged in a settlement process with EPA and Wyoming. The EPA, state of Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020. EPA published the Settlement Agreement in the Federal Register requesting public comment on January 4, 2021. PacifiCorp submitted formal comments to the EPA on March 5, 2021, in support of the Wyodak Settlement Agreement. 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 analyses was used by the state in its development of the SIP for the regional haze second planning period. Wyoming required emission limits and recognized planned unit retirements during the second planning period but did not require new controls to make reasonable progress. Wyoming submitted the state's regional haze SIP for the second planning period to the EPA before the August 15, 2022, statutory deadline. EPA notified Wyoming that its submittal was complete in August of 2022. PacifiCorp supports the state plan as it meets regional haze requirements.

The EPA issued a final partial approval and disapproval for Wyoming's regional haze state implementation plan for the second planning period. Specifically, the EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management consultation components of the state plan. EPA's disapproval of Wyoming's long-term strategy is based in part on the state's decision to forego a full four-factor analysis for units at Jim Bridger, Naughton, Dave Johnston, and Wyodak. In addition to disapproving the State's long-term strategy, the EPA disapproved Wyoming's reasonable progress goals and its consultation with Federal Land Managers, as compliance with these requirements is dependent on compliance with the long-term strategy provisions. There are no new compliance obligations for PacifiCorp at this time, as the disapprovals did not include a simultaneously proposed federal plan.

Colorado Regional Haze

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

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

Colorado Regional Haze 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

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

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

On April 25, 2024, EPA finalized revisions to the MATS rule following the agency's review of the 2020 Residual Risk and Technology Review. The final rule, effective July 8, 2024, tightens the standard for emissions of mercury from lignite-fired units and sets a more stringent standard for emissions of filterable particulate matter from all existing units. The rule also requires that continuous emissions monitoring be used to demonstrate compliance with the filterable particulate matter standard.

Coal Combustion Residuals

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

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

Following the March 2019 submittal of competing motions from environmental groups, EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule") in September 2020. The rule reclassified compacted-soil lined surface impoundments from "lined" to "unlined," established a deadline of April 11, 2021, by which all unlined surface impoundments must initiate closure, and revised the alternative closure provisions to grant facilities additional time to initiate closure in order to manage CCR and non-CCR waste streams either due to a lack of alternative capacity or due to a commitment to close the coal-fueled operating unit and complete closure of unlined impoundments by a date certain. The Part A rule also revised certain requirements regarding annual groundwater monitoring and corrective action reports and publicly accessible CCR internet sites. A provision in Part A allows demonstrations to be submitted to the EPA allowing for operation of unlined CCR ponds beyond the April 11, 2021, deadline for initiation of closure. PacifiCorp has submitted alternative closure demonstrations for the Naughton South Ash Pond and the Jim Bridger flue gas desulfurization (FGD) Pond 2. On October 12, 2023, Jim Bridger FGD Pond 2 ceased receiving waste and the newly constructed FGD Pond 3 was placed into service. EPA was notified on October 12, 2023, of PacifiCorp's withdrawal of its pending Part A alternative storage capacity demonstration request.

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

Separately, on August 10, 2017, the EPA issued proposed permitting guidance on how states' CCR permit programs should comply with the requirements of the final rule as authorized under the December 2016 Water Infrastructure Improvements for the Nation Act. To date, of the states in which PacifiCorp operates, only Wyoming has submitted an application to the EPA for approval of state permitting authority. EPA rejected Wyoming’s application due to concerns about the state’s ability to meet federal standards for the safe management of coal ash. The state of Utah adopted the federal final rule in September 2016, and issued the final permit for Huntington Power Plant CCR Landfill on March 21, 2023, and for Hunter Power Plant CCR Landfill on May 15, 2024. It is anticipated that the state of Utah will submit an application to EPA for approval of its CCR permit program but the timing of the submission remains uncertain.

The EPA finalized the legacy surface impoundments rule to extend federal CCR regulatory requirements to (1) inactive CCR surface impoundments at inactive utilities and (2) CCR management units (CCRMU) at active facilities, including CCR impoundments and landfills that closed prior to the effective date of the 2015 CCR Rule, inactive CCR landfills, and other areas where CCR is managed directly on the land. The final rule was published in the Federal Register on May 8, 2024, and became effective on November 8, 2024. The final rule includes exemptions and establishes new categories where regulation is deferred for applicable units, including CCRMU containing less than 1,000 tons of CCR, CCRMU located beneath critical infrastructure or large buildings or structures vital to the continuation of current site activities, and CCRMU that were closed prior to the effective date of the new rule. Affected facilities must conduct a facility evaluation and report to determine the presence of CCRMUs and/or legacy surface impoundments. Because the facility evaluation and report requirement will determine the magnitude of compliance obligations, the relevant registrants cannot assess the full impacts of the rule at this time.

Water Quality Standards

Cooling Water Intake Structures

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

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

Because Dave Johnston utilizes once-through cooling with withdrawal rates greater than 125 million gallons per day, the facility has been required to conduct more rigorous PARs.

Effluent Limit Guidelines

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

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

On April 25, 2024, EPA finalized the Supplemental ELG and Standards for the Steam Electric Generating Point Source Category (2024 ELG Rule or Final Rule), which maintains the 2020 ELG Rule Cessation of Coal Subcategory and includes a new subcategory for units that will retire/repower by December 31, 2034. The 2024 ELG Rule also imposes a zero liquid discharge requirement at coal-based generating units for bottom ash transport water, flue gas desulfurization wastewater, and coal combustion residual leachate.

Most of the issues raised by the 2024 ELG Rule are already being addressed at PacifiCorp facilities through compliance with the CCR rule and will not impose significant additional requirements on the facilities. The Dave Johnston plant submitted a notice of planned participation in October 2021 for subcategorization for units ceasing coal combustion by December 31, 2028. Participation in the subcategory allows continued management of bottom ash transport water using impoundments and discharge of the waste stream., The plant requested that the option to transfer to the installation and operation of a bottom ash recycle system be included in the new NPDES permit.

Renewable Generation Regulatory Framework

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

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

Tax Extender Legislation

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

State Policy Update

California

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

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

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

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

Idaho

In 2007, Idaho released its State Energy Plan, focusing on developing of a broad range of power generation options, improving energy efficiency, diversifying the state's energy portfolio, and reducing dependency on fossil fuels. The plan outlined strategies for energy conservation, the development of renewable energy sources, and improvements to transmission infrastructure within the state, aiming to balance growth with environmental stewardship and promote both economic development and sustainable energy practices.

In 2012, Idaho updated its 2007 plan to address new energy challenges and opportunities, emphasizing five core objectives: 1) a secure and stable energy system for Idaho’s citizens and businesses, 2) maintaining Idaho’s low-cost energy supply, 3) protecting public health and conserving natural resources, 4) promoting economic growth, job creation, and rural economic development, and 5) ensuring Idaho’s energy policy can adapt to changing circumstances.

In October of 2020, Governor Brad Little issued Executive Order 2020-17, continuing the role of the Office of Energy and Mineral Resources (OEMR) as the central coordinator for Idaho’s energy policy. The OEMR manages energy production, conservation, and policy alignment, ensuring the state's energy resources remain stable and cost-effective.

Oregon

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

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

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

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

In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. HB 2021 also expanded the capacity standard for Small Scale Renewables from 8% to 10%. PacifiCorp filed its first Clean Energy Plan (CEP) on May 31, 2023, which included possible pathways towards compliance with HB 2021 emissions reduction goals, inclusive of the Small-Scale Renewable (SSR) targets and with emphasis on community-based actions. As also directed by HB 2021, PacifiCorp convened a Community Benefits and Impacts Advisory Group in the fall of 2022. A Oregon Tribal Nations Clean Energy-specific engagement series was started in March of 2023 after six months of direct outreach. The engagement series was formatted by informed feedback from outreach to Oregon Tribal Nations members with whom PacifiCorp had an existing relationship and through new Tribal Nations relationship building

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

Washington

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

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

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

In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA) which requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025, be carbon neutral by January 1, 2030, and establishes a target of 100 percent of its electricity from renewable and non-emitting resources by 2045. PacifiCorp submitted its inaugural Clean Energy Implementation Plan on December 30, 2023, establishing a trajectory towards CETA compliance both for the current CEIP period, 2022 – 2025, and across the next two decades.

In 2021, Washington passed the Climate Commitment Act, which establishes a cap-and-invest program that was implemented through the regulatory rulemaking process and came into effect January 1, 2023. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utilities that are subject to CETA are allocated allowances within the cap-and-trade program at no cost, for emissions associated with Washington retail load. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.

In December 2022, Department of Ecology adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new light-duty vehicles (LDVs) be zero-emission vehicles (ZEVs) or PHEVs by 2035, ramping up from an initial requirement that 35% of new LDVs be ZEVs in 2026 this follows the CARB rulemaking. Furthermore, in December 2021, Washington adopted California's emission standards for HMDV via the Advanced Clean Truck Rules 2021. In 2022, Department of Ecology passed the Clean Fuel Standard law requires fuel suppliers to gradually reduce the carbon intensity of transportation fuels to 20% below 2017 levels by 2034. There are several ways for fuel suppliers to achieve these reductions, including:

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

Utah[9]

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

In April 2019, the Utah Legislature passed HB 411, Community Renewable Program, that allowed cities and municipalities in Utah to elect to participate on behalf of their residents. The Community Renewable Program is an opt-out program with the goal of being 100% net renewable by 2030. Customers within a participating community may opt out of the program and maintain existing

[9] Significant Utah legislative activity gathered interest in the 2025 IRP public input meeting series and stakeholder feedback. Regarding Utah SB-224, see Appendix M, stakeholder feedback form #13 (Emma Verhamme). Portfolio planning is currently not directly impacted by Utah SB-224, however variant and sensitivity studies may reflect this potential, such as the Low Cost Renewables case and the No Coal 2032 case. Additional discussion of Utah activity is addressed in Appendix M, stakeholder feedback form #37 (Utah Citizens Advocating Renewable Energy).

rates. The legislation prohibits cost shifting to non-participating customers. By the end of 2019, 23 Utah communities passed a resolution as required by the legislation to participate in the program. Program design efforts are underway and ongoing.

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

In March of 2024, the Utah Legislature passed SB 224, Energy Independence Amendments, that modifies the factors the Public Service Commission must consider when evaluating certain proposed energy resource decisions, establishes parameters for an affected electrical utility's recovery of costs associated with proven dispatchable generation resources located within the state, and encourages the commission to evaluate the purchase of excess proven dispatchable generation capacity.

In March of 2024, the Utah Legislature passed HB 191, Electrical Energy Amendments, that requires the Public Service Commission to act in accordance with the state energy policy and make certain determinations before authorizing the early retirement of an electrical generation facility.

Wyoming

On March 8, 2019, Wyoming Senate File 0159 (SF 159) was passed into law. SF 159 limits the recovery costs for the retirement of coal fired electric generation facilities, provides a process for the sale of an otherwise retiring coal fired electric generation facility, exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility; requires purchase of electricity generated from purchased retiring coal fired electric generation facility (as specified in final bill); and provides an effective date.

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

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

In March 2020, the Wyoming legislature passed House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards. HB 200 required the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The requirement applies to generation allocated to Wyoming customers. HB 200 requires each public utility to demonstrate in its IRP the steps taken to achieve the electricity generation standard established by the Commission and will allow rate recovery of costs incurred by a public utility that utilizes coal-fired generation with carbon capture technology installed. The Wyoming Public Service Commission implemented new administrative rules Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023 and include a low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. During the 2024 legislative session the Reliable and Dispatchable Low-Carbon Energy Standard statute was amended through SF 42, which extended the deadline for compliance with the Low-Carbon Energy Standards from July 1, 2030 to July 1, 2033.

In 2024, the Wyoming legislature passed SF 0023 Public Utilities-Energy Resource Procurement (SF 23) and SF 0024 Public Service Commission-Integrated Resource Plans (SF 24). SF 23 requires public utilities to conduct a solicitation process that is approved by the Wyoming Public Service Commission in order to acquire or construct a significant energy resource after July 1, 2024. A significant energy resource consists of 100 megawatts or more of new utility-owned generating capacity or utility-contracted generating capacity that has a dependable life or contract term of 10 or more years. SF 24 requires the Wyoming Public Service Commission to engage in long-range planning regarding public utility regulatory policy to facilitate the well-planned development and conservation of utility resources and requires the Commission to adopt rules providing a process for the review and acknowledgement of an action plan within an 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 lb CO_2/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. In September 2018, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 925 lb CO_2/MWh.

The Washington Department of Commerce issued a proposal to lower the emission performance standard to 863 lb CO2/MWh in October 2024. However, Chehalis was purchased by PacifiCorp in 2008. The change in ownership is the act that triggered the applicability of the standard. Because the EPS was 1,100 lb GHG/MWh during the time of triggered applicability, that is the standard that Chehalis complies with. It isn't until Chehalis undergoes a change in ownership, upgrade, or new or renewed long-term financial commitment with anyone other than Bonneville Power Administration that applicability to the lowered standard would be triggered.

Renewable Portfolio Standards

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

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

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

Table 3.3 – State RPS Requirements

	California	Oregon	Washington	Utah
Legislation	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011) • Senate Bill 350 (2015) • Senate Bill 100 (2018)	• Senate Bill 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009) • House Bill 1547-B (2016)	• Initiative Measure No. 937 (2006) • SB 5400 (2013)	• Senate Bill 202 (2008)
Requirement or Goal	• 20% by December 31, 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 • 44% by December 31, 2024 • 52% by December 31, 2027 • 60% by December 31, 2030 and beyond • Planning target of 100% renewable and zero-carbon by 2045 * Based on the retail load for a three-year compliance period	• 5% by December 31, 2011 • 15% by December 31, 2015 • 20% by December 31, 2020 • 27% by December 31, 2025 • 35% by December 31, 2030 • 45% by December 31, 2035 • 50% by December 31, 2040 * Based on the retail load for that year	• 3% by January 1, 2012 • 9% by January 1, 2016 • 15% by January 1, 2020 and beyond * Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective) • Annual targets are based on the adjusted[10] retail sales for the calendar year 36 months before the target year

California

California originally established its RPS program with passage of SB 1078 in 2002. Several bills have since been passed into law to amend the program. In the 2011 First Extraordinary Special Session, the California Legislature passed SB 2 (1X) to increase California's RPS to 33 percent by 2020.[11] SB 2 (1X) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities. In October 2015, SB 350, the Clean Energy and Pollution Reduction Act,

[10] Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture storage and DSM.

[11] www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf

was signed into law.[12] SB 350 established a greenhouse gas reduction target of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 and expanded the state's renewables portfolio standard to 50 percent by 2030. In September 2018, the signing of SB 100, the Clean Energy Act of 2018, further expanded and accelerated the California RPS to 60 percent by 2030 and directed the state's agencies to plan for a longer-term goal of 100 percent of total retail sales of electricity in California to come from eligible renewable and zero-carbon resources by December 31, 2045.

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

Table 3.4 – California Compliance Period Requirements

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

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

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

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

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

[12] leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.[13]

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

Table 3.5 – California Balanced Portfolio Requirements

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

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

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

Oregon

In June of 2007, Oregon established a comprehensive renewable energy policy, including RPS, with the passage of SB 838, the Oregon Renewable Energy Act.[14] Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet a target of at least 25 percent renewable energy by 2025. In March 2016, the Legislature passed SB 1547,[15] also referred to as Oregon's Clean Electricity and

[13] A REC can be sold either "bundled" with the underlying energy or "unbundled" as a separate commodity from the energy itself into a separate REC trading market.
[14] www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf
[15] olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

Coal Transition Act. In addition to requiring Oregon to transition off coal by 2030, the new law doubled Oregon's RPS requirements, which are set at 27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040 and beyond. Other components of SB 1547 include:

- Development of a community solar program with at least 10 percent of the program capacity reserved for low-income customers.
- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state's investor-owned utilities must come from small-scale renewable projects under 20 megawatts.
- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state's investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[16]

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

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

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

Electricity generated by a hydroelectric facility is eligible if the facility is not located in any federally protected areas designated by the Pacific Northwest Electric Power and Conservation Planning Council as of July 23, 1999, or any area protected under the federal Wild and Scenic Rivers Act, P.L. 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or if the

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

electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995, and up to 50 average megawatts of electricity per year generated by a certified low-impact hydroelectric facility owned by an electric utility and up to 40 average megawatts of electricity per year generated by certified low-impact hydroelectric facilities not owned by electric utilities.

PacifiCorp files an annual RPS compliance report by June 1 of every year. In addition, ORS 469A.075 now aligns the filing of the Renewable Portfolio Implementation Plan (or RPIP) with the filing of the IRP. These compliance reports and implementation plans are available on PacifiCorp's website.[17]

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

Utah

In March 2008, Utah's governor signed Utah SB 202, the Energy Resource and Carbon Emission Reduction Initiative, later codified in Utah Code Title 54 Chapter 17.[18] This law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions and for sales avoided because of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

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

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

PacifiCorp filed its most recent progress report on December 29, 2023. This report showed that the company is positioned to meet its 20 percent target requirement of approximately 5.0 million megawatt-hours of renewable energy in 2025 from existing company-owned and contracted renewable energy sources.

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

In 2027, the legislation requires a commission report to the Utah Legislature, which may contain any recommendation for penalties or other action for failure to meet the 2025 target. The legislation requires that any recommendation for a penalty must provide that the penalty funds be used for demand side management programs for the customers of the utility paying the penalty.

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[19] The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

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

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the Washington Utilities and Transportation Commission (WUTC) demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[20]

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

REC Management Practices

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

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

corporate sustainability goals. An expansion of this program is currently under development to be offered under a new tariff in Utah, Idaho and Wyoming.

Clean Energy Standards

Washington

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

Oregon

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

California

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

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

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

In 2022, California passed Senate Bill 1158. This bill requires the State Energy Resources Conservation and Development Commission to adopt guidelines for the reporting and disclosure of electricity sources by the hour. The bill includes hourly power source reporting as a new set of reporting requirements at the Energy Commission and allows for the commission to modify those requirements for small entities with under 60,000 customers in California, like Pacific Power. The Energy Commission issued proposed rules October 1, 2024, that would exempt the company from the hourly reporting requirement. The Energy Commission will likely adopt a final rule in early 2025.

Wyoming

In July 2020, House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards went into effect requiring the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The Wyoming Public Service Commission implemented rules for Low-Carbon Energy Portfolio Standards that went into effect in January 2022 requiring public utilities to file an initial plan to establish intermediate standards and requirements no later than March 31, 2022. A final plan must be filed by March 31, 2023 and include a final low-carbon energy portfolio standard of no less than 20 percent unless it is not economically or technically feasible. The Company requested an extension and filed the final plan on March 29, 2024 that included a proposal to: conduct additional technical and economic analyses for an Allam Fetvedt Cycle Project at either the Dave Johnston or Wyodak facilities by conducting a pre-FEED study in conjunction with SK and 8 Rivers; conduct additional technical and economic analyses by conducting a front-end engineering and design (FEED) study at the Jim Bridger facility; and no determination of a low-carbon portfolio standard at this time since CCUS continues to be evaluated for its technical and economic feasibility. The Commission approved the Company's final plan in public deliberations held on September 19, 2024. The statute also allows electric utilities to implement a surcharge not to exceed 2% of customer bills to recover costs to comply with the standard.

Transportation Electrification

The electric transportation market continues to strengthen since 2022. Overall, light duty battery electric vehicle sales have grown since 2022 resulting in a market share of about 9% in the United States[21]. PacifiCorp states, especially west coast states continue to outpace the US market share percentage, California is number one, with Oregon and Washington close behind[22]. By 2030 EVs (LDV) are expected to reach 7.7 million or 46% of sales[23]. EV sales still comprise a small portion of overall sales, however this will shift as medium-duty/heavy-duty (MD/HD) customers continue to expand. PacifiCorp also hosts major interstates and traffic corridors that will see continued electrification through policies discussed above. Furthermore, many businesses are moving to electrify their fleets from port authorities, transit agencies, etc. which will increase load over time.

This rapidly evolving market represents a potential driver of future load growth and those impacts managed proactively, provide an opportunity to increase the efficiency of the electrical system and provide benefits for all PacifiCorp customers. In addition, increased adoption of electric transportation has the ability to improve air quality, reduce noise pollution, reduce greenhouse gas emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low- and moderate-income populations.

Current EV adoption numbers indicate that there is still an enormous opportunity for growth in the EV market. To develop a prospective forecast of EV adoption, PacifiCorp developed a model to assess trends for light duty vehicles (LDVs) and medium-duty and heavy-duty vehicles (MD/HDVs). To inform a future vehicle adoption curve, the Company reviewed three national EV

[21] October 2024 auto sales volume to hold steady in the US | S&P Global
[22] Electric vehicle market and policy developments in U.S. states, 2023 - International Council on Clean Transportation
[23] Electric Vehicle Sales and the Charging Infrastructure Required Through 2035

forecasts, each representing varying degrees of aggressiveness. While these forecasts represent national trends, the adoption curves themselves are quite different and can be adjusted to reflect state-specific parameters such as current market conditions, light duty truck saturation, and EV policies adopted in the state. PacifiCorp monitors vehicle adoption in each state on an annual basis and adjusts forecasts accordingly as new data is made available.

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

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

In Utah, PacifiCorp is implementing the $50 million Electric Vehicle Infrastructure Program that has four core components: Company-owned public fast chargers, customer incentives, innovative projects, and outreach and education efforts. In June 2024, the first four locations with Company-owned public direct current fast chargers (DCFC) became operational. It is anticipated that there will be roughly 20 locations with an estimated 100 DCFC stations throughout Utah by the end of the program. As of the end of 2023, PacifiCorp had supported installation of over 4,800 EV ports throughout the territory.

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

Hydroelectric Relicensing

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

The value of relicensing hydroelectric facilities is continued availability of energy, capacity, and ancillary services associated with hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility because they can be called upon to meet peak customer demands almost instantaneously and back up intermittent renewable resources such as wind and solar with carbon-free generation. In addition to operational flexibility, hydroelectric generation

[24] California Electric Vehicle Infrastructure Line Extensions (pacificpower.net)

does not have the emissions concerns of thermal generation. Hydroelectric projects can also often provide important ancillary services, such as spinning reserve and voltage support, to enhance the reliability of the transmission system.

As of December 31, 2024, PacifiCorp has 15 FERC licensed hydroelectric projects. Each license may contain a single or multiple hydro developments (e.g., dams and powerhouses). PacifiCorp is currently seeking new licenses for the Cutler (30 MW) and Ashton (7.85 MW) hydroelectric projects. A new license for Cutler is expected in 2025, and a new license for Ashton in 2027. The next project to undergo the FERC relicensing process is the Bear River hydroelectric project (77 MW). That project's FERC license expires in 2033.

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

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

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2023, PacifiCorp had incurred approximately $33 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work-in-progress on

PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Cutler, Ashton and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, water quality, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. Much of these relicensing implementation and settlement costs relate to PacifiCorp's two largest hydroelectric projects: Lewis River and North Umpqua.

Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Chapter 7.

PacifiCorp's Approach to Hydroelectric Relicensing

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

Rate Design

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

Residential Rate Design

Residential rates in Utah are comprised of a customer charge and energy charges. The customer charge is a monthly charge that provides limited recovery of customer-related costs incurred to serve customers regardless of usage and is broken into separate charges for residential customers who live in single family and multi-family dwellings All other remaining costs are recovered through volumetric- based energy charges. Energy charges for residential customers are designed with an inclining-tier rate structure so high usage during a billing month is charged a higher rate. Additionally, energy charges are differentiated by season with higher rates in the summer when the costs to serve are higher. Residential customers also have an option for time-of-day rates. Time-of-day rates have a surcharge for usage during the on-peak periods and a credit for usage during the off-peak periods. This rate structure provides an additional price signal to encourage customers to use less energy during the daily on-peak periods when energy costs are higher. As of December 2023, , less than one percent of customers have opted to participate in the time-of-day rate option.

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

Commercial and Industrial Rate Design

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

Irrigation Rate Design

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

Electricity Market Development Update

PacifiCorp and the CAISO launched the Western Energy Imbalance Market (WEIM) on November 1, 2014. The WEIM is a voluntary market and the first western energy market outside of California. NV Energy (NVE) began participating in December 2015, Arizona Public Service

(APS) and Puget Sound Energy (PSE) began participating in October 2016, and Portland General Electric (PGE) began participating in October 2017. Idaho Power and Powerex began participating in April 2018, and the Balancing Authority of Northern California (BANC)[1] began participating in April 2019. Seattle City Light (SCL) and Salt River Project (SRP) began participating in April 2020, and 2021 saw the addition of NorthWestern Energy, Los Angeles Department of Water & Power (LADWP), Public Service Company of New Mexico (PNM), and Turlock Irrigation District (TID). Avista Utilities, Tucson Electric Power (TEP), Tacoma Power and Bonneville Power Administration (BPA) officially became a participant in the EIM in 2022. El Paso Electric (EPE), Western Area Power Administration Desert Southwest (WAPA DSW) and Avangrid (AVR) entered in April 2023. In 2026, Black Hills Montana and Berkshire Hathaway Energy Montana (BHE Montana) have planned entry into the WEIM.

The WEIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Texas, New Mexico, Utah, Washington, Wyoming, and British Columbia which make up almost eighty percent of the Western Energy Coordinating Council (WECC) load and will expand to include Montana in 2026. PacifiCorp continues to work with the CAISO, existing and prospective WEIM entities, and stakeholders to enhance market functionality and support market growth.

Figure 3.12 – Western Energy Imbalance Market Expansion

The WEIM has produced approximately $5.85B in monetary benefits since inception for participating utilities, quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every fifteen and five minutes within and across the WEIM footprint based on the most economical solution; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexible reserves in all WEIM balancing authority areas which reduces cost by aggregating load, wind, and solar variability and forecast errors of the WEIM footprint.

A significant contributor to WEIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations that exist in states with a price on carbon (i.e., California and Washington). Generally, transfer quantities are based on transmission and interchange rights between participating balancing authority areas.

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

Over the duration of 2022, the CAISO held a robust stakeholder process to develop the market design of the Extended Day-Ahead Market (EDAM). With stakeholder feedback, the final EDAM proposal was released in early December 2022. On December 8th, PacifiCorp announced that it intends to join EDAM. The final EDAM design was approved by the CAISO Board of Governors and WEIM Governing Body in early February 2023, and received FERC approval on December 28, 2023. EDAM is scheduled to go live on May 1, 2026, and to date, PacifiCorp and Portland General Electric have signed their EDAM implementation agreements.

The Southwest Power Pool (SPP) has also been developing a day-ahead market offering, called Markets+. Markets+ introduces a potential risk to WEIM benefits through a shrinking WEIM footprint as stakeholders who want to participate in Markets+ would need to exit WEIM. In addition to a smaller WEIM footprint, day-ahead markets with different design elements and requirements for participation exacerbate the seams issue which already exist throughout the west. SPP and stakeholders filed their tariff with FERC on March 29, 2024 and received a deficiency letter on July 31, 2024 that SPP is currently working through to remedy FERC’s clarification and additional information request due at the end of November 2024. SPP does not believe the SPP Markets+ timeline will be impacted for their projected spring 2027 go-live target and stakeholders must be vigilant to ensure the markets work as cohesively as possible.

Recent Resource Procurement Activities

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

Table 3.6 – PacifiCorp's Requests for Proposal Activity

RFP	RFP Objective	Status	Issued	Completed
Renewable energy credits (Purchase)	Excess system RECs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Oregon compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Washington compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Ongoing	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Ongoing	Based on specific need	Ongoing
2024 Utah Renewables Community RFP	Seeking resources consistent to the Community Clean Energy Act (Utah Code 54-17-901 to -909)	Ongoing	Expected November 2024	Expected October 2025
2025 All-Source RFP	Seeking resources consistent with the 2025 IRP's least cost resource portfolio	Ongoing	Expected 2025	Expected in Q4 2025

2022 All-Source RFP

On April 1, 2024, PacifiCorp published the company's 2023 Integrated Resource Plan Update. The 2023 IRP Update preferred portfolio demonstrated that with limited procurement of battery resources in the near-term, which can be achieved outside of a request for proposals process, there is material customer benefit to scaling down and delaying resource acquisition until after 2030. As such, the 2022 All-Source Request for Proposals was terminated. PacifiCorp's 2025 IRP will inform the next steps for incremental resource acquisition.

2024 Utah Renewables Community RFP

The 2024 Utah Renewable Communities' Request for Proposals for renewable energy resources (2024 URC RFP), is administered by the Community Renewable Energy Agency (Agency) on behalf of customers that participate in the Community Clean Energy Program (Program). The 2024 URC RFP is seeking cost-competitive bids for energy produced by wind, photovoltaic (PV) solar, geothermal, or hydroelectric resources and interconnecting with PacifiCorp's transmission system. The Agency is seeking to purchase energy from renewable resources pursuant to the Community Clean Energy Act (Act (Utah Code 54-17-901 to -909)) and in support of the Program created by the Act and the Utah Public Service Commission (Commission). The 2024 URC RFP is planned to be released in late November 2024.

2025 All-Source RFP

PacifiCorp will seek to file the 2025 All Source RFP (“2025AS RFP”) based on results identified in the 2025 IRP preferred portfolio. Further updates on the status and schedule of the 2025AS RFP will be provided as they become available.

Recent Resource Procurement/DSM Procurement

In 2023, PacifiCorp issued a Request for Proposals to re-procure program delivery services for the Home Energy Savings and Wattsmart Business energy efficiency programs in Washington and California. As a result of the re-procurement, new contracts for Washington and California were signed in 2024. For Washington specifically, PacifiCorp followed its Competitive Procurement Framework,[25] including seeking Washington DSM Advisory Group input and posting a notice on the Company website prior to releasing the Request for Proposals. In 2024, PacifiCorp issued a Request for Proposals to re-procure program delivery services for Wattsmart Business in Utah, Idaho and Wyoming, and contracting is underway.

In 2024, PacifiCorp also issued an RFP for energy efficiency implementation services for a commercial new construction program in its Utah service area. The procurement and subsequent contracting steps are still underway.

[25] 2022-2023 Biennial Conservation Plan, Appendix 6 (Docket UE-201830)
The current Competitive Procurement Framework for Washington Conservation and Efficiency Resources is available in Appendix 6 to the 2024-2025 Biennial Conservation Plan (Docket UE-230904).

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp's planned transmission projects help facilitate a transitioning resource portfolio and comply with reliability requirements, while providing sufficient flexibility necessary to ensure existing and future resources can meet customer demand cost effectively and reliably.
- Given the long lead time needed to site, permit, and construct new transmission lines, these projects need to be planned well in advance of resource additions.
- PacifiCorp's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and respond to commission and stakeholder requests for a robust evaluation process and clear criteria for evaluating transmission additions.
- The 2025 IRP preferred portfolio includes the following notable transmission upgrades:[1]
    - A series of upgrades to increase transfer capability between southern Utah and the Wasatch Front, projected to come online between 2026 and 2036.
    - New transmission from the Walla Walla substation near Walla Walla, Washington to the Wine Country substation near Sunnyside, Washington, projected to come online in 2031.
    - 120 miles of new transmission from the Fry substation near Albany, Oregon to a new substation in Deschutes County, Oregon, projected to come online in 2032.
    - New transmission including lines from the Fry substation near Albany, Oregon and from the Dixonville substation near Roseburg, Oregon, each connecting to a substation near Lebanon, Oregon, projected to come online in 2036.
    - A second 416-mile transmission line from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South 2), projected to come online in 2036.

- Further, the 2025 IRP preferred portfolio includes near-term transmission upgrades across PacifiCorp's transmission system including investment in infrastructure in Oregon, Utah, and Washington that will facilitate continued and long-term growth in new resources needed to serve PacifiCorp's customers.

Introduction

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

[1] Two significant transmission projects have been placed in-service since the 2023 IRP, and are therefore included in the 2025 IRP base modeling:

- The Energy Gateway South transmission line - a new 416-mile, high-voltage 500 –kilovolt (kV) transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This transmission line was placed in service in Q4-2024.
- The Energy Gateway West Subsegment D1 project - a new high-voltage 230-kilovolt transmission line and a rebuild of an existing 230 kV transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. These lines were placed in service in Q4-2024.

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

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

This chapter provides:

- An overview of PacifiCorp's regulatory requirements including recent updates to PacifiCorp's generation interconnection procedures.
- Support for PacifiCorp's plan to continue permitting the balance of Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of PacifiCorp's investments in recent short-term system improvements that have improved reliability, helped to maximize efficient use of the existing system, and enabled the company to defer the need to invest in larger-scale transmission infrastructure.

Regulatory Requirements

Open Access Transmission Tariff

Consistent with the requirements of its OATT, approved by the Federal Energy Regulatory Commission (FERC), PacifiCorp plans and builds its transmission system based on two customer-type agreements—network customer or point-to-point transmission service. For network customers, PacifiCorp uses ten-year load-and-resource (L&R) forecasts supplied by the customer, as well as network transmission service requests to facilitate development of transmission plans. Each year, PacifiCorp solicits L&R data from each of its network customers to determine future L&R requirements for all transmission network customers. The bulk of PacifiCorp's network customer needs comes from the company's Energy Supply Management (ESM) function, which supplies energy and capacity for PacifiCorp's retail customers. Other network customers include Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative (including Moon Lake Electric Association), Bonneville Power Administration (BPA), Basin Electric Power Cooperative, Tri-State Generation & Transmission, the United States Department of the Interior Bureau of Reclamation, and the Western Area Power Administration.

PacifiCorp uses its customers' L&R forecasts and best available information, including transmission service and generation interconnection requests, as factors to determine the need and timing for investments in the transmission system. If customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios or schedules for transmission system investments, as appropriate. In accordance with FERC guidelines, PacifiCorp is able to reserve transmission network capacity based on this data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required to deliver significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of L&R forecasts.[2] A 20-year planning horizon and ability to reserve transmission capacity to meet existing and forecasted need over that timeframe is more consistent with the time required to plan for and build large-scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

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

Reliability Standards

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

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

Generation Interconnection Study Methodology Changes

In 2022 PacifiCorp filed a request with FERC to modify its large generator interconnection procedure to allow PacifiCorp to study new standalone storage resources as not discharging during high generation of other resources in the region. The request was approved by FERC in March 2022 and the new assumptions were implemented into generation interconnection studies starting with Cluster 2. The new operating assumptions have allowed PacifiCorp to use more realistic study assumptions for storage resources which in some circumstances should alleviate the need for additional network upgrades to interconnect new resources.

In 2023 FERC released Order 2023 which required modifications of all transmission provider's including PacifiCorp's, generator interconnection procedures. Several notable changes were included in Order 2023. First, FERC required all transmission providers to move to a first ready, first serve cluster study process which PacifiCorp had already transitioned to in 2020. Second, FERC required all transmission providers to use a distribution factor analysis to assign cost responsibility to specific interconnection customer requests driving the need for network upgrades. This change to PacifiCorp's procedures will allow for projects sited in locations that have smaller impacts on the transmission system, avoiding cost responsibility for upgrades in the region that its project does not cause. Other aspects of the Order 2023 include requiring 100 percent of site control for proposed generating facilities with the initial application and substantial withdrawal penalties at the facilities study stage both of which should disincentivize speculative projects. PacifiCorp will implement a transition process in which existing interconnection requests that have not yet proceeded far enough in the study process will have the opportunity to be studied in a transition cluster study or be withdrawn. PacifiCorp's next application window for new generation interconnection requests will open in 2026.

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

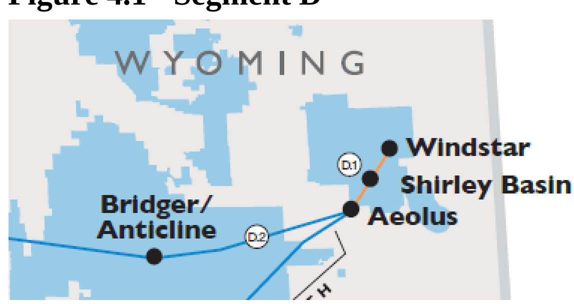
The Energy Gateway South transmission line is a new 416-mile, high-voltage 500-kV transmission line and associated infrastructure running from the Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The transmission line is currently under construction and scheduled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

Windstar-Populus (Gateway West – Segment D)

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

- D1—Recently placed in service, a single-circuit 230-kV line running approximately 59 miles between the existing Windstar and Aeolus substations while looping in and out of Shirley Basin substation in eastern Wyoming;

Figure 4.1 - Segment D



- D2—A single-circuit 500-kV line completed October 2020 and energized November 2020 and
- D3—A single-circuit 500-kV line running approximately 200 miles between the new Anticline substation and the Populus substation in southeast Idaho.

Populus-Hemingway (Gateway West - Segment E)

The Populus-to-Hemingway transmission project consists of two single-circuit 500-kV lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho.

While PacifiCorp is not requesting acknowledgement of a plan to construct these segments in this IRP, the company will continue to permit the projects specifically transmission segment between Midpoint-to-Hemingway portion of Segment E.

Figure 4.2 - Segment E

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

Plan to Continue Permitting – Gateway West

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

Boardman-Hemingway (Segment H)

Boardman-to-Hemingway(B2H) is an approximately 290-mile high-voltage 500-kV transmission line capable of coming online in 2027. PacifiCorp is continuing to coordinate with regional transmission providers and retail customers to evaluate options for this project.

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

Idaho Power's 2023 IRP identified the B2H as a preferred resource to meet its capacity needs, reflecting a need for the project in 2026 to avoid a deficit in load-serving capability in peak-load periods. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line to be in 2027 or beyond.

The BLM released its record of decision ROD for B2H on November 17, 2017. The ROD allows BLM to grant right-of-way to Idaho Power for the construction, operation, and maintenance of the

B2H Project on BLM-administered land. The BLM right-of-way grant was executed on January 9, 2018.

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

On September 27, 2022, Oregon's Energy Facility Siting Council approved the Oregon site certificate completing Oregon's permit actions that provide for the construction of the project across private lands in Oregon. Following this action an appeal was made to the Oregon Supreme court challenging the approval. On March 8, 2023, the court affirmed the site certificate which finalized the site certificate.

In January of 2022 Idaho Power, BPA and PacifiCorp agreed in a non-binding term sheet to negotiate Bonneville's exit of the project with Idaho Power acquiring Bonneville's share responsibility of the project. This will provide Idaho Power with a 45 percent share of the project and retain PacifiCorp's 55 percent share. Additional terms under negotiations include changes in transmission service between PacifiCorp and BPA; between BPA and Idaho Power, as well as the purchase and sale of certain assets between Idaho Power and PacifiCorp. The Boardman to Hemingway amended Permit Funding Agreement removing Bonneville and updating the agreement to capture additional pre-construction tasks was executed on March 23, 2023. The Joint Purchase and Sale agreement between Idaho Power and PacifiCorp provides Idaho Power with certain assets allowing service to BPA customers in southeast Idaho via the B2H line, and capacity from the Four Corners substation in New Mexico to the Populus substation in southern Idaho. Associated with the term sheet is the Hemingway project construction agreement, construction agreements for upgrades that provide PacifiCorp additional capacity across Idaho Power's transmission system and a construction agreement that provides PacifiCorp additional capacity to serve central Oregon loads. These agreements were all executed on March 23, 2023.

Idaho Power has applied for Certificates of Public Convenance and Necessity (CPCN) in Oregon and Idaho. Issuance of both certificates were received in June of 2023. PacifiCorp received a CPCN in Idaho in June 2023 and in Wyoming in August 2023.

The current project schedule includes projected completion in 2027.

At this time, PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Spanish Fork – Mercer 345-kV line

The 2025 preferred portfolio includes the construction of a new, approximately 50-mile, 345-kV transmission line between Spanish Fork Substation and Mercer substation in Utah, with an identified in-service date of 2036, based on projected interconnection requirements. Load-service and reliability requirements may bring this date forward, as could accelerated generator interconnection demand. PacifiCorp has begun the permitting process for this new transmission line and is currently targeting an in-service date of 2027 for the line.

Other Transmission System Improvements

The 2025 IRP preferred portfolio also includes near-term transmission upgrades across its transmission system. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources and increased reliability for its customers.

Energy Gateway Transmission Expansion Plan

Introduction

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

Background

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

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

Planning Initiatives

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

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

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

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

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

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

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

The NorthernGrid 2022-2023 Regional Transmission Plan identified the regional combination consisting of Gateway West (Segment D.3 and Segment E) and B2H as the most efficient and cost-effective set of projects for the NorthernGrid 10-year planning horizon. Gateway South was considered as an in-service project in all cases, including the selected regional combination.

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

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

Energy Gateway Configuration

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

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

These groups continually evaluate PacifiCorp's transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp's OASIS site for information and materials related to these public processes.[3]

Additionally, an extensive 18-month stakeholder process on Gateway West and Gateway South was conducted. This stakeholder process was conducted in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles, and was used to

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

establish need, assess benefits to the region, vet alternatives, and eliminate duplication of projects. Meeting materials and related reports can be found on PacifiCorp's Energy Gateway OASIS site.

Energy Gateway's Continued Evolution

The Energy Gateway Transmission Expansion Plan is the product of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since its announcement in May 2007, Energy Gateway's scope and scale have continued to evolve to meet the future needs of PacifiCorp customers and the requirements of mandatory transmission planning standards and criteria. Additionally, PacifiCorp has improved its ability to meet near-term customer needs through a limited number of smaller-scale investments that maximize efficient use of the current system and help defer, to some degree, the need for larger capital investments like Energy Gateway (see the following section titled "Efforts to Maximize Existing System Capability"). The IRP process, as compared to transmission planning, can result in frequent changes in the least-cost, least-risk resource plan driven by changes in the planning environment (i.e., market conditions, cost and performance of new resource technologies, etc.). Near-term fluctuations in the resource plan do not always support the longer-term development needs of transmission infrastructure, or the ability to invest in transmission assets in time to meet customer needs. Together, however, the IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers.

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

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

In 2010, PacifiCorp entered into memorandums of understanding (MOU) to explore potential joint-development opportunities with Idaho Power Company on its Boardman-to-Hemingway (B2H) project and with Portland General Electric Company (PGE) on its Cascade Crossing project. One of the key purposes of Energy Gateway is to better integrate PacifiCorp's east and west balancing authority areas, and Gateway Segment H from western Idaho into southern Oregon was originally proposed to satisfy this need. However, recognizing the potential mutual benefits and value for customers of jointly developing transmission, PacifiCorp has pursued these potential partnership opportunities as a potential lower-cost alternative.

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

In 2012, PacifiCorp determined that one new 230 kV line between the Windstar and Aeolus substations and a rebuild of the existing 230 kV line were feasible, and that the second new proposed 230 kV line and proposed 500 kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from PacifiCorp's ongoing focus on meeting customer needs, taking stakeholder feedback and land-use limitations into consideration, and finding the best balance between cost and risk for customers. In January 2012, PacifiCorp signed the B2H Permitting Agreement with Idaho Power Company and BPA that provides for PacifiCorp's participation through the permitting phase of the project. The B2H project was pursued as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). Idaho Power leads the permitting efforts on the B2H project, and PacifiCorp continues to support these activities under the conditions of the B2H Transmission Project Joint Permit Funding Agreement. The proposed line provides additional connectivity between PacifiCorp's west and east balancing authority areas and supports the full projected line rating for the Gateway projects at full build out. PacifiCorp plans to continue to support the project under the Permit Funding Agreement and will assess next steps post-permitting based on customer need and possible benefits.

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

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

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

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

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

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

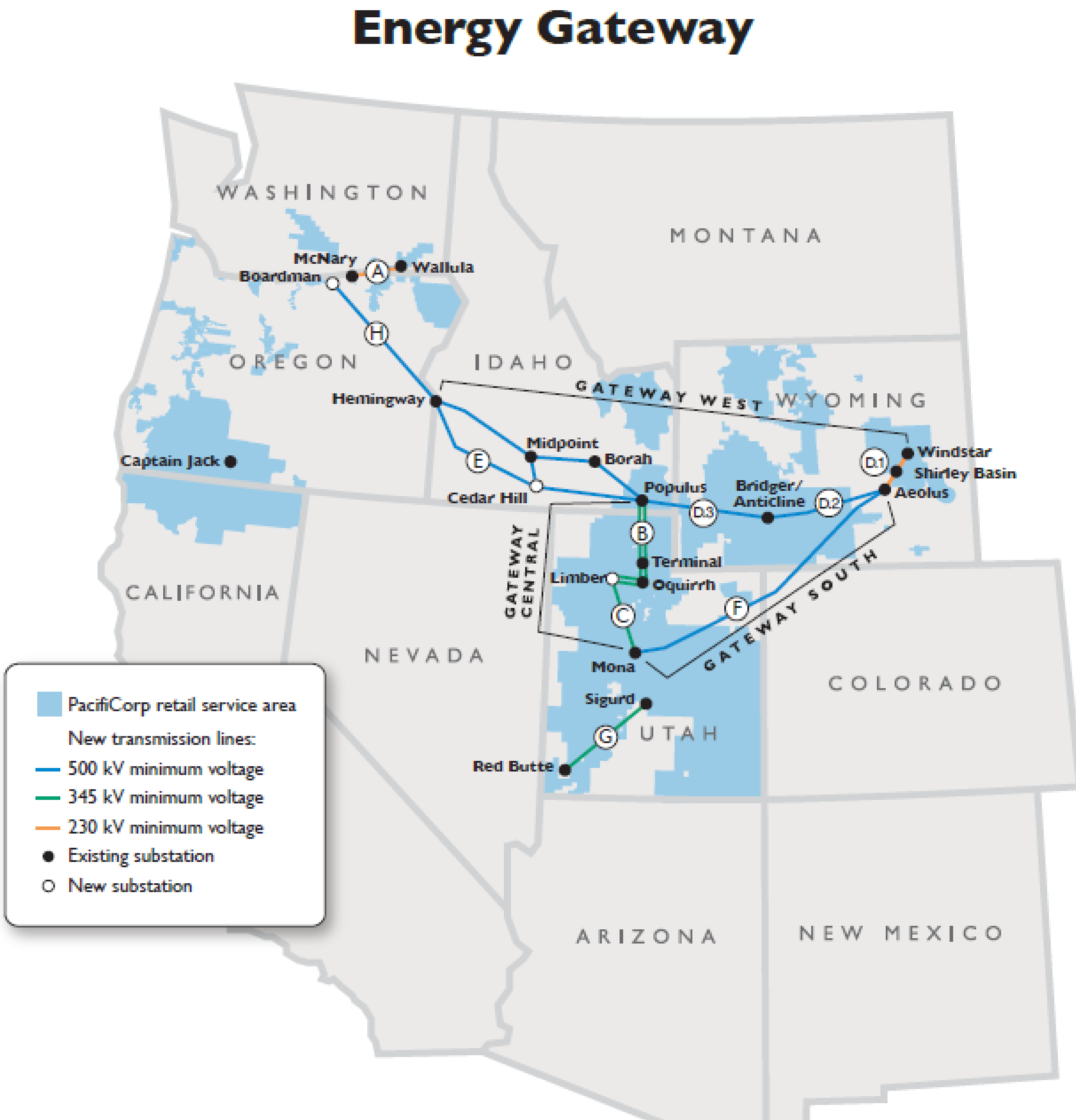
In October 2020, a portion of Gateway West Segment D1, the 230 kV line between Aeolus and Shirley Basin was also constructed and completed in 2020. The remaining portion of Gateway West, Segment D1, consisting of a new 230 kV line between Shirley Basin and Windstar substations and a rebuild of an existing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

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

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

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

Figure 4.3 – Energy Gateway Transmission Expansion Plan



This map is for general reference only and reflects current plans.
It may not reflect the final routes, construction sequence or exact line configuration.
PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Table 4.1 – Energy Gateway Transmission Expansion Plan

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: completed • Placed in-service: January 2019
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: completed • Placed in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: right-of-way acquisition underway • Scheduled in-service: 2024
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	59 mi	• Status: permitting underway • Scheduled in-service: December 2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: completed • Placed in-service: November 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in-service: 2034 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2036 earliest
(F) Aeolus-Mona	500 kV single circuit	416 mi	• Status: permitting underway • Scheduled in-service: December 2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: completed • Placed in-service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	290 mi	• Status: pre-construction activities in progress • Scheduled in-service: 2027

Efforts to Maximize Existing System Capability

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

System-wide, PacifiCorp has instituted more than 130 grid operating procedures and 20 remedial action schemes (RAS) to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the Energy Imbalance Market (EIM) since November 2014. As of April 2023, 22 participants have joined the EIM. By broadening the pool of lower-cost resources that can be accessed to balance load system requirements, enhances reliability and reduces costs across the entire EIM Area. In addition, the automated system can identify and use available transmission capacity to transfer the dispatched resources, enabling more efficient use of the available transmission system.

To secure further benefits from market-based resource dispatch, PacifiCorp announced in December 2022 that it expects to participate in the Extended Day-Ahead Market (EDAM) being developed by the California Independent System Operator (CAISO).[4] While the EIM makes full use of resource flexibility within the hour and will continue to do so, the EDAM will provide economic, reliability, and environmental benefits by optimizing the pool of resources that are made available to EIM in light of forecasted requirements for the entire market footprint over the following several days, well beyond the end of the current hour. This includes coordination of generator starts and shutdowns and the charging and discharging of energy storage resources.

Transmission System Improvements Placed In-Service Since the 2023 IRP

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area

- Installs a 345 kV, 200-MVAr switched shunt reactor at Mona substation
  - Project driver was to address the high voltage conditions experienced during steady state operations under light load and light transfer conditions
  - Benefits include more effective high voltage control and safe and more reliable power for the Utah area by reducing lines taken out of service and preservation of substation equipment life, particularly circuit breakers which are exposed to frequent switching, reduced probability of mis operation and increased maintenance costs.

2. Northern Utah/Southeast Idaho Area

- Constructed a new 345 kV yard adjacent to the existing Bridgerland 138 kV substation. Looped in the existing Populus – Terminal 345 kV line into Bridgerland and Ben Lomond substations.
  - Project driver was to resolve System Operating Limit on Path C.
  - Benefits include the ability to maintain the WECC Path C rating to 1600 MW southbound and 1250 MW northbound.

3. Salt Lake City Utah area

- Install two capacitor banks at Magna Substation and rebuild the Tooele – Pine Canyon 138 kV transmission line
  - Project driver was to correct N-1 contingency overload and low voltage issues at Magna substation and on the Tooele – Pine Canyon 138 kV line from consistent load growth and new block loads.
  - Benefits included mitigating the risk of thermal overloads and low voltage issues, adding additional capacity to address projected load growth and improve transmission reliability

4. Southern Utah area

- Reconductor 2.57-miles of the St. George-Purgatory Flat 138 kV transmission line.
  - Project driver was to increase the thermal rating of the line which loaded to 95 percent of its continuous summer thermal rating summer 2022.
  - Benefits included the increases of the transmission line summer continuous rating by 63 MVA.

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

PacifiCorp West (PACW) Control Area

1. Klamath Falls Oregon Area

- Constructed a second 230 kV transmission line from Snow Goose to Klamath Falls substation.
    - Project driver was to resolve NERC Standard TPL-001-5 Category P6 (N-1-1) for a double contingencies on the 230-kV system serving Yreka, Klamath Falls and La Pine area for the loss of the Klamath Falls-Snow Goose 230 kV line and either the Lone Pine-Copco 230 kV line or Bonneville Power Administration's (BPA) Pilot Butte-La Pine 230 kV line can cause a voltage collapse affecting a large region of the southern Oregon and northern California system.
    - Benefits included reinforcing 230 kV system between in Klamath Falls area to cover TPL-001-5 category P6 (N-1-1) contingencies during all operating conditions on the existing system and minimize risk of a large-scale outage to customers throughout the Klamath Falls and Yreka areas.

2. Prineville Oregon Area

- Construct a second 115 kV line between Houston Lake and Ponderosa substations.
    - Project driver was to eliminates potential N-1 overloads of the Prineville 115 kV system associated with increased load, changing generation mix, and grid flow conditions in the area.
    - Benefits included the elimination of a NERC Standard TPL-001-5 Category P1 contingency event for a fault on the 115 kV line between Baldwin Road and Ponderosa substation or a fault on the 115 kV line between Houston Lake and Stearns Butte.

Planned Transmission System Improvements

PacifiCorp East (PACE) Control Area

1. Central Utah Area

- Upgrade the 345-138 kV 167-MVA transformer at Camp Williams substation to a 345-138 kV 700-MVA transformer
    - Project driver is to correct NERC Standard TPL-001-5 Category P6 deficiencies during peak summer loading conditions for the N-1-1 event of losing both Spanish Fork substation 345-138 kV transformers that would cause thermal overloads to the Camp Williams 345-138 kV transformer and the Clover – Nebo 138 kV line.
    - Benefits include mitigating the NERC Standard TPL-001-5 Category P6 deficiencies. Provides additional 345 kV source to northern Utah Valley and Jordan Valley as well as increase system reliability
- Install a second 345-138 kV 700 MVA transformer at Oquirrh substation
    - Project driver is to correct N-1 contingency overload issues in the South Jordan area.

- Benefits include increasing capacity on the 138 kV network serving the Salt Lake Valley.

- Construct a new 345 kV line between Spanish Fork and Mercer 345 kV substations
  - Project driver is to eliminate the need for the Lakeside II Remedial Action Scheme (RAS) and prevent generation shedding during contingencies. Once flows across the Wasatch Front South boundary exceed 5,562 MW, the Lakeside RAS is no longer effective and cannot be modified to accommodate more flow.
  - Benefits include the increase of path limit to 6,300 MW and allow 1,000 MW additional generation to be interconnected in southern Utah

2. Utah, Idaho & Wyoming - Upgrade Program – Replace Over-dutied Circuit Breakers
   - Replaced breakers identified as over-dutied with higher-capability breakers in various substations located in Idaho, Utah, and Wyoming
     - Project driver was to correct NERC Standard TPL-001-5 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of 12 substations to be addressed as required per R2.8.
     - Benefits include eliminating the risk of over-dutied breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-5 Requirement R2.3 deficiencies and as required per R2.8.
3. Salt Lake City, Utah Area
   - Convert North Salt Lake Substation to 138-kV
     - Project driver is to correct N-1 contingency overload issues in the North Salt Lake area.
     - Converting to 138 kV at North Salt Lake substation increases the capacity in the area while mitigating the contingency overloads, reduces the burden on the 46 kV system, and brings better reliability to the customers in the area.
   - Loop the 90th South – Terminal 345 kV line into and out of the Midvalley 345 kV yard
     - Project Driver is to eliminate identified overloading of the 90th South – Midvalley 345 kV #1 line under heavy transfer conditions across the Wasatch Front South boundary.
     - Benefits include increasing the transfer capability across the Wasatch Front South boundary by 45-MW, improving operating flexibility, and allowing additional transfers from Clover/Mona as well as from southern Utah to the Wasatch Front.
   - Construct a new 230-46 kV substation near Eden, Utah.
     - Project driver is to provide a transmission loop to the area to facilitate a line rebuild through Ogden Canyon.
     - Benefits include improved future reliability and area capacity.
4. Southeast Idaho Area
   - Install a 25 MVAR shunt capacitor bank at the Franklin 138 kV substation.
     - Project driver is to correct NERC Standard TPL-001-5 Category P1 (N-1) contingency events for the loss of the Treasureton – Franklin 138 kV line.

  - Benefits include resolving the NERC Standard TPL-001-5 Category P1 voltage issues

PacifiCorp West (PACW) Control Area

1. Eastern Oregon Area
   - Replace the entire Burns 500 kV reactive station, including the series capacitor bank, bypass breakers, shunt reactors, and all switches and circuit switchers.
     - Project driver is to replace obsolete and degrading assets to prevent equipment failure which would result in a substantial financial impact and limiting Jim Bridger and Wyoming wind generation for an extended time.
     - Benefits include replacement of obsolete equipment with modern SCADA-operable equipment (reducing operational labor), reduces the risk of failure, and improves recovery time.
2. Portland Oregon Area
   - Reconfigure and convert the existing Bonneville Power Administration’s (BPA) St. Johns – Columbia and PacifiCorp’s (PAC) Columbia – Knott 57 kV lines, and a portion of the idle 69 kV line north of Albina to 115 kV
     - Project driver is to correct NERC Standard TPL-001-5 Category P6 (N-1-1) deficiencies for load loss of up to 62-MW in the urban northeast Portland core area and Category P6 (N-1-1) deficiencies for voltage issues on the 57 kV system.
     - Benefits include resolution of NERC Standard TPL-001-5 Category P6 (N-1-1) deficiencies, elimination of the 57 kV system voltage in the North Portland and creates a third 115 kV path between the St. Johns/Rivergate and the Knott/Albina area.
3. Roseburg Oregon Area
   - Convert the 69 kV transmission Lines 30 and 65 to 115 kV, along with four distribution substations and construct a new 115 kV tie from Roberts Creek to the converted Green substation.
     - Project driver is to resolve multiple capacity limitations in the area; notably the Roberts Creek 115-69 kV transformer, the Winchester 115-69 kV transformer, Line 66 between Dixonville and Sutherlin and Line 65 between Dixonville and Southgate. 12 system problems were identified as being affected by these limitations.
     - Benefits include improvement of operability of the system to increase reliability during outages and maintenance and gives the system enough excess capacity to accommodate 20 years of growth at a 1.3 percent per year rate.
   - Replace the existing 230-115 kV transformer at Dixonville substation with a new 280 MVA transformer.
     - Project driver is to resolve excess voltage on the 115 kV bus. The current transformer steady state voltage sits at 10.4 percent above nominal in the North Umpqua Hydroelectric System and is nearly 8.7 percent above nominal at Dixonville substation.
     - Benefit includes bringing the 115 kV bus voltage at Dixonville to operate within an acceptable range and avoids excessive voltage throughout the Roseburg and North

Umpqua areas extending the life of the transformers as well as all the downstream equipment.

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

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

CHAPTER 5 – RELIABILITY AND RESILIENCY

CHAPTER HIGHLIGHTS

- Regional resource adequacy assessments highlight that there are resource adequacy risks through the mid-2020s. In conditions of increased demand and resource variability, higher summer temperatures reduce excess energy supply, in turn tightening supply from the market.
- PacifiCorp's wildfire mitigation plans, which outline a risk-based, balanced, and integrated approach, contain six critical focus areas of planning and execution for a reliable and resilient energy future: (1) Risk analysis and drivers, (2) Situational awareness, (3) Inspection and correction, (4) Vegetation management, (5) System hardening, and (6) Operational practices.
- The 2025 IRP preferred portfolio includes the Energy Gateway South (GWS) and Energy Gateway West segment D.1, which are currently operational. The preferred portfolio also includes future transmission upgrades that support the transition to renewable energy by providing access to low-cost, location-specific renewable resources, and additional transfer capability, which enables greater use of low-cost resource options and relieves stress on current assets.

Introduction

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

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

Supply-Based Reliability

Regional Resource Adequacy

As part of its 2025 IRP, PacifiCorp has conducted a review and evaluation of western resource adequacy studies and information,.

In December 2024 the Western Electricity Coordinating Council (WECC) published the Western Assessment of Resource Adequacy (WARA), which serves as an interconnection-wide assessment of resource adequacy as discussed below. PacifiCorp also reviewed the 2020 North American Electric Reliability Council (NERC) Long-Term Reliability Assessment and the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

WECC Western Assessment of Resource Adequacy Report

The WECC WARA was published in December 2024 and was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years.[1] The analysis is probabilistic and represents an hourly assessment of resource adequacy over the study period. A key driver of the results is the forecasted growth in load across the west, which is projected to increase by over 20.4% in the next ten years (on an energy basis), more than double the 9.6% growth forecast from the 2022 WARA. PacifiCorp's loads are located in the NW-Northwest and NW-Central regions evaluated as part of the WARA. Peak demand in the NW-Northwest region is forecasted to grow by 13.5% in the next ten years, while the NW-Central region is forecasted to grow by 8.5% over the same time period. While significant, these are both lower than the growth of the Western Interconnection as whole, where growth is projected at 17.2%, driven by increases in California and the Desert Southwest.

Resource plans have identified a vast quantity of resources to meet this demand, 172 GW of new generation resources, which is more than double the generation capacity added in the last ten years. Plans include 68 GW of solar capacity additions in the next ten years, while will nearly triple the 35 GW in operation in 2023, plus 40 GW of wind capacity additions in the next ten years, relative to 37 GW in operation in 2023. Similarly, battery storage is projected to grow by 37 GW. The WARA highlights concerns that planned resources will not be brought online in a timely manner and includes four scenarios evaluating various levels of resource build out.

In the All Additions scenario, which includes all planned resources, the WARA identifies risks in the NW-Northwest region, primarily in the winter, and primarily in 2029 and later. Risks increase and appear in other regions if lower levels of planned resources are achieved, as summarized in Table 5.1.

Table 5.1 – WARA Demand-at-Risk Summary[2]

	Month					55% Resource Additions Scenario						
Region	1	2	3	4	5	6	7	8	9	10	11	12
California	-	-	-	-	-	-	-	-	-	-	-	-
Desert Southwest	-	-	-	-	-	-	Medium	Medium	Low	-	-	-
NW-Northwest	High	High	Medium	Low	-	-	Low	Medium	Medium	High	High	High
NW-Northeast	-	Low	-	-	-	-	Low	Medium	-	-	-	-
NW-Central	-	-	-	-	-	Low	Medium	Medium	Medium	-	-	-

	Month					85% Resource Additions Scenario						
Region	1	2	3	4	5	6	7	8	9	10	11	12
California	-	-	-	-	-	-	-	-	-	-	-	-
Desert Southwest	-	-	-	-	-	-	-	-	-	-	-	-
NW-Northwest	Medium	Medium	-	-	-	-	-	Low	-	Medium	Low	Medium
NW-Northeast	-	Low	-	-	-	-	-	Low	-	-	-	-
NW-Central	-	-	-	-	-	Low	Low	Low	Medium	-	-	-

Risk reflects the count of hours in each month that exceed a one-day-in-ten-years threshold by 2034.
High >50 hours Medium 10-49 hours Low <10 hours

The NW-Northwest and NW-Central regions which include PacifiCorp's load both have hours at risk. In the NW-Northwest region, significant risk exists in both the summer and winter

[1] WECC. Western Assessment of Resource Adequacy 2024. Available online: https://feature.wecc.org/wara/ (accessed 12/18/2024)
[2] WECC. WARA 2024 Demand-at-Risk Hours by Subregion. Available online at: https://www.wecc.org/wecc-document/17071 (Accessed 12/18/2024)

seasons. While PacifiCorp has significant transfer capability into the NW-Northwest and proportionately lower dependence on hydropower than the NW-Northwest region as a whole, regional capacity limitations would result in less margin for error. In the NW-Central region, risks are somewhat lower, and concentrated in the summer, but still indicate that incremental resources are necessary to serve growing loads. The results shown assume import capability between sub-regions – in the absence of imports, risks are high in the NW-Northwest and NW-Central regions even if all planned new resources are built.

The WARA characterizes four risks that impact planned resource additions: supply chain disruptions, interconnection queue, siting delays, and increased costs. Some of the impacts are reduced as a result of PacifiCorp's particular circumstances. PacifiCorp's relatively large portfolio and geographic footprint create a wider range of opportunities than are available to many other utilities, increasing the likelihood that some new projects will be able to proceed. This is bolstered by PacifiCorp's implementation of a cluster study interconnection process in 2020, which has enabled large numbers of interconnection requests to be processed more quickly than was possible in the past, increasing the likelihood that projects will be available in desired timeframes. After cost-effective projects are identified, PacifiCorp's relatively large demand allows it to contract with multiple developers for multiple sites, reducing the impact if any single developer or site falls through or is delayed. That said, substantial risks remain for any resource additions.

The WARA also characterizes risks associated with several other factors: resource variability, transmission considerations, energy policy, and extreme weather. The limitations of wind, solar, and energy-limited resources like energy storage are different from those of baseload or dispatchable resources, and those limitations become more restrictive as the share of these resources increases. Given the expected tripling of solar capacity and doubling of wind capacity, variability is expected to increasing significantly. The variability and operational requirements of that future resource mix is not fully characterized, and could be impacted further by extreme weather events. The other risk factors cover a range of planning and policy considerations, and the process through which resource and transmission build outs are implemented. Utility planning and procurement takes time, and the build out of resources and transmission is reliant upon a range of state and federal processes and requirements.

NERC Long-Term Reliability Assessment (LTRA)

Resources

As part of the regional reliability assessment to support the 2025 IRP, PacifiCorp reviewed and incorporated learnings from the NERC LTRA, published in December 2024.[3] The NERC LTRA

[3] NERC. 2024 Long-Term Reliability Assessment. December 2024. Available online at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (accessed 12/18/2024)

organizes prospective resources into three broad capacity supply categories in its 10-year WECC region reliability assessment:

- Tier 1: resources under construction, or with signed contracts.
- Tier 2: resources with completed interconnection studies.
- Tier 3: resources in an interconnection queue that do not meet the Tier 2 requirement.

Planning Reserve Margin

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

Comparing the *anticipated* resource-based reserve margin to the reference planning margin yields one of three risk determinations:

- High Risk: shortfalls may occur at normal peak conditions
- Elevated Risk: shortfalls may occur in extreme conditions
- Normal Risk: low likelihood of electricity supply shortfall

WECC Subregions

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

Table 5.2 – WECC Subregion Descriptions

Designation	Subregion	Country	Peak
NW	The rest of WECC, beyond the exceptions listed below	United States	Summer
SW	Primarily Arizona and New Mexico	United States	Summer
CA/MX	California / Mexico	United States	Summer
AB	Alberta	Canada	Winter
BC	British Columbia	Canada	Winter

LTRA WECC Assessment

Table 5.3 presents the WECC LTRA assessments for the three WECC subregions that include the United States. Anticipated Reserve Margin is based on existing resources, firm transfers, and Tier 1 additions, less confirmed retirements. Prospective Reserve Margin adds existing resources without firm transmission, or with other potential limitations, likely transfers, and Tier 2 capacity additions, less unconfirmed retirements. Values that fall below the reference margin level (i.e. planning target) are highlighted.

Table 5.3 – NERC LTRA for Selected WECC Subregions

WECC-NW

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	38.7%	37.7%	34.1%	29.3%	23.3%	17.0%	10.8%	8.9%	6.7%	4.6%
Prospective Reserve Margin (%)	39.9%	40.6%	37.8%	34.2%	30.0%	25.7%	20.4%	18.4%	15.7%	13.9%
Reference Margin Level (%)	*16.3%*	*15.8%*	*15.9%*	*15.4%*	*14.7%*	*14.5%*	*14.3%*	*14.2%*	*14.4%*	*13.8%*

WECC-SW

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	36.9%	35.6%	31.8%	24.2%	17.4%	11.3%	7.7%	0.2%	-4.7%	-8.7%
Prospective Reserve Margin (%)	38.6%	40.1%	38.2%	31.1%	26.7%	20.4%	16.8%	9.2%	4.9%	0.0%
Reference Margin Level (%)	*11.0%*	*10.8%*	*12.0%*	*11.7%*	*10.2%*	*10.1%*	*9.9%*	*9.7%*	*10.8%*	*9.4%*

WECC-CA/MX

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Anticipated Reserve Margin (%)	45.8%	45.2%	38.4%	43.1%	28.8%	29.6%	23.3%	25.0%	15.2%	11.1%
Prospective Reserve Margin (%)	51.8%	55.1%	48.2%	62.5%	45.6%	57.9%	51.0%	59.0%	50.2%	47.3%
Reference Margin Level (%)	*17.4%*	*17.4%*	*16.4%*	*17.4%*	*16.6%*	*16.4%*	*16.1%*	*16.3%*	*14.9%*	*15.3%*

As shown, the WECC-NW subregion that includes PacifiCorp's load meets the reference margin with anticipated resources through 2030, and with prospective resources through the ten year horizon. The WECC-SW subregion also meets the reference margin with anticipated resources through 2030, but only has sufficient prospective resources through 2031. The WECC-CA/MX region meets the reference margin with anticipated resources through 2033, and with prospective resources through the ten year horizon. While this presents a relatively favorable view of supply and demand, the LTRA definition of Tier 1 resources includes everything with an interconnection agreement and/or power purchase agreement. Not all such resources will ultimately be brought online in a timely manner. The factors identified the WECC WARA (supply chain disruptions, interconnection queue, siting delays, and increased costs) can all derail projects that are otherwise feasible.

Pacific Northwest Power Supply Adequacy Assessment

The Northwest Power and Conservation Council released its 2029 Adequacy Assessment in August 2024.[4] Starting in 2011, an annual loss-of-load-probability of up to five percent was deemed adequate. Starting with the 2023 assessment a multi-metric framework of shortfall frequency, duration, and magnitude was used. These metrics include:

- **Loss of load events (LOLEV):** limits the expected frequency of shortfall events to protect against frequent use of emergency measures.
- **Duration Value at Risk**: limits shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
- **Peak Value at Risk**: limits maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
- **Energy Value at Risk**: limits total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

An adequate system must meet all of these metrics. The 2029 Adequacy Assessment is based on the 2021 Northwest Power Plan, discussed below, with updates for expected changes through

[4] Northwest Power and Conservation Council. Pacific Northwest Power Supply Adequacy Assessment for 2029. August 2024. Available online at: https://www.nwcouncil.org/fs/18853/2024-4.pdf (accessed 12/18/2024)

2029, including load growth, resource development, and transmission. Based on updated results for adequacy in year 2029, the 2029 Adequacy Assessment concludes that power supply would be adequate under reference conditions. This conclusion is in part based on coal plants changing to natural gas, rather than retiring (including Jim Bridger 1 and 2, which were converted in 2024). The 2029 Adequacy Assessment identifies two scenarios that could lead to reliability shortfalls. First, if energy efficiency savings only meet the low end of the targeted quantity, shortfall risks increase in the winter. Second, higher data center loads in the absence of commensurate resource supply could lead to reliability shortfalls in both the winter and the summer. An additional potential risk is related to the Boardman-to-Hemingway project which the 2029 Adequacy Assessment assumes is operational by 2029, increasing transfer capability between Idaho and the Pacific Northwest, as this upgrade is not part of PacifiCorp's 2025 IRP preferred portfolio. The metric results from the 2029 Adequacy Assessment are provided in Table 5.4, with shortfalls highlighted in orange.

Table 5.4 – Northwest Power and Conservation Council 2029 Adequacy Assessment

Type	Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Winter LOLEV	0.1	0.022	0.35	1.294
Frequency	Summer LOLEV	0.1	0.017	0.033	0.3
Duration	Duration VaR 97.5	8 hours	0	1.5	20.6
Magnitude	Peak VaR 97.5	1200 MW	0	1,567	3,076
Magnitude	Energy VaR 97.5	9600 MWh	0	4,196	196,324

Western Resource Adequacy Program (WRAP)

The WRAP is a regional reliability planning and compliance program, intended to help facilitate region-wide resource adequacy, and initiated on behalf of the utilities that are part of the Western Power Pool (formerly the Northwest Power Pool). WRAP allows for coordination and visibility of resource needs and supply among the participants, taking advantage of the diversity and sharing from pooling resources.

WRAP begins with regional analysis, as the program sets regional reliability metrics for upcoming seasons, including planning reserve margins that are applied to loads and qualifying capacity contributions that apply to resources. With those values in hand, utilities must secure resources and, seven months prior to the start of a winter or summer season, must submit a forward showing demonstrating they have resources and transmission to cover their load and planning reserve margin requirements. Some time is provided to cover shortfalls before the season begins. Within the season, an operational component allows those participants with a day-ahead resource shortfall to call upon the program and receive incremental resources from participants who have a surplus.

WRAP is based on two seasons: summer (June through September) and winter (November through March). Planning reserve margins vary by month, and also by region, as WRAP covers two regions: the Pacific Northwest (primarily Oregon and Washington and British Columbia, with parts of northern Idaho and Montana) and the Desert Southwest, including the remainder of Idaho, Utah, Wyoming, Colorado, Nevada, and Arizona. Similarly, monthly qualifying capacity contributions are calculated for each resource, and capture technology type, regional variations, and resource-specific performance. For example, wind and solar contributions incorporate a resource's output during capacity critical hours (the highest load hours after netting out wind, solar, and run of river hydro generation).

As of September 2024, the Western Power Pool Board of Directors has approved updates to the WRAP tariff along with seven business practice manuals detailing of the program will operate. WRAP is currently operational with non-binding requirements and has plans in place to enable fully binding operations in Summer 2027 for participants that provide notice of their intent by January 2026. All participants will be binding for Winter 2027-2028 (i.e. starting November 2027).

PacifiCorp is currently participating in WRAP and is working with the Western Power Pool to address a number of outstanding issues, including the interaction between WRAP and the CAISO's Enhanced Day-Ahead Market (EDAM) and complexity from PacifiCorp's footprint spanning both WRAP regions. While some issues remain, PacifiCorp's 2025 IRP includes modeling to capture WRAP compliance requirements starting in 2028 and continuing through the study horizon. While proxy resource selections within the 2025 IRP can only begin on January 1st of each year, actual resource procurement could be targeted to the November 2027 start date to the extent necessary, or short-term products could be used to address unmet requirements, if any.

Reliable Service through Unpredictable Weather and Challenging Market Liquidity

PacifiCorp, other utilities, and power marketers who own and operate generation engage in market purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp previous IRP modeling has included front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help PacifiCorp cover short positions. However, market transactions that are not based on a specified source do not provide qualifying capacity for WRAP compliance. While other short-term products exist, such as slices of hydropower projects on the Mid-Columbia or tolling agreements for merchant-owned natural gas plants, there are relatively few such opportunities and there may be significant competition for such products given rising demand and stricter resource adequacy requirements under WRAP. With that in mind, for the 2025 IRP, PacifiCorp is not including short-term market products as options for WRAP compliance.

WRAP compliance does not guarantee reliability, in particular a monthly qualifying capacity contribution value does not ensure resources will be available to meet hourly requirements such as the hourly balancing test in the EDAM. At the same time, PacifiCorp recognizes that increasing coordination of spot market transactions through EIM, EDAM, and WRAP is likely to provide significant economic benefits. To balance the limitations of market transactions for capacity and reliability requirements and the benefits of market transactions for regional dispatch, the 2025 IRP does not allow market purchases in certain key periods, but otherwise allows market purchases up to transmission limits. During the summer WRAP season (June through September), market purchases are not allowed from 4:00 p.m. to 12:00 a.m. on PacifiCorp's top five load days in each month. Similarly, in the winter WRAP season (November through March), market purchases are not allowed from 4:00 a.m. to 8:00 a.m. as well as 4:00 p.m. to 12:00 a.m., again on PacifiCorp's top five load days in each month. For the 2025 IRP, PacifiCorp is also differentiating market prices within each month, to reflect historical patterns on the days used to derive the chaotic normal load forecast and reflecting the same weather conditions used to develop wind and solar generation profiles. In general, market prices are higher when load is high and wind and solar output is relatively low, though market prices reflect region-wide conditions of PacifiCorp's supply and demand is only a part. Market prices in EIM and EDAM will reflect the balance of supply-and-demand, and surplus supply from PacifiCorp is likely to result in lower market clearing prices. While this effect is not captured in PacifiCorp's hourly market price forecast, market sales for the 2025 IRP have been capped at historical average levels, since large surpluses would impact pricing.

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

Planning for Load Changes as a Result of Climate Change

Recent weather-based reliability events throughout the United States have underscored the need for utilities to consider the potential for increasingly extreme weather and the underlying reliability challenges that may be caused as part of its planning process. PacifiCorp has accounted for climate change within the 2025 IRP to assess the ways in which climate change may impact planning assumptions.

The Company's load forecast is based on historical actual weather adjusted for expectations and impacts from climate change. The historical weather is defined by the 20-year period of 2004 through 2023. The climate change weather uses the data from the historical period and adjusts the percentile of the data to achieve the expected target average annual temperature and calculate the HDD and CDD impacts and peak producing weather impacts within the energy forecast and peak forecast, respectively. These temperature changes lead to higher summer peaks and lower winter peaks, with increasing impacts across the study horizon. See Appendix A for additional detail regarding how climate change is incorporated into the load forecast.

Weather-Related Impacts to Variable Generation

New for the 2025 IRP, all wind and solar generation profiles are based on historical weather conditions on the same historical day underlying the load forecast. This captures the relationship between load, wind, and solar that happened in recent history. Each month of the Company's chaotic normal load forecast reflects the range of weather conditions experienced in the most typical month from 2013-2022, while stochastic analysis for the 2025 IRP will reflect the range of weather conditions experienced in every year from 2006-2023. The effect of extreme weather events associated with climate change is an evolving area of research that is growing in importance as renewable, intermittent resources dependent upon wind, solar, and hydrologic conditions comprise an increasing proportion of utility resource portfolios. For the 2025 IRP, PacifiCorp is not projecting specific climate impacts on wind and solar generation, but notes that recent history may be more representative of future conditions than earlier conditions. As a result, reliability and system cost risks identified using inputs derived from recent historical years may be of greater concern as an indicator of future risk.

Wildfire Impacts

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

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

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

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

PacifiCorp outlines its wildfire mitigation strategies later in this document.

Extreme Weather Impacts

Climate change also has the potential to result in increased frequency and magnitude of extreme weather events. Such changes can result in more frequent and intense precipitation events and flooding, which could impact hydropower generation and change historic operating practices to maintain flood control capabilities at projects where flood control benefits are part of project operations. Like wildfire events, increased flooding has the potential to impact access to remote hydro facilities. Increased precipitation and reduced snow water equivalent have the potential to modify runoff patterns impacting hydro generation but is not expected to impact dam safety at

PacifiCorp hydro facilities, which are subject to FERC dam safety requirements that ensure they are able to safely pass probable maximum flood events. Increases in extreme weather that results in more frequent flood events has the potential to increase debris loading in river systems and reservoirs, potentially increasing generation downtime to remove debris that may reduce inflows to hydro units or reduce flows through fish screens.

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

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

Impacts on wind and solar energy

The impact on renewable energy generation due to extreme weather events and climate change is an evolving topic. For conclusive trends of climate change impact, data collection specific to geographic locations is critical. Climate impacts both the demand and supply side of energy. Due to daily or seasonal changes the demand for energy patterns is changing. On the supply side due to increasing temperatures and variability in climate parameters it impacts estimated energy outputs of projects as well as operational costs. However, there are limited studies in the North American region that quantitatively document the impact of a climate parameter on the future of wind and solar energy.[5] Some broad impacts anticipated from climate change are noted below:[6]

Wind Energy

- Changes to wind speed: could impact energy assessments
- Changes in temperature: with increased temperatures the air density could reduce energy outputs
- Changes in seasonal or daily wind: could disrupt correlation between wind energy and grid load demand
- Rising sea levels: could damage offshore wind farm infrastructure

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

Solar Energy

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

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

Wildfire Risk Mitigation

PacifiCorp's Wildfire Mitigation Plans (WMPs) are designed to meet regulatory requirements while delivering safe and reliable power. These plans focus on enhancing situational awareness, implementing robust operational practices, and hardening the power system to mitigate wildfire risks while balancing customer and community impacts.[7]

PacifiCorp Wildfire Mitigation Plan Regulatory Compliance

PacifiCorp meets regulatory requirements through the submittal of Wildfire Mitigation Plans (WMPs) with the specific regulatory alignments for each state stated below:

1. **California**: The WMP complies with California Senate Bill 901 and the California Public Utilities Commission (CPUC) provisions under Section 8386.
2. **Idaho**: The WMP was submitted in accordance with Idaho Public Utilities Commission Order No. 36045.
3. **Utah**: The WMP adheres to Utah Administrative Code R746-315-2, effective June 1, 2023, and complies with Subsection 54-24-201.
4. **Oregon**: The WMP meets the requirements set forth in Oregon Administrative Rule 860-300-0040.
5. **Washington**: The WMP was submitted on October 31, 2024, and compliance with statutory requirements was confirmed by the Washington Utilities and Transportation Commission as complying with the Revised Code of Washington (RCW) 80.28.440.

Although Wyoming does not have regulatory requirements for a wildfire mitigation plan, PacifiCorp has proactively filed one in conjunction with the general rate case.

Core Principles

All WMPs are publicly accessible via the PacifiCorp Wildfire Mitigation Plan website (linked here). These plans detail the investments and strategies for constructing, maintaining, and operating electrical lines and equipment for wildfire mitigation projects and programs. While there

[7] Wildfire mitigation and impacts were discussed in the 2025 IRP public input meeting series and stakeholder feedback. See Appendix M, stakeholder feedback form #18 (Wyoming Office of Consumer Advocate).

are state-specific requirements, the core strategy across all six states remains consistent, guided by the following principles:

- **Situational Awareness and Operational Readiness**: Implementing systems that enhance situational awareness, and operational readiness is crucial for mitigating fire risks and their impacts.
- **Operational Practices**: Minimizing the impact of fault events through rapid isolation using advanced equipment and trained personnel.
- **System Hardening**: Reducing the frequency of ignition events by engineering more resilient systems that experience fewer faults.

Balancing Mitigation and Community Impact

PacifiCorp is committed to balancing wildfire risk mitigation with the needs of customers and communities. Adjustments to power system operations, such as modifying protective device settings and testing protocols, are carefully considered to reduce wildfire risks. These measures are applied selectively to avoid unnecessary disruptions to the power supply.

The wildfire mitigation program approach includes deploying advanced technologies like fault indicators and assessing outages to inform short-term mitigation projects. These efforts are designed to enhance safety while maintaining reliable service.

PacifiCorp's Wildfire Mitigation Plans (WMPs) reflect the Company's dedication to balancing costs, benefits, operational impacts, and risk mitigation with the goal to provide safe, reliable, and affordable electric service, prioritizing the well-being of customers and communities.

Transmission-Based Reliability

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

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

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

Federal Reliability Standards

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

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

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

In addition to the TPL Standards, PacifiCorp is also required to comply with FERC Order 1000 as detailed in Attachment K of the Open Access Transmission Tariff (OATT) which requires PacifiCorp to participate in regional transmission planning processes that satisfy the transmission planning principles of FERC Order 890 and produce a regional transmission plan. To meet this requirement PacifiCorp is a member of the NorthernGrid regional planning association. The development of the regional transmission plan ensures the regional reliability is maintained and/or enhanced with the addition of new planned generation and transmission projects while reliably serving PacifiCorp customers. In 2024, FERC issued Order 1920 which will further expand regional planning processes, including a requirement for a long-term (20 year) regional plan. PacifiCorp is working with NorthernGrid members to draft tariff revisions to outline the expanded process in preparation for the FERC required compliance filing in August 2025.

Power Flow Analyses and Planning for Generator Retirements

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

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

CHAPTER 6 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

- New for the 2025 IRP, PacifiCorp is calculating its capacity position based on Western Resource Adequacy Program (WRAP) compliance requirements, with binding operations under the program expected to begin by 2028. WRAP participants with projected resource shortfalls on a day-ahead basis will be able to purchase from WRAP participants with excess supply.
- Every resource has a qualifying capacity contribution (QCC) for each month of the summer (June-September) and winter (November-March) seasons. These values are calculated by WRAP based on resource-specific historical performance and are based on the loads and resource mix of the regional participants. These values are updated by WRAP ahead of each compliance season.
- Seven months prior to the start of each season, WRAP participants must make a forward showing, demonstrating that the QCC for their resources is sufficient to meet their peak load plus a monthly planning reserve margin determined by WRAP.
- While WRAP is projected to enhance reliability by providing priority access to supply from other participants, the monthly QCC values do not ensure a utility will be reliable or have sufficient resources to meet its requirements from hour to hour, so hourly analysis of the load and resource balance is also necessary.
- On both a capacity and energy basis, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements.
- The company's load obligation is calculated based on projected load less distributed generation, energy efficiency savings, and demand response, including interruptible load.
- A distributed generation study prepared by DNV produced estimates on distributed generation penetration levels specific to PacifiCorp's six-state territory. The study provided expected penetration levels by resource type, along with high and low penetration sensitivities. PacifiCorp's 2025 IRP load and resource balance reflects base case distributed generation penetration levels as a reduction in load.
- Relative to WRAP compliance requirements, PacifiCorp's system is capacity deficient (before adding proxy resources other than energy efficiency, and without considering short-term capacity procurement, i.e. market purchases) in the summer beginning in 2026, and the winter peaks throughout the planning horizon.
- The uncertainty in the company's load and resource balance is increasing as PacifiCorp's resource portfolio and customer demand evolve over time. PacifiCorp's 2025 IRP reflects renewable resource generation profiles based on the same patterns of historical weather conditions used to develop its load forecasts, both on a normalized basis and for stochastic analysis. While adjustments to account for climate change are included in the base forecast, customer demand may be further influenced by climate change directly as well as indirectly through electrification, with uncertain impacts on future demand. These resources and load relationships ultimately drive the frequency and characteristics of the relatively extreme conditions that are most likely to trigger reliability shortfalls.

Introduction

This chapter presents PacifiCorp's assessment of its load and resource balance. PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system are summarized in Volume II, Appendix A (Load Forecast Details). The summary-level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, assumed coal unit retirements and incremental new energy efficiency savings from the preferred portfolio, before adding new generating resources.

System Coincident Peak Load Forecast

System Coincident Peak Load Forecast
The system coincident peak load is the annual maximum hourly load on the system. The 2025 IRP relies on PacifiCorp's May 2024 load forecast. Table 6.1 shows the annual summer coincident peak load stated in megawatts (MW) as reported in the capacity load and resource balance before any load reductions from energy efficiency. The system summer peak load grows at a compound growth rate (CAGR) of 1.91 percent over the period 2025 through 2044.

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

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
System	11,374	11,410	11,708	12,085	12,303	12,501	12,824	12,961	13,156	13,358
	2035	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
System	13,603	13,919	14,190	14,479	14,764	15,065	15,368	15,785	16,026	16,307

Existing Resources

Thermal Plants

Table 6.2 lists PacifiCorp's existing coal-fueled plants and Table 6.3 lists existing natural-gas-fueled plants. The "End of Coal-fired Operation" reflects the year a resource must retire or converts to natural gas (if option is available) as reflected in modeling inputs.

Table 6.2 – Coal-Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Nameplate Capacity (MW)	End of Coal-fired Operation
Colstrip 3	10	Montana	74	2025 (Transfer capacity to unit 4)
Colstrip 4	10*	Montana	74	2029 (PacifiCorp exit)
Craig 1	19	Colorado	82	2025 (Assumed end of life)
Craig 2	19	Colorado	79	2028 (Assumed end of life)
Dave Johnston 1	100	Wyoming	99	2028 (Gas conversion option)
Dave Johnston 2	100	Wyoming	106	2028 (Gas conversion option)
Dave Johnston 3	100	Wyoming	220	2027 (Retire: Clean air compliance)
Dave Johnston 4	100	Wyoming	330	
Hayden 1	24	Colorado	44	2028 (Assumed end of life)
Hayden 2	13	Colorado	33	2027 (Assumed end of life)
Hunter 1	94	Utah	418	
Hunter 2	60	Utah	269	
Hunter 3	100	Utah	471	
Huntington 1	100	Utah	459	
Huntington 2	100	Utah	450	
Jim Bridger 3	67	Wyoming	349	
Jim Bridger 4	67	Wyoming	351	
Naughton 1	100	Wyoming	156	2025 (Gas conversion option)
Naughton 2	100	Wyoming	201	2025 (Gas conversion option)
Wyodak	80	Wyoming	268	
TOTAL – Coal			**4,533**	

*PacifiCorp's share of Colstrip 4 is projected to include its current ownership of Colstrip 3 starting in 2026.

Table 6.3 – Natural Gas-Fired Plants

Plant	PacifiCorp Percentage Share (%)	State	Nameplate Capacity (MW)
Chehalis	100	Washington	500
Currant Creek	100	Utah	540
Gadsby 1	100	Utah	64
Gadsby 2	100	Utah	69
Gadsby 3	100	Utah	105
Gadsby 4	100	Utah	40
Gadsby 5	100	Utah	40
Gadsby 6	100	Utah	40
Hermiston	100	Oregon	237
Jim Bridger 1	67	Wyoming	354
Jim Bridger 2	67	Wyoming	359
Lake Side	100	Utah	580
Lake Side 2	100	Utah	677
Naughton 3	100	Wyoming	247
TOTAL – Natural Gas			**3,852**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 5,154 MW of wind resources. Table 6.4 shows existing (or under construction) wind facilities owned by PacifiCorp, while Table 6.5 shows existing wind power-purchase agreements (PPAs).

Table 6.4 – Owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)
Goodnoe Hills East	WA	94
Leaning Juniper	WA	101
Marengo I	WA	156
Marengo II	WA	78
Cedar Springs 2	WY	199
Dunlap 1	WY	111
Ekola Flats 1	WY	250
Foote Creek I	WY	41
Glenrock I	WY	99
Glenrock III	WY	39
High Plains	WY	99
McFadden Ridge 1	WY	29
Pryor Mountain	WY	240
Rolling Hills	WY	99
Seven Mile Hill	WY	99
Seven Mile Hill II	WY	20
TB Flats 1-2	WY	500
Foote Creek II-IV	WY	43
Rock Creek I	WY	190
Rock Creek II	WY	400
Rock River	WY	50
TOTAL – Owned Wind		**2,937**

Table 6.5 – Non-Owned Wind Resources

Power Purchase Agreements	State	PPA or QF	Capacity (MW)
Wolverine Creek	ID	PPA	65
Chopin-Schumann	WA	QF	8
Cedar Springs I	WY	PPA	199
Cedar Springs III	WY	PPA	133
Three Buttes Power	WY	PPA	99
Top of the World	WY	PPA	200
Meadow Creek Project Five Pine	ID	QF	40
Meadow Creek Project North Point	ID	QF	80
Latigo	UT	QF	60
Mountain Wind I	UT	QF	61
Mountain Wind II	UT	QF	80
Power County Park North	UT	QF	23
Power County Park South	UT	QF	23
Spanish Fork Park 2	UT	QF	19

Tooele 1 and 2	UT	QF	3
Big Top	WA	QF	2
Butter Creek Power	WA	QF	5
Chopin	WA	QF	10
Four Corners	WA	QF	8
Four Mile Canyon	WA	QF	10
Orchard 1	WA	QF	10
Orchard 2	WA	QF	10
Orchard 3	WA	QF	10
Orchard 4	WA	QF	10
Oregon Trail	WA	QF	10
Pacific Canyon	WA	QF	8
Sand Ranch	WA	QF	10
Three Mile Canyon	WA	QF	8
Wagon Trail	WA	QF	3
Ward Butte	WA	QF	7
BLM Rawlins	WY	QF	0.1
Pioneer Park I	WY	QF	80
Cedar Creek	ID	PPA	152
Anticline	WY	PPA	101
Boswell	WY	PPA	320
Cedar Springs IV	WY	PPA	350
TOTAL – Purchased Wind			**2217**

Solar

PacifiCorp has a total of 97 solar projects under contract representing 3,615 MW of nameplate capacity. Of these, two recently signed solar resources also include a total of 550 MW of battery storage. Table 6.6 list solar power purchase agreements, and through Table 6.7 through Table 6.9 list solar qualifying facilities for each relevant state.

Table 6.6 – Solar Power Purchase Agreements

Power Purchase Agreements			
Resource	**State**	**Solar Capacity (MW)**	**Storage Capacity (MW)**
Black Cap	OR	2	-
Millican	OR	60	-
Old Mill	OR	5	-
Oregon Solar Incentive Project	OR	9	-
Prineville	OR	40	-
Appaloosa Solar IA	UT	120	-
Appaloosa Solar IB	UT	80	-
Castle Solar (Retail 1)	UT	20	-
Castle Solar (Retail 2)	UT	20	-
Cove Mountain	UT	58	-
Cove Mountain II	UT	122	-
Elektron Solar 20Yr	UT	10	-
Elektron Solar 25Yr	UT	70	-
Faraday	UT	525	150
Graphite	UT	80	-
Green River	UT	400	400
Hornshadow Solar I	UT	100	-
Hornshadow Solar II	UT	200	-
Horseshoe	UT	75	-
Hunter	UT	100	-
Milford	UT	99	-
Pavant III	UT	20	-
Rocket	UT	80	-
Sigurd	UT	80	-
TOTAL – Power Purchase Agreements		**2375**	**550**

Table 6.7 – Solar Qualifying Facilities, Oregon

Oregon Qualifying Facilities		
Resource	**Solar Capacity (MW)**	**Storage Capacity (MW)**
7 Mile Solar	1	-
Adams	10	-
Antelope Creek Solar	2	-
Bear Creek	10	-
Black Cap II	8	-
Blackwell Creek Solar*	1	-
Bly	8	-
Buckaroo Solar 1*	3	-
Buckaroo Solar 2*	3	-
Canyonville Solar 1*	1	-
Canyonville Solar 2*	2	-
Chapman Creek Solar*	3	-
Cherry Creek Solar*	0.4	-
Chiloquin Solar	10	-
Elbe	10	-
Goodling Community Solar*	1	-
Green Solar*	3	-
Hay Creek Solar*	0.6	-
Klamath Falls Solar 1	0.8	-
Klamath Falls Solar 2	3	-
Linkville Solar*	3	-
Merrill	10	-
Norwest Energy 2 (Neff)	10	-
Norwest Energy 4 (Bonanza)	6	-
Norwest Energy 7 (Eagle Point)	10	-
Norwest Energy 9 Pendleton	6	-
OR Solar 2, LLC (Agate Bay)	10	-
OR Solar 3, LLC (Turkey Hill)	10	-
OR Solar 6, LLC (Lakeview)	10	-
OR Solar 8, LLC (Dairy)	10	-
Orchard Knob Solar	2	-
OSLH Collier	10	-
Pilot Rock Solar 1*	3	-
Pilot Rock Solar 2*	3	-
Pine Grove Solar	1	-
Round Lake Solar	1	-
Skysol	55	-
Solorize Rogue*	0.1	-
Sunset Ridge Solar	2	-
Tumbleweed	10	-
Tutuilla Solar*	2	-
Wallowa County*	0.4	-
Whisky Creek Solar*	0.2	-
Wocus Marsh Solar*	0.9	-
Wood River Solar*	0.4	-
Woodline Solar	8	-
TOTAL – Oregon Solar QF Resources	**264**	**0**

*New project added in 2025 IRP

Table 6.8 – Solar Qualifying Facilities, Utah

Utah Qualifying Facilities		
Resource	**Solar Capacity (MW)**	**Storage Capacity (MW)**
Beryl	3	-
Buckhorn	3	-
CedarValley	3	-
Enterprise	80	-
Escalante I	80	-
Escalante II	80	-
Escalante III	80	-
Ewauna	1	-
Ewauna II	3	-
Granite Mountain - East	80	-
Granite Mountain - West	50	-
GranitePeak	3	-
Greenville	2	-
Iron Springs	80	-
Laho	3	-
Milford 2	3	-
Milford Flat	3	-
Pavant	50	-
Pavant II	50	-
Quichapa I	3	-
Quichapa II	3	-
Quichapa III	3	-
Red Hill	80	-
South Milford	3	-
SunE1	3	-
SunE2	3	-
SunE3	3	-
Three Peaks	80	-
TOTAL – Utah Solar QF Resources	**838**	**0**

Table 6.9 – Solar Qualifying Facilities, Wyoming

Wyoming Qualifying Facilities		
Resource	**Solar Capacity (MW)**	**Storage Capacity (MW)**
Sage I	20	-
Sage II	20	-
Sage III	18	-
Sweetwater	80	-
TOTAL – Wyoming Solar QF Resources	**138**	**0**

Geothermal

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

Biomass/Biogas

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

Distributed Generation Resources

Table 6.10 provides a breakdown of distributed generation capacity and customer counts from data collected as of March 31, 2024. In addition to resources, PacifiCorp's customers also have over 60 MW of battery storage capacity. For forecasted growth in distributed generation and storage, please refer to Volume II, Appendix L (Distributed Generation Study).

Table 6.10 – Distributed generation Customers and Capacity

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

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

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

Energy Storage

In addition to the battery storage contracted with solar resources listed in Table 6.6 PacifiCorp has existing or committed battery storage projects totaling approximately 523 MW of nameplate capacity, as shown in Table 6.11.

Table 6.11 – Storage Resources

Power Purchase Agreements / Exchanges	State	Technology	Capacity (MW)
Dominguez Storage*	UT	Battery	200
Enterprise*	UT	Battery	80
Escalante*	UT	Battery	80
Granite Mountain*	UT	Battery	80
Iron Springs*	UT	Battery	80
Panguitch	UT	Battery	1
Oregon Institute of Technology (OIT)	OR	Battery	2
TOTAL – Purchased Battery			**523**

*New project added in 2025 IRP

Hydroelectric Generation

PacifiCorp owns or purchases over 1,200 MW of hydroelectric generation capacity. In addition to being non-emitting generation sources hydro resources provide various operational benefits that can include flexible generation, spinning reserves, and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

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

Table 6.12 – PacifiCorp Hydroelectric Generation Facilities

Plant	River System	State	Capacity (MW)
East - Owned			
Cutler	Bear	UT	29
Grace	Bear	UT	33
Oneida	Bear	UT	27.9
Soda	Bear	UT	14
Small East [1/]	Other	UT	20.5
West - Owned			
Bend	Other	OR	1
Big Fork	Other	MT	4.6
Swift 1 [2/]	Lewis	WA	263.6
Yale	Lewis	WA	163.6
Merwin	Lewis	WA	151
Clearwater 1	N. Umpqua	OR	17.9
Clearwater 2	N. Umpqua	OR	31
Fish Creek	N. Umpqua	OR	10.4
Lemolo 1	N. Umpqua	OR	32
Lemolo 2	N. Umpqua	OR	38.5
Slide Creek	N. Umpqua	OR	18
Soda Springs	N. Umpqua	OR	11.6
Toketee	N. Umpqua	OR	45
Eagle Point	Rogue	OR	2.8
Prospect 1	Rogue	OR	4.6
Prospect 2	Rogue	OR	36
Prospect 3	Rogue	OR	7.7
Prospect 4	Rogue	OR	0.9
Fall Creek	Other	OR	2
Wallowa Falls	Other	OR	1.1
		Total Owned	**968**
Qualifying Facilities (QF)			
QF	Various	CA	9.4
QF	Various	ID	22.7
QF	Various	OR	40
QF	Various	UT	2.2
QF	Various	WA	2.9
Mid-Columbia	Columbia	WA	170
		Total QF	**247**
Total Hydroelectric			**1215**

[1/] Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Veyo, Sand Cove, Viva Naughton, and Gunlock.

[2/] Cowlitz County PUD owns Swift No. 2, and is operated in coordination with other Lewis River projects by PacifiCorp.

Demand-Side Management/Distributed Generation

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

- **Demand Response—Resources from fully dispatchable or scheduled firm capacity product offerings/programs:** Demand response programs are those for which capacity savings occur because of active company control or advanced scheduling. Once customers agree to participate in these programs, the timing and persistence of the load reduction is involuntary on their part within the agreed upon limits and parameters of the program. Modeling includes program drop-opt rate and event non-performance rate assumptions to account for program parameters. Program examples include residential and small commercial central air conditioner load control programs that are dispatchable, and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design or event noticing requirements). Savings are typically only sustained for the duration of the event and there may also be return energy associated with the program. These are considered Class 1 DSM resources.

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

- **Price Response and Load Shifting—Resources from price-responsive energy and capacity product offerings/programs:** Price response and load shifting programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. As a result of their voluntary nature, participation tends to be low and savings are less predictable, making these resources less suitable to incorporate into resource planning, at least until their size and customer behavior profile provide sufficient information needed to model and plan for a reliable and predictable impact. The impacts of these resources may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs. Savings are typically only sustained for the duration of the incentive offering and, in many cases, loads tend to be shifted rather than being avoided. These are considered Class 3 DSM resources.

- **Education and Information—Non-incented behavioral-based savings achieved through broad energy education and communication efforts:** Education and information programs promote reductions in energy or capacity usage through broad-based energy education and communication efforts. The program objectives are to help customers better understand how to manage their energy usage through no-cost actions such as conservative thermostat settings and turning off appliances, equipment, and lights when not in use. These programs are also used to increase customer awareness of additional actions they might take to save energy and the service and financial tools available to assist them. These programs help foster an understanding and appreciation of why utilities seek customer participation in other programs. Similar to price response and load shifting resources, the impacts of these programs may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include company brochures with energy savings tips, customer newsletters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs. These are considered Class 4 DSM resources.

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

Table 6.13 summarizes PacifiCorp's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental energy efficiency is determined as an outcome of resource portfolio modeling and is characterized as a new resource in the preferred portfolio, existing energy efficiency in Table 6.13 is shown as having zero MW.[1] Similarly, demand response resources available to the preferred portfolio, are characterized as incremental to Table 6.13. For a summary of current DSM program offerings in each state, refer to Volume II, Appendix D (Demand-Side Management Resources).

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

Table 6.13 – Existing DSM Resource Summary

Program	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2025-2045 Period
Demand Response	Residential/small commercial air conditioner load control	135 MW summer[1/]	Yes.
	Irrigation load management	200 MW summer	Yes.
	Interruptible contracts	136 MW summer	Yes.
	Wattsmart® Batteries	32 MW summer	Yes.
	Wattsmart® Business	45 MW summer	Yes.
Energy Efficiency	PacifiCorp and Energy Trust of Oregon programs	0 MW	No. Energy efficiency programs are modeled as resource options in the portfolio development process and included in the preferred portfolio.
Price Response and Load Shifting	Time-based pricing	Energy and capacity impacts are not available/measured	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	Energy and capacity impacts are not available/measured	No. Historical savings from customer response to pricing structure is reflected in load forecast.
Education and Information	Energy education	Energy and capacity impacts are not available/measured	No. Historical savings from customer participation are reflected in the load forecast.

[1/] A/C load control is based on long duration event characterization which assumes 50% cycling of ACs. A faster event (<1 hr) is characterized as 270 MW within the model.

Distributed Generation Forecast

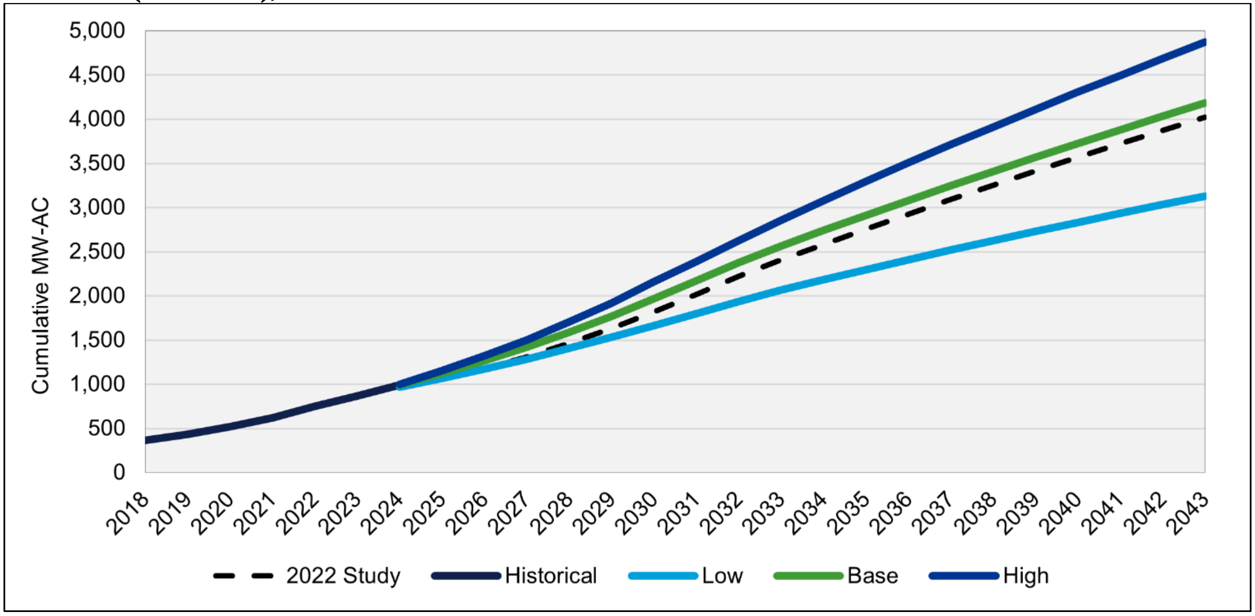
For the 2025 IRP, PacifiCorp contracted with DNV to update the assessment of distributed generation (DG)[2] penetration with new market, policy, and incentive developments.[3,4] The study provided a forecast of adoption of non-utility owned, behind-the-meter (BTM) customer generation resources in each of the six states served by PacifiCorp. Specific technologies studied included solar photovoltaic, photovoltaic solar coupled with battery storage, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines.

[2] In the 2023 IRP, this study was referred to as the "Private Generation" assessment.
[3] See Appendix L (Distributed Generation Study).
[4] PacifiCorp's and DNV's decisions in the development of the DG study were topics of discussion in the 2025 IRP public input meeting series and stakeholder feedback.
See Appendix M, stakeholder feedback form #6 (Renewable Northwest).
See Appendix M, stakeholder feedback form #17 (Oregon Public Utility Commission).
See Appendix M, stakeholder feedback form #26 (Vote Solar).

DNV estimates approximately 4.18 gigawatts (GW) of DG capacity will be installed in PacifiCorp's service area by 2043 in the base case scenario. As shown in Figure 6.1, the low and high scenarios project a cumulative installed capacity of 3.12 GW and 4.87 GW by 2043, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions. The Inflation Reduction Act of 2022 (IRA) extends tax credits for distributed generation that creates favorable economics for adoption and is incorporated into each case. The DNV study identifies expected levels of customer-sited DG, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes and informs customer cited demand response battery potential for the conservation potential assessment (CPA).

See Appendix L for the full DNV Distributed Generation report.

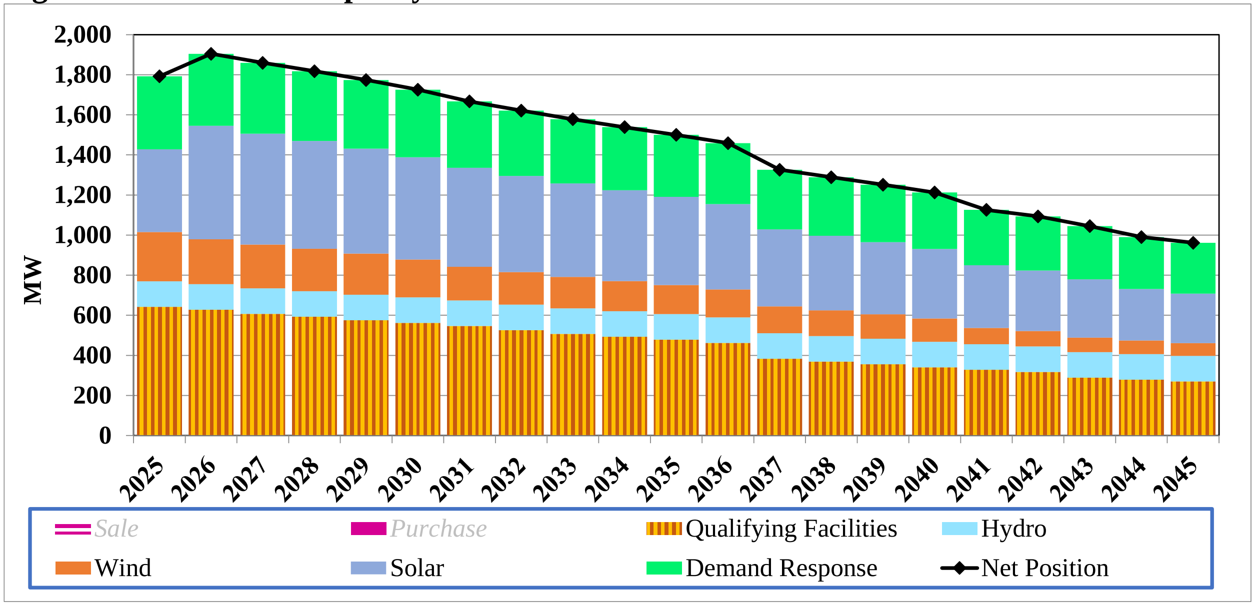
Figure 6.1 – Cumulative Historical and New Capacity Installed by Scenario (MW-AC), 2024-2043



Power-Purchase Agreements

PacifiCorp also meets capacity and energy requirements through long-term firm contracts. Figure 6.2 presents the contract capacity in place for 2025 through 2045. As shown, major capacity reductions in solar purchases, wind purchases, and QF contracts occur. For planning purposes, PacifiCorp assumes interruptible load contracts and demand response are extended through the end of the IRP study period. After their current contract terms, QF contracts are extended at a reduced level that reflects the historical renewal rate of 75%. All contracts are shown at their peak capacity contribution levels.

Figure 6.2 – Contract Capacity in the 2025 IRP Summer Load and Resource Balance



Capacity Load and Resource Balance

Capacity Balance Overview

The purpose of the load and resource balance is to compare annual obligations to the annual capability of PacifiCorp's existing resources after retirements and future energy efficiency savings from the 2025 IRP preferred portfolio, and without new generating resource additions.

The capacity balance compares generating capability to load obligations across both summer and winter. For the 2025 IRP, the load and resource balance reflects values from the Western Resource Adequacy Program (WRAP). WRAP calculates project-specific qualifying capacity contribution values for all existing and contracted resources, and those values are used where data is available. WRAP also provides the average contribution for wind, solar, energy storage and run of river hydro in different geographic areas, and these estimates are used for proxy resources in the 2025 IRP. WRAP will update the capacity contributions for resources ahead of each season, reflecting the current resource mix of the WRAP footprint through time. WRAP has also provided projections for future years and different resource penetration levels – as the penetration of wind, solar, and storage increases, contributions are expected to decline. Significant uncertainty remains, due to resource mix and timing, along with indirect factors like climate impacts on load and hydro. To better reflect future WRAP compliance requirements, PacifiCorp used the projections provided by WRAP to estimate contributions in 2045 based on the regional resource mix developed as part of the forward price curve used in the 2025 IRP. Because PacifiCorp is a relatively small portion of the regional resource mix, the calculation is static and does not vary with PacifiCorp's specific portfolio selections. WRAP contributions fall linearly from the current values for 2025 to the projected values for 2045. Additional detail is provided in Appendix K (Capacity Contribution).

Note – While Appendix K (Capacity Contribution) has not been completed for the Dec 31 distribution of the Draft 2025 IRP, the modeled WRAP contributions through time are available from postings for the IRP public input process:

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2025-irp/PacifiCorp_2025_IRP_PIM_September_25_2024_Supplemental.pdf

For reporting purposes, the capacity balance summarized in this chapter is developed by first reducing the hourly system load by hourly distributed generation projections to determine the net system coincident peak load for each of the first ten years (2025-2034) of the planning horizon. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are included as part of the existing resources. The annual resource deficit or surplus is then computed by multiplying the obligation by the planning reserve margin (14.4% for the 2025 IRP, reflecting the WRAP value for the month of July) and then subtracting the result from existing resources. This view is presented both without and with uncommitted Market purchases.

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

Load and Resource Balance Components

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

Under the calculations, there are negative values in the table in both the resource and obligation sections. This is consistent with how resource categories are represented in portfolio modeling. The resource categories include resources by type—coal, gas, hydroelectric, wind, solar, other renewables, storage, QFs, demand response, and purchases. Categories in the obligation section include load, distributed generation, and energy efficiency from the preferred portfolio.

Demand Response

Existing demand response program capacity is categorized as a resource. Under WRAP, demand response must be designated as either a load reduction, where any impacts are captured in peak loads, or as a resource, based on its availability and duration during peak conditions. For the 2025 IRP, demand response is used for operating reserves and dispatched within the PLEXOS model based on economics and need, and is not targeted to reduce summer-time peak loads which often occur during solar generation hours when net demand is lower. As a result, treatment as a resource provides a larger capacity benefit at this time. PacifiCorp expects to continue evaluating this as the WRAP gets underway, as some demand response programs may be suitable for peak load reduction. Also included in the demand response category are interruptible contracts. PacifiCorp has had interruptible contracts with large load customers for many years. These contracts are a key aspect of the retail service provided to the associated customers, and absent these contracts their demand would likely be different from that included in the load forecast. To maintain an alignment with the load forecast, these contracts are assumed to continue indefinitely under their current structure.

Obligation

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

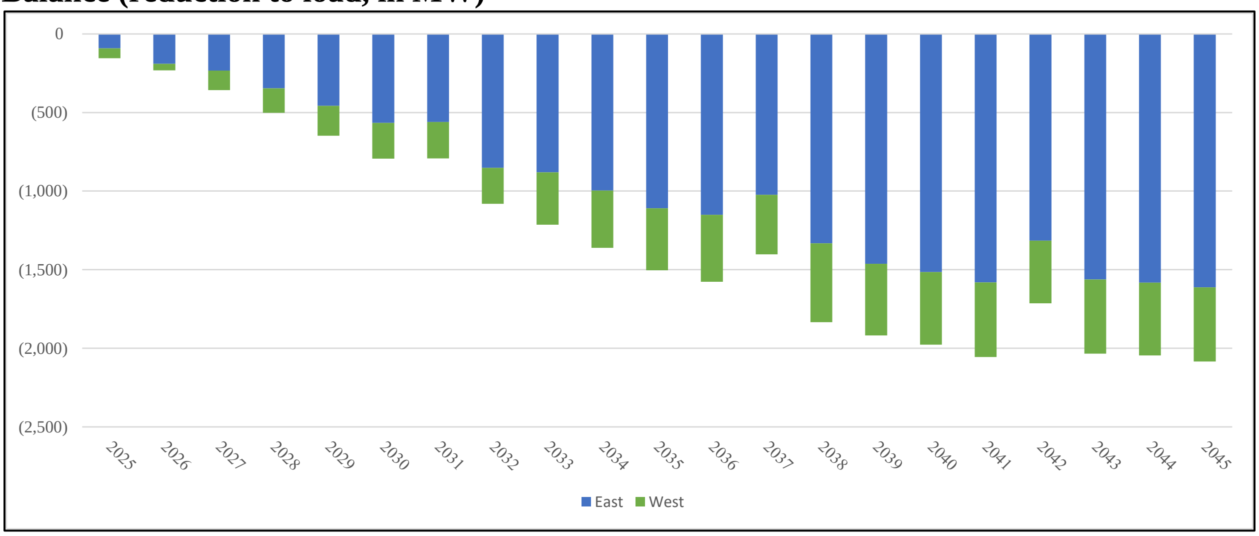
Load Net of Distributed generation

The largest component of the obligation is retail load. In the 2025 IRP, the hourly retail load at a location is first reduced by hourly distributed generation at the same location. The system coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year and season. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks.

Energy Efficiency

An adjustment is made to load to remove the projected embedded energy efficiency as a reduction to load. Due to timing issues with the vintage of the load forecast, there is a level of 2024 energy efficiency that is not incorporated in the forecast. The 2024 energy efficiency forecast has been added to the energy efficiency line along with the energy efficiency selected in the 2025 IRP preferred portfolio. Figure 6.3 shows the energy efficiency for the east and west control areas in the 2025 IRP preferred portfolio.

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



Planning Reserve Margin

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

Position

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

Capacity Balance Determination

Methodology

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

> **Existing Resources** = Coal + Gas + Hydro + Renewable + Storage + Firm Purchases + Qualifying Facilities + Demand Response

The peak load, distributed generation, 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 – Distributed generation – Energy Efficiency

The level of reserves to be added to the obligation is then calculated. This is accomplished by taking the net system obligation calculated above multiplied by the 14.4 percent PRM for July and 16.8 percent PRM for December adopted from WRAP for the 2025 IRP. The formula for this calculation is:

> **Planning Reserves** = Obligation x PRM

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

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

Capacity Balance Results

Table 6.14 and Table 6.15 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target PRM of 14.4 percent in the summer and 16.8 percent in the winter to calculate the planning reserve amount.[5] Balances for PacifiCorp's system as well as the east and west control areas are shown. While east and west control area balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis up to the limits of the transfer capability between the two areas. Also note that QF wind and solar projects listed earlier in the chapter are reported under the QF line item rather than the renewables line item.

[5] PacifiCorp acknowledged errors in its 2023 IRP load and resource balance, which have been addressed in the 2025 IRP. See Appendix M, stakeholder feedback form #12 (Utah Association of Energy Users).

Table 6.14 -- Summer Peak – System Capacity Loads and Resources without Resource Additions

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	3,959	3,567	3,567	3,375	3,090	2,926	2,926	2,926	2,926	2,926
Gas	2,984	3,294	3,294	3,295	3,469	3,470	3,470	3,470	3,470	3,470
Hydroelectric	76	76	76	76	76	76	76	76	76	76
Wind	246	224	218	211	205	189	168	162	157	151
Solar	342	499	488	476	464	453	441	429	418	406
Other Renewable	46	45	44	42	41	40	38	37	36	34
Storage	1	939	925	909	894	879	865	849	834	819
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	413	404	395	386	377	368	359	348	334	323
Demand Response	305	300	295	290	286	281	276	271	266	262
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	0	(639)	(685)	(308)	0	0	0	0	0	0
East Existing Resources	**8,373**	**8,710**	**8,617**	**8,753**	**8,902**	**8,681**	**8,619**	**8,570**	**8,517**	**8,468**
Load	7,734	7,947	7,952	8,230	8,667	8,855	9,050	9,335	9,335	9,284
Distributed Generation	(157)	(143)	(186)	(234)	(285)	(341)	(400)	(458)	(515)	(354)
Energy Efficiency	(92)	(191)	(234)	(346)	(457)	(566)	(561)	(852)	(880)	(996)
East Total obligation	**7,485**	**7,613**	**7,532**	**7,651**	**7,924**	**7,948**	**8,089**	**8,025**	**7,940**	**7,934**
Planning Reserve Margin (14.4%)	1,078	1,096	1,085	1,102	1,141	1,144	1,165	1,156	1,143	1,142
East Obligation + Reserves	8,563	8,710	8,617	8,753	9,065	9,092	9,254	9,180	9,083	9,076
East Position	(190)	0	0	0	(164)	(412)	(635)	(610)	(566)	(608)
Available Market Purchases	500	500	500	500	500	0	0	0	0	0
West										
Coal	140	133	133	133	133	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712
Wind	0	0	0	0	0	0	0	0	0	0
Solar	69	67	65	62	60	58	52	50	48	46
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	1	1	1	1	1	1	1	1	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	229	224	212	207	198	194	188	178	174	170
Demand Response	60	59	58	58	57	56	55	55	54	53
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	0	639	685	308	0	0	0	0	0	0
West Existing Resources	**1,927**	**2,551**	**2,583**	**2,197**	**1,877**	**1,737**	**1,724**	**1,712**	**1,704**	**1,696**
Load	3,672	3,826	3,938	4,121	4,271	4,482	4,609	4,828	4,946	4,887
Distributed Generation	(49)	(54)	(75)	(99)	(124)	(152)	(182)	(213)	(244)	(148)
Energy Efficiency	(63)	(41)	(123)	(157)	(191)	(227)	(231)	(229)	(334)	(364)
West Total obligation	**3,560**	**3,731**	**3,740**	**3,866**	**3,955**	**4,102**	**4,195**	**4,386**	**4,368**	**4,376**
Planning Reserve Margin (14.4%)	513	537	539	557	570	591	604	632	629	630
West Obligation + Reserves	4,072	4,269	4,278	4,423	4,525	4,693	4,799	5,017	4,998	5,006
West Position	(2,145)	(1,718)	(1,695)	(2,226)	(2,648)	(2,956)	(3,075)	(3,306)	(3,293)	(3,309)
Available Market Purchases	2,603	2,603	2,603	2,603	2,603	0	0	0	0	0
System										
Total Resources	10,300	11,260	11,200	10,950	10,779	10,417	10,343	10,281	10,221	10,164
Obligation	11,045	11,345	11,272	11,517	11,879	12,050	12,284	12,410	12,308	12,310
Planning Reserves (14.4%)	1,590	1,634	1,623	1,658	1,711	1,735	1,769	1,787	1,772	1,773
Obligation + Reserves	12,635	12,978	12,895	13,175	13,590	13,785	14,053	14,197	14,081	14,082
System Position	(2,335)	(1,718)	(1,695)	(2,226)	(2,811)	(3,368)	(3,710)	(3,916)	(3,859)	(3,918)
Available Market Purchases	3,103	3,103	3,103	3,103	3,103	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	2,335	1,718	1,695	2,226	2,811	0	0	0	0	0
Net Surplus/(Deficit)	0	0	0	0	0	(3,368)	(3,710)	(3,916)	(3,859)	(3,918)

Table 6.14 (cont.) – Summer Peak System Capacity Loads and Resources without Resource Additions

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926
Gas	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470
Hydroelectric	76	76	76	76	76	76	76	76	76	76	76
Wind	145	140	134	128	122	117	81	77	73	69	65
Solar	395	383	343	332	322	311	300	290	279	246	236
Other Renewable	33	32	30	11	11	10	9	9	8	8	0
Storage	804	788	773	759	744	728	714	699	684	668	654
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	314	302	240	231	223	211	204	196	189	182	176
Demand Response	257	252	247	243	238	233	228	223	218	214	209
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,420**	**8,370**	**8,240**	**8,177**	**8,131**	**8,083**	**8,009**	**7,966**	**7,924**	**7,860**	**7,812**
Load	9,411	9,557	9,767	9,935	10,083	10,201	10,339	10,480	10,664	10,745	10,883
Distributed Generation	(385)	(415)	(445)	(474)	(503)	(529)	(557)	(584)	(609)	(635)	(660)
Energy Efficiency	(1,110)	(1,151)	(1,024)	(1,333)	(1,462)	(1,515)	(1,580)	(1,315)	(1,562)	(1,583)	(1,613)
East Total obligation	**7,916**	**7,990**	**8,298**	**8,129**	**8,118**	**8,156**	**8,202**	**8,581**	**8,492**	**8,528**	**8,610**
Planning Reserve Margin (14.4%)	1,140	1,151	1,195	1,171	1,169	1,175	1,181	1,236	1,223	1,228	1,240
East Obligation + Reserves	9,056	9,141	9,493	9,299	9,287	9,331	9,383	9,817	9,715	9,756	9,850
East Position	(636)	(771)	(1,253)	(1,122)	(1,156)	(1,248)	(1,374)	(1,851)	(1,791)	(1,896)	(2,038)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712	712
Wind	0	0	0	0	0	0	0	0	0	0	0
Solar	45	43	41	39	37	35	13	12	11	11	10
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	165	160	143	138	133	129	125	121	100	96	94
Demand Response	52	52	51	50	49	49	48	47	46	46	45
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0	0	0
West Existing Resources	**1,689**	**1,681**	**1,662**	**1,655**	**1,647**	**1,640**	**1,613**	**1,608**	**1,585**	**1,580**	**1,576**
Load	4,944	5,009	5,082	5,189	5,258	5,330	5,397	5,473	5,660	5,651	5,730
Distributed Generation	(163)	(177)	(192)	(206)	(221)	(234)	(249)	(263)	(277)	(290)	(304)
New Energy Efficiency	(394)	(426)	(378)	(502)	(457)	(461)	(475)	(399)	(473)	(463)	(471)
West Total obligation	**4,388**	**4,406**	**4,512**	**4,481**	**4,581**	**4,635**	**4,674**	**4,812**	**4,910**	**4,897**	**4,955**
Planning Reserve Margin (14.4%)	632	634	650	645	660	667	673	693	707	705	713
West Obligation + Reserves	5,020	5,040	5,161	5,127	5,240	5,303	5,347	5,505	5,618	5,603	5,668
West Position	(3,330)	(3,359)	(3,499)	(3,472)	(3,594)	(3,662)	(3,734)	(3,897)	(4,032)	(4,023)	(4,092)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
System											
Total Resources	10,109	10,051	9,902	9,831	9,778	9,723	9,622	9,574	9,509	9,439	9,388
Obligation	12,304	12,396	12,810	12,610	12,699	12,791	12,876	13,393	13,403	13,425	13,564
Planning Reserves (14.4%)	1,772	1,785	1,845	1,816	1,829	1,842	1,854	1,929	1,930	1,933	1,953
Obligation + Reserves	14,076	14,181	14,654	14,426	14,528	14,633	14,730	15,321	15,333	15,358	15,518
System Position	(3,967)	(4,130)	(4,752)	(4,594)	(4,750)	(4,910)	(5,108)	(5,748)	(5,824)	(5,919)	(6,129)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	(3,967)	(4,130)	(4,752)	(4,594)	(4,750)	(4,910)	(5,108)	(5,748)	(5,824)	(5,919)	(6,129)

Table 6.15 – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	4,147	3,733	3,733	3,498	3,184	3,014	3,014	3,015	3,015	3,015
Gas	3,003	3,334	3,334	3,335	3,526	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33
Wind	2,037	1,929	1,836	1,748	1,616	1,456	1,377	1,300	1,226	1,154
Solar	77	104	101	98	95	92	89	86	83	80
Other Renewable	41	39	38	37	35	34	33	31	30	28
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	186	181	177	171	167	162	155	150	130	125
Demand Response	139	135	132	129	125	122	119	116	112	109
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,600)	(1,600)	(1,256)	(1,075)	(803)	(530)	(445)	(255)
East Existing Resources	**8,062**	**7,890**	**7,785**	**7,449**	**7,525**	**7,366**	**7,544**	**7,728**	**7,711**	**7,817**
Load	5,724	6,099	6,174	6,448	6,759	6,698	6,869	7,153	7,223	7,397
Distributed Generation	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Energy Efficiency	(63)	(116)	(174)	(243)	(311)	(385)	(403)	(528)	(613)	(695)
East Total obligation	**5,659**	**5,981**	**5,997**	**6,201**	**6,443**	**6,306**	**6,459**	**6,617**	**6,601**	**6,693**
Planning Reserve Margin (16.8%)	951	1,005	1,007	1,042	1,082	1,059	1,085	1,112	1,109	1,124
East Obligation + Reserves	6,610	6,986	7,004	7,242	7,525	7,366	7,544	7,728	7,711	7,817
East Position	1,452	904	781	206	0	0	0	0	0	0
Available Market Purchases	500	500	500	500	500	0	0	0	0	0
West										
Coal	147	147	147	147	147	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726
Wind	64	61	59	57	54	52	50	47	45	43
Solar	1	1	1	1	1	1	0	0	0	0
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	68	68	60	60	57	56	56	55	55	55
Demand Response	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	1,600	1,600	1,600	1,600	1,256	1,075	803	530	445	255
West Existing Resources	**3,341**	**3,339**	**3,329**	**3,326**	**2,978**	**2,645**	**2,370**	**2,094**	**2,007**	**1,814**
Load	3,711	3,577	3,676	3,859	4,025	4,478	4,541	4,421	4,477	4,526
Distributed Generation	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Energy Efficiency	(45)	(79)	(118)	(157)	(199)	(246)	(236)	(328)	(370)	(407)
West Total obligation	**3,665**	**3,498**	**3,558**	**3,701**	**3,825**	**4,230**	**4,303**	**4,091**	**4,105**	**4,117**
Planning Reserve Margin (16.8%)	616	588	598	622	643	711	723	687	690	692
West Obligation + Reserves	4,281	4,086	4,156	4,322	4,467	4,941	5,026	4,778	4,794	4,809
West Position	(939)	(747)	(827)	(996)	(1,490)	(2,296)	(2,656)	(2,684)	(2,788)	(2,995)
Available Market Purchases	2,603	2,603	2,603	2,603	2,603	0	0	0	0	0
System										
Total Resources	11,404	11,229	11,114	10,775	10,503	10,011	9,914	9,822	9,717	9,631
Obligation	9,324	9,479	9,555	9,902	10,268	10,537	10,762	10,708	10,706	10,810
Planning Reserves (16.8%)	1,343	1,365	1,376	1,426	1,479	1,517	1,550	1,542	1,542	1,557
Obligation + Reserves	10,667	10,844	10,931	11,327	11,746	12,054	12,312	12,250	12,248	12,366
System Position	737	384	183	(552)	(1,243)	(2,043)	(2,398)	(2,427)	(2,531)	(2,735)
Available Market Purchases	3,103	3,103	3,103	3,103	3,103	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	552	1,243	0	0	0	0	0
Net Surplus/(Deficit)	737	384	183	0	0	(2,043)	(2,398)	(2,427)	(2,531)	(2,735)

Table 6.15 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015
Gas	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33	33
Wind	1,082	1,014	948	883	820	674	621	570	522	474	429
Solar	77	74	71	68	66	63	60	57	46	44	41
Other Renewable	27	26	24	8	8	8	7	6	6	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	121	103	98	95	91	87	83	79	75	72	68
Demand Response	106	103	99	96	93	89	86	83	80	76	73
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers											
East Existing Resources	**7,988**	**7,896**	**7,816**	**7,725**	**7,652**	**7,496**	**7,431**	**7,370**	**7,304**	**7,240**	**7,186**
Load	7,321	7,508	7,595	7,732	7,856	7,991	8,169	8,340	8,450	8,525	8,664
Distributed Generation	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(16)
Energy Efficiency	(580)	(891)	(834)	(824)	(879)	(926)	(1,042)	(979)	(1,305)	(1,268)	(1,195)
East Total obligation	**6,730**	**6,606**	**6,749**	**6,896**	**6,964**	**7,052**	**7,113**	**7,347**	**7,131**	**7,242**	**7,453**
Planning Reserve Margin (16.8%)	969	951	972	993	1,003	1,015	1,024	1,058	1,027	1,043	1,073
East Obligation + Reserves	7,699	7,557	7,721	7,889	7,966	8,067	8,137	8,405	8,158	8,285	8,526
East Position	289	338	95	(164)	(314)	(571)	(706)	(1,035)	(854)	(1,045)	(1,340)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726	726
Wind	41	39	36	34	32	30	28	26	24	22	20
Solar	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	53	53	52	51	51	50	50	49	49	49
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0	0	0
West Existing Resources	**1,556**	**1,552**	**1,550**	**1,547**	**1,544**	**1,542**	**1,539**	**1,536**	**1,534**	**1,532**	**1,529**
Load	4,773	4,920	4,989	4,941	5,062	5,136	5,276	5,289	5,398	5,345	5,467
Distributed Generation	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Energy Efficiency	(642)	(543)	(439)	(755)	(796)	(837)	(919)	(614)	(645)	(538)	(658)
West Total obligation	**4,128**	**4,374**	**4,548**	**4,183**	**4,263**	**4,297**	**4,353**	**4,671**	**4,749**	**4,803**	**4,805**
Planning Reserve Margin (16.8%)	694	735	764	703	716	722	731	785	798	807	807
West Obligation + Reserves	4,822	5,109	5,312	4,886	4,979	5,018	5,085	5,456	5,547	5,610	5,613
West Position	(3,265)	(3,557)	(3,762)	(3,338)	(3,435)	(3,477)	(3,546)	(3,920)	(4,013)	(4,079)	(4,083)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
System											
Total Resources	9,545	9,448	9,366	9,272	9,196	9,038	8,970	8,907	8,838	8,772	8,716
Obligation	10,858	10,980	11,297	11,079	11,227	11,348	11,466	12,018	11,880	12,045	12,258
Planning Reserves (16.8%)	1,564	1,581	1,627	1,595	1,617	1,634	1,651	1,731	1,711	1,735	1,765
Obligation + Reserves	12,422	12,561	12,924	12,674	12,843	12,983	13,117	13,749	13,591	13,780	14,023
System Position	(2,877)	(3,113)	(3,558)	(3,402)	(3,647)	(3,945)	(4,148)	(4,842)	(4,753)	(5,008)	(5,308)
Available Market Purchases	0	0	0	0	0	0	0	0	0	0	0
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	(2,877)	(3,113)	(3,558)	(3,402)	(3,647)	(3,945)	(4,148)	(4,842)	(4,753)	(5,008)	(5,308)

Figure 6.4 through Figure 6.7 are graphic representations of the above tables for annual capacity position for the summer system, winter system, east control area, and west control area. Also shown in the system capacity position graph are available Market purchases, which can be used to meet capacity needs. The market availability assumptions used for portfolio modeling are discussed further in Chapter 7.

Figure 6.4 – Summer System Capacity Position Trend

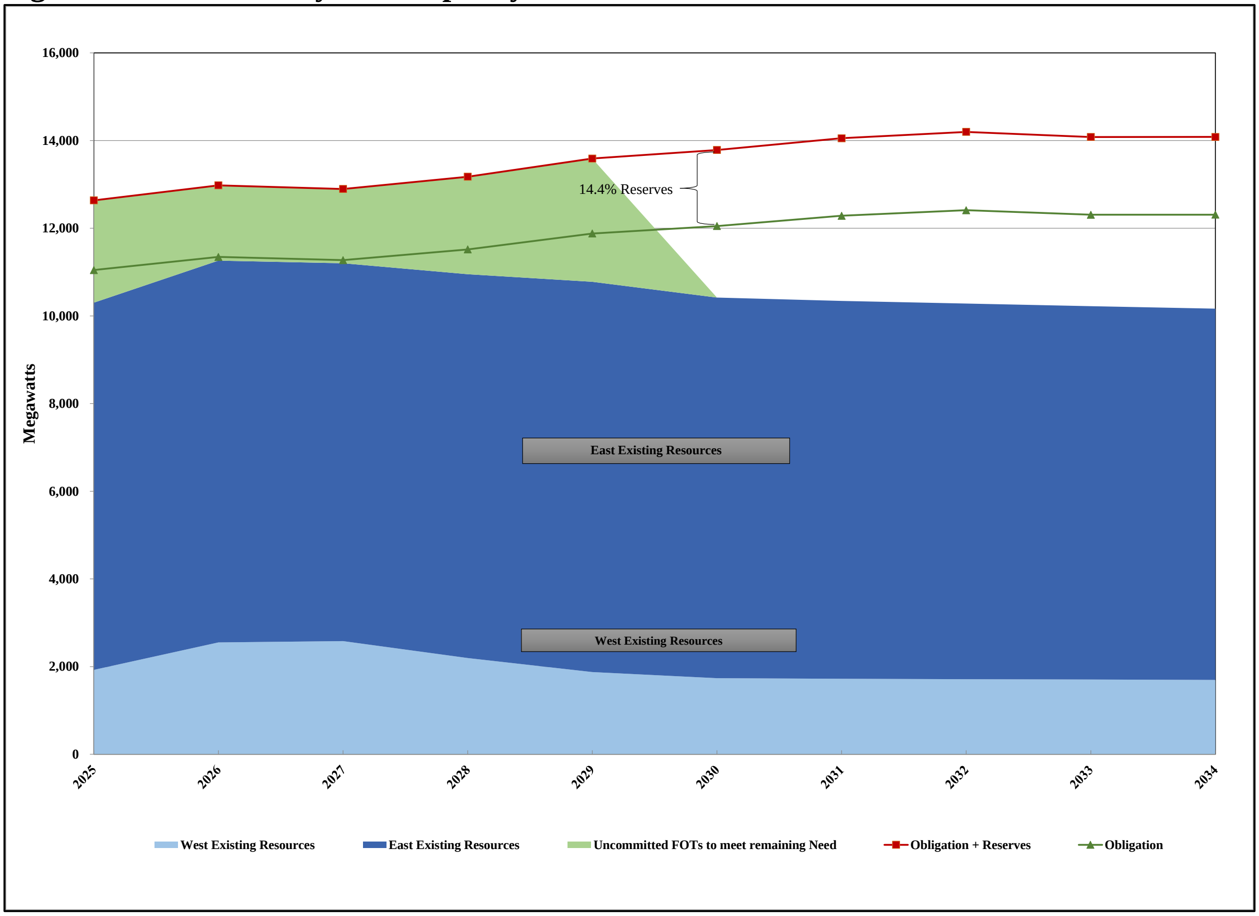


Figure 6.5 – Winter System Capacity Position Trend

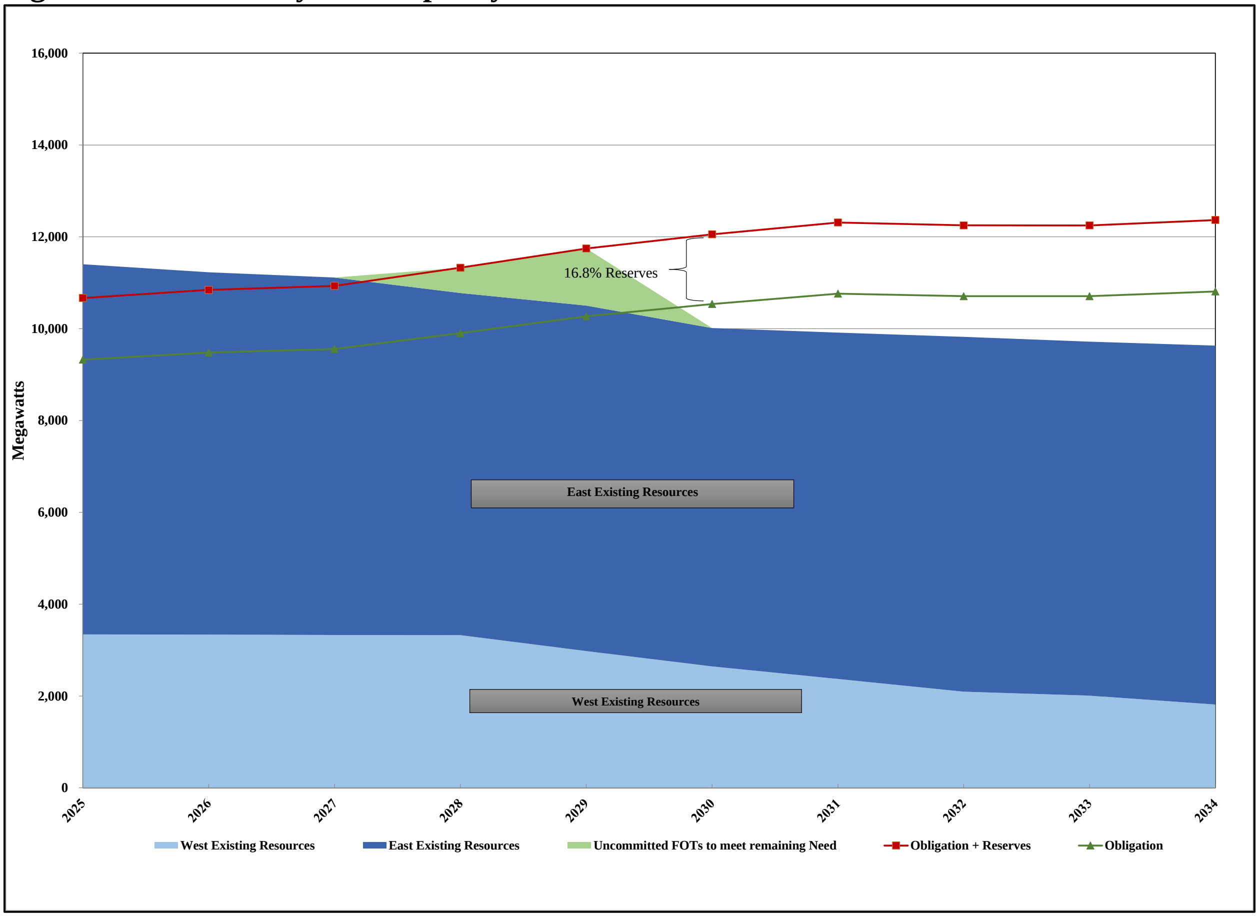


Figure 6.6 – East Summer Capacity Position Trend

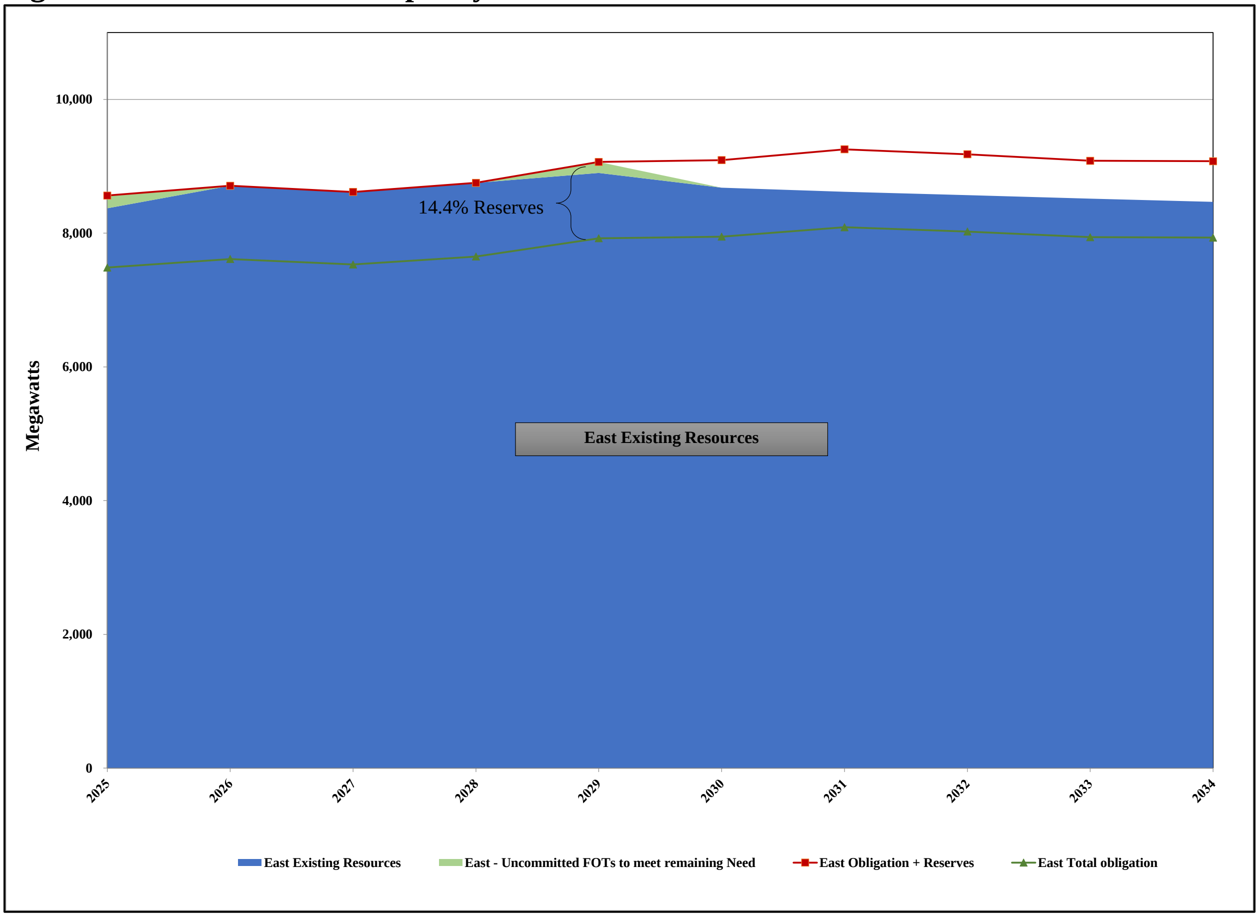
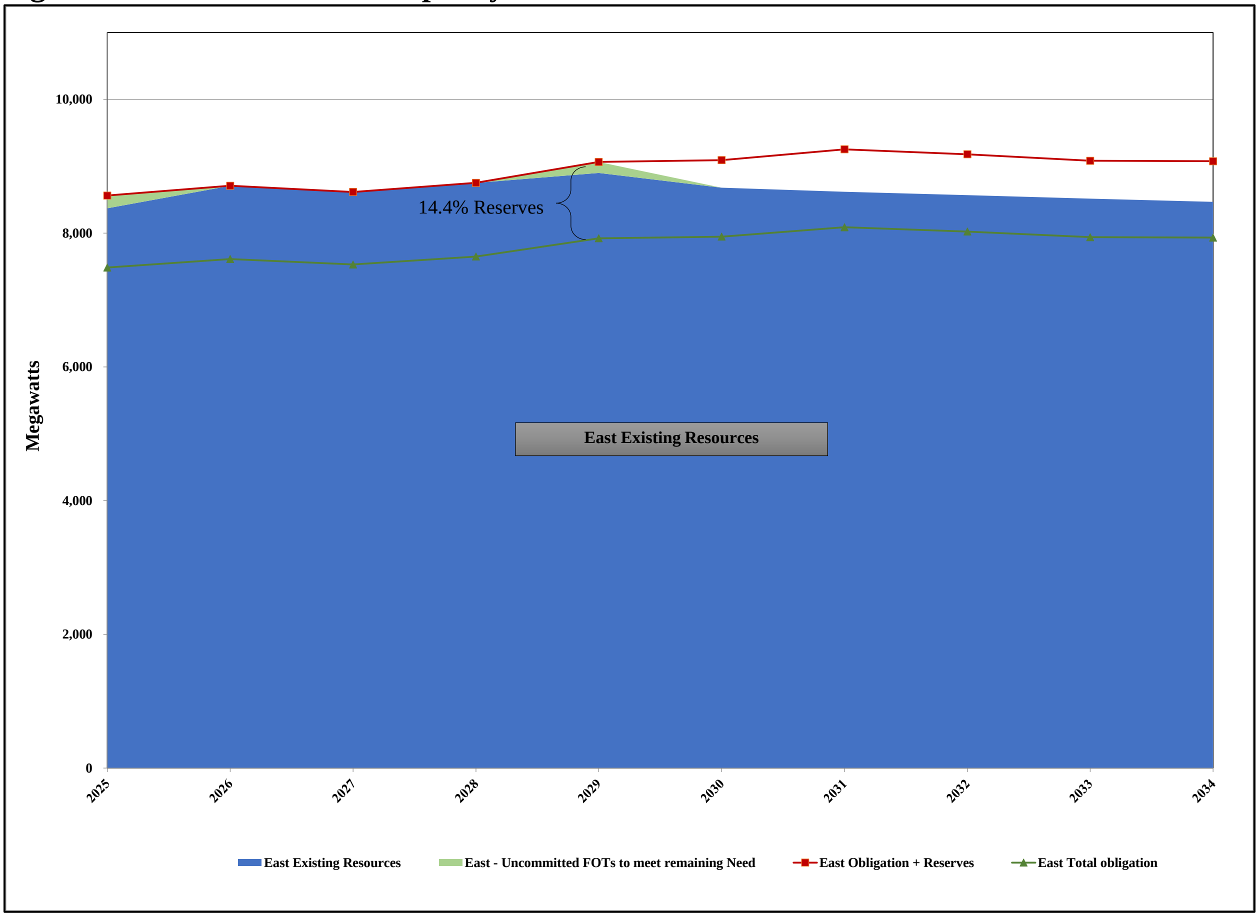


Figure 6.7 – West Summer Capacity Position Trend



CHAPTER 7 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp's resource attributes and costs for future generation resource options reflect updated information, based on assumptions from the National Renewable Energy Laboratory's 2024 Annual Technology Baseline to the extent data was available.[1]
- In addition to utility-scale resources (generally 200 megawatts (MW) or more), the 2025 IRP includes small-scale (20 MW) wind, solar, and biodiesel peaking options. These small-scale resource options are assumed to be sited in relative proximity to load, such that they do not require significant transmission system upgrades.
- Renewable resource generation profiles have been updated and expanded to include more proxy resource locations as well as distinct profiles for utility-scale and small-scale wind resources, rather than one generation profile per state as in the 2023 IRP. This update extends to online and contracted resources, as well as proxy resource options, and also includes expanded historical data for use with stochastic analysis.
- Options for utility-scale lithium-ion batteries (20 MW and 200 MW options), gravity energy storage systems, pumped hydro energy storage (PHES), thermal energy storage, one-hundred-hour iron-air storage, and adiabatic compressed air energy storage are included in this IRP. In a change from prior IRPs, hydrogen peaking resources are also treated as storage resources (rather than using pipelines and a market price for hydrogen). Hydrogen is electrolyzed using excess generation output and stored in either high-pressure tanks or underground caverns.
- The Plexos model endogenously models transmission upgrades, allowing for increases to transfer limits and resource interconnection. Where applicable, upgrades are restricted until all pre-requisites are in place.
- PacifiCorp continues to apply cost reduction credits to energy efficiency, reflecting risk mitigation benefits, transmission and distribution investment deferral benefits, and a ten percent market price credit for Washington and Oregon as allowed by the Northwest Power Act.

Introduction

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

Supply-Side Resources (SSR)

The list of supply-side resource options reflects the expected realities evidenced through external studies, internally generated studies, permitting, regulatory requirements, and stakeholder input. The process began with the list of major generating resources from the 2023 IRP. This resource

[1] https://atb.nrel.gov/electricity/2024/index

list was reviewed and modified to reflect stakeholder input, new technology developments, environmental factors, cost dynamics and anticipated permitting requirements. The National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[2] was used as much as possible to maintain consistency. Some of the terminology used in this chapter is from the ATB. A glossary of some of the terminology is provided below in Table 7.12 and a list of acronyms is provided in Table 7.13.

The SSR options include the following technologies grouped by energy source. More information about each technology is provided in the "Resource Option Descriptions" section of this chapter. The terminology here matches that used in the SSR Table, although some may have been shortened per the acronym list in Table 7.13.

- Natural Gas
    - Internal Combustion Engines
    - SCCT, Aero, & F-Frame
    - CCCT, 1x1, & 2x1
        - Adjustments for 95% Carbon Capture
        - Adjustments for Brownfield Construction
        - Adjustments for advanced technology innovation scenario ("Innovations far from market-ready today are successful and become widespread in the market. New technology architectures could look different from those observed today. Public and private R&D investment increases. For biopower technologies, technology cost designations appearing in ATB tables and figures refer to technology assumptions and the range of fuel price projections as described on their respective technology pages."[3])
- Hydrogen
    - Adjustments for 100% Hydrogen burning capability
    - Adjustments for Hydrogen Storage
    - Electrolyzer
- Coal, Carbon Capture Retrofits at existing plants. Note that although the common abbreviation for carbon capture and storage (CCS) is used, data for these resources does not include sequestration.
- Energy Storage
    - Lithium-Ion Batteries (20 MW, 200 MW, and 1,000 MW all with 4-hour duration)
        - Adjustments for double duration (i.e., 8-hour duration)
        - Adjustments for co-location with other generating resources
        - Adjustments for advanced technology innovation scenario
    - Gravity Batteries
    - Adiabatic Compressed Air Energy Storage (ACAES)
    - 100-Hour Iron Air Batteries
    - PHES (single and double reservoirs)
    - Pumped Thermal
- Solar
    - Adjustments for advanced technology innovation scenario
- Wind (various on-shore wind classes and off-shore class 12, as appropriate for PacifiCorp's service area)

[2] https://atb.nrel.gov/electricity/2024/definitions#scenarios
[3] https://atb.nrel.gov/electricity/2024/definitions#scenarios

  - Adjustments for advanced technology innovation scenario
- Nuclear[4]
  - Small Modular Reactor
    - Adjustments for adding thermal energy storage
  - Large Light Water Reactor
    - Adjustments for advanced technology innovation scenario (in addition to the earlier definition: "for nuclear technologies, technology cost designations appearing in ATB tables and figures refer to technology assumptions and the range of fuel price projections as described on their respective technology pages.")
- Geothermal (near field enhanced geothermal system, binary)
  - Adjustments for advanced technology innovation scenario

Derivation of Resource Attributes

Once a basic list of resources was determined, the cost-and-performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the SSR tables , which is used to develop inputs for IRP modeling:

- Annual Technology Baseline (ATB) prepared by the National Renewable Energy Laboratory (NREL)[5]
- U.S. Energy Information Administration (EIA) "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies" ("EIA Report", both the 2024[6] and 2020[7] editions) prepared by Sargent and Lundy
- Original equipment manufacturers capital and operation and maintenance estimates
- Developer cost and performance estimates
- Publicly available cost and performance estimates
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options
- Additional references are provided in the Resource Option Descriptions section of this chapter

Most of the supply-side resource options rely on the ATB and EIA reports. Some resources contained in the SSR tables are not listed in the ATB, but were developed through other reports,

[4] Nuclear technology is intentionally limited to years outside the 2-4 year action plan window. Nuclear resource assumptions were discussed in the 2025 IRP public input meeting series and stakeholder feedback,
See Appendix M, stakeholder feedback form #1 (Peter Gross).
See Appendix M, stakeholder feedback form #41 (Nathan Strain).

[5] https://atb.nrel.gov/electricty/2024/index.

[6] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

[7] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf.

conversations with industry experts, developers and original equipment manufacturers (OEM's). The 2024 ATB with its numerous references and the 2024 EIA Report was used for:

- Natural Gas
  - SCCT (Aero)
  - CCCT (1x1 & 2x1)
    - Adjustments for 95% Carbon Capture
    - Adjustments for advanced technology innovation scenario
- Energy Storage
  - Lithium-Ion Batteries (20 MW, 200 MW, and 1,000 MW, 4-hour duration)
    - Adjustments for double duration
    - Adjustments for co-location
    - Adjustments for advanced technology innovation scenario
  - PHES (single and double reservoirs)
- Solar
  - Adjustments for advanced technology innovation scenario
- Wind
  - Adjustments for advanced technology innovation scenario
- Nuclear
  - Small Modular Reactor
  - Large Light Water Reactor
  - Adjustments for advanced technology innovation scenario
- Geothermal (near field enhanced geothermal system, binary)
  - Adjustments for advanced technology innovation scenario

The 2020 EIA Report provided the Internal Combustion Engines (ICE) data because no ICE option was included in the 2024 EIA report. The ICE option was included to address Oregon requirements for small-scale resources under 20 MW. Although the ICE option consists of 4 x 5.6 MW engines at ISO conditions, it is assumed that the engines, if not derated due to altitude or other factors, can be curtailed to meet the 20 MW threshold.

The brownfield cost adjustment was developed based on prior IRP estimates.

Hydrogen capable resource data is based on the following:[8]

- Adjustments for 100% hydrogen burning capability are based on conversations with OEMs and industry experts and the report "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems."[9] A 15% cost adder for new gas turbines indicated by Table 3 in the report was corroborated by OEMs and other industry experts.
- Adjustments for hydrogen storage are based on information in the U.S. Department of Energy (DOE) reports: "Pathways to Commercial Liftoff: Clean Hydrogen"[10] (Clean Hydrogen Liftoff

[8] The option of hydrogen as an alternative fuel, including electrolyzer cost and performance, was discussed in the course of the 2025 IRP public input meeting series. For specific recommendations and PacifiCorp's response, see Appendix M, stakeholder feedback form #23 (NP Energy, LLC)

[9] Simon Oberg, Mikael Odenberger, Filip Johnsson "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems," Division of Energy Technology, Chalmers University of Technology, 412 96, Gothenburg, Sweden, https://www.sciencedirect.com/science/article/pii/S0360319921039768

[10] https://liftoff.energy.gov/

report), "2022 Grid Energy Storage Technology Cost and Performance Assessment,"[11] and the Hydrogen and Fuel Cell Technologies Office's "Multi-Year Program Plan."[12]
- Electrolyzer costs are based on the DOE report "Hydrogen Production Cost from PEM Electrolysis – 2019,"[13] and the NREL report "Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolyzers."

Data for "Carbon Capture Retrofits at existing coal plants" is based on adjustments made to incorporate capital and operational costs of emission control technologies (SCR and FGD) needed to scrub flue gas prior to the carbon capture technology, and adjustments made to account for economies of scale.

Gravity Batteries costs were escalated from the 2023 IRP.

Adiabatic Compressed Air Energy Storage (ACAES) were originally escalated from the 2023 IRP which used data provided by Renewable Energy Storage Company (RESC), but later updated based on input from Hydrostor.

100-Hour Iron Air Battery data is based on information provided by Form Energy.

Pumped Thermal energy storage is based on integrated thermal storage for nuclear, but with a resistive heater for energy storage.

Data for "Adjustments for adding thermal energy storage to nuclear plants" represents thermal energy storage and only stores energy from the heat of the reactor, not from a resistive heater.

The following costs were excluded from the cost estimates provided by the referenced sources, but were added by the Company as appropriate, using confidential data specific to the Company's business practices:[14]
- Allowance for Funds Used During Construction (AFUDC)
- Capital Surcharge
- Escalation
- Property taxes

Interconnection costs and sales tax are included in the PLEXOS modeling depending on the locational node in which each technology is being considered.

Wind and Solar Generation Profiles

For the 2025 IRP, PacifiCorp has updated the wind and solar generation profiles for both existing resources and proxy resource options. PacifiCorp provided the location and expected generation levels for existing and contracted resources to a consultant, Hendrickson Renewables, and received

[11] https://www.energy.gov/sites/default/files/2022-09/2022%20Grid%20Energy%20Storage%20Technology%20Cost%20and%20Performance%20Assessment.pdf
[12] https://www.energy.gov/sites/default/files/2024-05/hfto-mypp-2024.pdf
[13] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master
[14] Additional cost considerations were the subject of discussion and feedback during the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #24 (NP Energy, LLC).

back an hourly generation profile for 2006-2023 that reflects expected performance under historical weather conditions.

For existing resources, results were tuned to recent historical actual generation levels, while resources that are not yet operating were tuned to forecasted output. For wind, hourly generation is based on hourly wind speeds and air density from the ERA5 reanalysis dataset, with scaling and adjustments to represent project-specific power curves and expected output.[15] For solar, hourly solar irradiance and weather data was extracted from a Vaisala satellite irradiance dataset[16] and configured in a PV_{syst} model[17] that was tuned to correspond to actual or forecasted output.

For proxy resources, PacifiCorp identified locations across its system, and Hendrickson Renewables determined the expected output of the equipment represented in NREL's ATB, which was used to develop cost inputs. In the 2023 IRP, PacifiCorp used one wind and solar profile for each of its five largest state jurisdictions (excluding California). For the 2025 IRP, wind and solar profiles have been developed which to correspond to thirteen different transmission areas spread across PacifiCorp's system. To account for technological differences that impact generation output, generation profiles were also developed for five small-scale wind profiles for the west side of the system, along with an off-shore wind profile for the potential lease area near Brookings.[18]

For many years, PacifiCorp has used a chaotic normal load forecast to account for the range of load conditions experienced. For each month of the year, the chaotic normal load forecast is derived from the most representative historical month from recent history (currently 2013-2022). The pattern of load in each of the selected months from history is reflected in every year of the forecast, with adjustments to account for the rotation of calendar days and weekdays from year to year, as well as for forecasted changes in load over time. As a result, every day of PacifiCorp's load forecast is tied to a specific day in history. For the 2025 IRP, the normalized wind and solar output modeled in Plexos is drawn from the same historical day as the load forecast. The result is a generation profile specific to each of the years of the IRP forecast (2025-2045) that inherently represents the correlation between renewable generation and load. The expanded historical generation data set developed for the 2025 IRP also enables stochastic analysis that captures the relationship between renewable generation and load in each of the historical years (2006-2023).

Resource Options and Attributes

Table 7.2 through Table 7.11 report characteristics, attributes and costs for resource options considered in the 2025 IRP. Unlike previous IRP's the SSR Table does not list multiple versions of the same technology for various altitudes. Instead, the location adjustments from Appendix A and B of the 2024 EIA[19] report are applied in PLEXOS. Total resource cost attributes for supply-

[15] European Centre for Medium-Range Weather Forecasts.https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5
[16] Vaisala. https://www.vaisala.com/
[17] PV_{syst}. https://www.pvsyst.com/
[18] Bureau of Ocean Energy Management. https://www.boem.gov/renewable-energy/state-activities/Oregon
[19] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

side resource options are based on estimates of the first-year, real-levelized costs for resources, stated in June 2024 dollars.[20,21] Table 7.1 provides a listing of these ten tables for convenience.

Table 7.1 – Supply-Side Resource Option Tables

	Characteristics and Costs	**Operating Characteristics and Environmental Data**
Thermal	Table 7.2	Table 7.4
Non-Thermal and Storage	Table 7.3	Table 7.5
	Additional Attributes and Fixed O&M	**Variable O&M, Total Cost and Credits**
Thermal	Table 7.6	Table 7.9
Non-Thermal	Table 7.7	Table 7.10
Storage	Table 7.8	Table 7.11

A Glossary of Terms and a Glossary of Acronyms from the SSR is summarized in Table 7.12 and Table 7.13.

[20] Supply-side resource attributes were discussed throughout the 2025 public input meeting series and generated stakeholder feedback forms inquiries. 2028 was determined to be the appropriate earliest commercial online year for most proxy resource options. However, PacifiCorp does not preclude the possibility of achieving specific (non-proxy) projects on an earlier timeline outside of the IRP.
See Appendix M, stakeholder feedback form #7 (Renewable Northwest).
See Appendix M, stakeholder feedback form #36 (Sierra Club).
[21] The supply-side resource table was made publicly available during the 2025 IRP public input meeting series and discussed extensively as it developed. IRP Support & Studies

Table 7.2 – 2025 Thermal Supply-Side Resources, Characteristics and Costs (2024$)

		Characteristics						Costs						
Fuel	Resource Description	Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Asset Life (yrs)	Base Capital ($/kW)	Var O&M ($/MWh)	Fraction Var O&M Capitalized	Fraction Var O&M Adjusted by Capacity Changes	Fixed O&M ($/kW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost ($/kW)
Biofuel	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	0	20	2025	2.5	2027	30	$2,131	$6.93	74%	91%	$42.82	3%	$14.59
Natural Gas	SCCT Aero, with SCR	0	50	2025	3.5	2028	40	$2,613	$7.40	87%	98%	$12.42	3%	$32.46
Natural Gas	SCCT Aero x4, with SCR	0	211	2025	3.5	2028	40	$1,789	$5.92	87%	98%	$9.93	3%	$32.46
Natural Gas	SCCT Frame "F" x1, with SCR	0	233	2025	5.0	2030	40	$1,387	$7.75	100%	99%	$27.92	3%	$12.13
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR	0	649	2025	5.0	2030	40	$1,839	$2.70	0%	100%	$42.44	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR	0	1,227	2025	5.0	2030	40	$1,553	$2.28	0%	100%	$35.18	0%	$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	0	565	2025	5.0	2030	+40	$3,429	$5.32	0%	100%	$77.07	0%	$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	0	1085	2025	5.0	2030	+40	$2,846	$4.83	0%	100%	$62.99	0%	$65.08
Natural Gas	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank + Δ for CT Brownfield construction	0	20	2025	2.5	2027	30	$1,918	$6.24	74%	91%	$42.82	3%	$14.59
Natural Gas	SCCT Aero, with SCR + Δ for CT Brownfield construction	0	50	2025	3.5	2028	40	$2,352	$6.66	87%	98%	$12.42	3%	$32.46
Natural Gas	SCCT Aero x4, with SCR + Δ for CT Brownfield construction	0	211	2025	3.5	2028	40	$1,610	$5.33	87%	98%	$9.93	3%	$32.46
Natural Gas	SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	0	233	2025	5.0	2030	40	$1,248	$6.98	100%	99%	$27.92	3%	$12.13
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	0	649	2025	5.0	2030	40	$1,655	$2.43	0%	100%	$42.44	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	0	1,227	2025	5.0	2030	40	$1,398	$2.05	0%	100%	$35.18	0%	$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	0	565	2025	5.0	2030	40	$3,086	$4.78	0%	100%	$77.07	0%	$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	0	1,085	2025	5.0	2030	40	$2,561	$4.34	0%	100%	$62.99	0%	$65.08
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for 100% Hydrogen burning capability	0	233	2025	5.0	2030	40	$1,595	$8.91	100%	99%	$27.92	3%	$13.95
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for 100% Hydrogen burning capability	0	649	2025	5.0	2030	40	$2,115	$3.11	0%	100%	$42.44	0%	$13.89
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for 100% Hydrogen burning capability	0	1,227	2025	5.0	2030	40	$1,786	$2.62	0%	100%	$35.18	0%	$13.67
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	233	2025	5.0	2030	40	$2,586	$8.18	100%	99%	$35.12	3%	$27.13
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	649	2025	5.0	2030	40	$3,038	$3.13	0%	100%	$49.64	0%	$27.08
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	1,227	2025	5.0	2030	40	$2,752	$2.70	0%	100%	$42.38	0%	$26.89
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	233	2025	5.0	2030	40	$2,098	$8.32	100%	99%	$40.78	3%	$27.13
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	649	2025	5.0	2030	40	$2,550	$3.27	0%	100%	$55.30	0%	$27.08
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	1,227	2025	5.0	2030	40	$2,264	$2.85	0%	100%	$48.04	0%	$26.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	0	649	2025	5.0	2030	+40	$1,832	$2.68	0%	100%	$41.33	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	0	1227	2025	5.0	2030	+40	$1,518	$2.23	0%	100%	$34.07	0%	$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS	0	565	2025	5.0	2030	+40	$3,261	$5.03	0%	100%	$72.60	0%	$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS	0	1085	2025	5.0	2030	+40	$2,637	$4.49	0%	100%	$57.74	0%	$65.08
Hydrogen	Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	0	-119	2025	5.0	2030	40	$561	$23.91	+0%	0.00	$10.28	100%	$32.46
Coal	CCS Dave Johnston 4 (costs on post retrofit basis)	5,541	-85	2027	5.0	2032	30	$3,501	$11.40	0%	0%	$277.68	0%	$53.20
Coal	CCS Hunter 1-3 (costs on post retrofit basis)	6,429	-297	2027	5.0	2032	30	$2,951	$9.73	0%	0%	$235.36	0%	$53.20
Coal	CCS Huntington 1&2 (costs on post retrofit basis)	6,933	-233	2027	5.0	2032	30	$2,951	$9.63	0%	0%	$242.12	0%	$53.20
Coal	CCS Jim Bridger 3&4 (costs on post retrofit basis)	7,513	-174	2025	5.0	2030	30	$2,598	$10.57	0%	0%	$254.91	0%	$53.20
Coal	CCS Wyodak (costs on post retrofit basis)	4,448	-69	2027	5.0	2032	30	$3,504	$11.69	0%	0%	$309.51	0%	$53.20
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case	N/A	600	2030	5.0	2035	60	$9,662	$9.74	0%	0%	$97.42	0%	$17.00
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case	N/A	600	2030	4.0	2034	60	$6,368	$8.74	0%	0%	$84.53	0%	$12.00
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	N/A	750	2030	5.0	2035	60	$10,628	$10.72	0%	0%	$107.16	0%	$17.00
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	N/A	750	2030	4.0	2034	60	$7,005	$9.61	0%	0%	$92.98	0%	$12.00
Nuclear	Large Light Water Reactor, Moderate Technology Case	N/A	2,000	2030	7.0	2037	60	$7,563	$9.38	0%	0%	$125.36	0%	$10.00
Nuclear	Large Light Water Reactor, Advanced Technology Case	N/A	2,000	2030	5.0	2035	60	$6,265	$7.88	0%	0%	$90.26	0%	$9.00
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary	N/A	707	2025	3.0	2028	30	$7,593	included in FOM	0%	0%	$194.00	6%	$125.09
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary + Δ Advanced Geothermal Technology Case	N/A	707	2025	3.0	2028	30	$5,949	included in FOM	0%	0%	$173.90	6%	$125.09

Table 7.3 – 2025 Non-Thermal Supply-Side Resources, Characteristics and Costs (2024$)

		Characteristics						Costs						
Fuel	Resource Description	Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Asset Life (yrs)	Base Capital ($/kW)	Var O&M ($/MWh)	Fraction Var O&M Capitalized	Var O&M Adjusted by Capacity Changes	Fixed O&M ($/kW-yr)	Fraction Fixed O&M Capitalized	Demolition Cost ($/kW)
Storage[1]	Li-Ion, 4-hour, 20 MW	N/A	20	2025	1.0	2026	20	$1,748	included in FOM	0%	0%	$45.05	0%	$29.94
Storage[1]	Li-Ion, 4-hour, 200 MW	N/A	200	2025	2.0	2027	20	$1,498	included in FOM	0%	0%	$38.77	0%	$25.66
Storage[1]	Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW	N/A	200	2025	2.0	2027	20	$2,557	included in FOM	0%	0%	$69.78	0%	$46.19
Storage[1]	Li-Ion, 4-hour, 1000 MW	N/A	1,000	2025	3.0	2028	20	$1,459	included in FOM	0%	0%	$36.92	0%	$25.66
Storage	Gravity Battery, 4-hour, 1000 MW	N/A	1,000	2025	3.0	2028	50	$2,021	included in FOM	0%	0%	$50.51	0%	$0.19
Storage	Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	N/A	1,000	2025	3.0	2028	50	$3,006	included in FOM	0%	0%	$90.92	0%	$0.35
Storage	Adiabatic CAES, 500 MW, 4000 MWh	N/A	500	2025	3.0	2028	50	$3,754	$2.60	50%	0%	$19.20	42%	$49.31
Storage	100-hour Iron Air	N/A	200	2030	2.0	2032	20	$2,730	included in FOM	0%	0%	$21.04	19%	$171.06
Storage	Pumped Hydro, Two New Reservoirs, 4-hour	N/A	400	2025	5.0	2030	100	$2,984	$0.58	0%	0%	$20.20	45%	$149.21
Storage	Pumped Hydro, Two New Reservoirs, 10-hour	N/A	400	2025	5.0	2030	100	$4,159	$0.58	0%	0%	$20.20	45%	$207.95
Storage	Pumped Hydro, One New Reservoir, 4-hour	N/A	400	2025	5.0	2030	100	$2,883	$0.58	0%	0%	$20.20	45%	$144.16
Storage	Pumped Hydro, One New Reservoir, 10-hour	N/A	400	2025	5.0	2030	100	$3,537	$0.58	0%	0%	$20.20	45%	$176.87
Storage	Pumped Thermal Energy Storage, 10-hour	N/A	100	2026	5.0	2031	60	$6,174	$0.70	~~0%~~	~~0%~~	$2.00	~~0%~~	$60.00
Storage	Pumped Thermal Energy Storage, 24-hour	N/A	50	2026	5.0	2031	60	$11,525	$0.70	~~0%~~	~~0%~~	$1.00	~~0%~~	$60.00
Solar	PV, 20 MW, Class 1-10	by location	20	2025	3.0	2028	25	$1,965	included in FOM	0%	0%	$18.16	12%	$39.29
Solar	PV, 200 MW, Class 1-10	by location	200	2025	3.0	2028	25	$1,217	included in FOM	0%	0%	$20.52	12%	$24.33
Solar	PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	by location	20	2025	3.0	2028	25	$1,832	included in FOM	0%	0%	$17.24	12%	$37.33
Solar	PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	by location	200	2025	3.0	2028	25	$1,135	included in FOM	0%	0%	$19.47	12%	$23.11
Wind	Wind Class 1-10, 20 MW	by location	20	2025	3.0	2028	30	$2,555	included in FOM	0%	0%	$38.79	35%	$63.57
Wind	Wind Class 1-6, 200 MW	by location	200	2025	5.0	2030	30	$1,421	included in FOM	0%	0%	$31.65	35%	$63.57
Wind	Wind Class 7, 200 MW	by location	200	2025	5.0	2030	30	$1,492	included in FOM	0%	0%	$31.65	35%	$63.57
Wind	Offshore, Wind Class 12	0	200	2027	5.0	2032	30	$8,341	included in FOM	0%	0%	$69.26	35%	$169.16
Wind	Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	by location	20	2025	3	2028	30	$2,434	included in FOM	0%	0%	$34.87	35%	$60.58
Wind	Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	by location	200	2025	5	2030	30	$1,354	included in FOM	0%	0%	$28.45	35%	$60.58
Wind	Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	by location	200	2025	5	2030	30	$1,422	included in FOM	0%	0%	$28.45	35%	$60.58
Wind	Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	0	200	2027	5	2032	30	$6,011	included in FOM	0%	0%	$63.21	35%	$121.92

[1] Assumed co-located

Table 7.4 – 2025 Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2024$)

		Operating Characteristics				Environmental Data				
Fuel	Resource Description	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)
Biofuel	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	8,295	41.13%	2.50%	5.0%	27.1	0.00152	0.02000	0.000	117
Natural Gas	SCCT Aero, with SCR	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00750	0.000	117
Natural Gas	SCCT Aero x4, with SCR	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00750	0.000	117
Natural Gas	SCCT Frame "F" x1, with SCR	9,717	35.12%	2.70%	3.9%	28.4	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank + Δ for CT Brownfield construction	8,295	41.13%	2.50%	5.0%	27.1	0.00152	0.02131	0.000	117
Natural Gas	SCCT Aero, with SCR + Δ for CT Brownfield construction	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00799	0.000	117
Natural Gas	SCCT Aero x4, with SCR + Δ for CT Brownfield construction	9,447	36.12%	2.90%	3.9%	27.0	0.00150	0.00799	0.000	117
Natural Gas	SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	9,717	35.12%	2.70%	3.9%	28.4	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00799	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00599	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00599	0.000	6
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for 100% Hydrogen burning capability	9,717	35.12%	2.70%	3.90%	28.4	0.00000	0.00750	0.000	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for 100% Hydrogen burning capability	6,040	56.49%	2.50%	3.80%	210.0	0.00000	0.00750	0.000	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for 100% Hydrogen burning capability	6,122	55.74%	2.50%	3.80%	210.0	0.00000	0.00750	0.000	0
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	9,717	35.12%	2.75%	3.90%	28.4	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	6,040	56.49%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	6,122	55.74%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	9,717	35.12%	2.75%	3.90%	28.4	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	6,040	56.49%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	6,122	55.74%	2.55%	3.80%	210.0	0.00196	0.00946	0.002	0
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	6,040	56.49%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	6,122	55.74%	2.50%	3.8%	210.0	0.00150	0.00750	0.000	117
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS	6,743	53.17%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS	6,843	52.46%	2.50%	3.8%	323.4	0.00150	0.00563	0.000	6
Hydrogen	Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	N/A	79.13%	1.50%	1.5%	45.7	0.00000	0.00000	0.000	0
Coal	CCS Dave Johnston 4 (costs on post retrofit basis)	14,795	23.06%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Hunter 1-3 (costs on post retrofit basis)	14,011	24.35%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Huntington 1&2 (costs on post retrofit basis)	13,662	24.98%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Jim Bridger 3&4 (costs on post retrofit basis)	14,483	23.56%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Coal	CCS Wyodak (costs on post retrofit basis)	16,653	20.49%	7.50%	7.50%	186.0	10.00000	0.07100	0.304	10
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case	9,180	37%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case	9,180	37%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	12,626	37.17%	2.00%	5.0%	720.0	0.00000	0.00000	0.000	0
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	12,626	37.17%	2.00%	5.0%	720.0	0.00000	0.00000	0.000	0
Nuclear	Large Light Water Reactor, Moderate Technology Case	10,497	33%	2%	5%	720.0	0.00000	0.00000	0.000	0
Nuclear	Large Light Water Reactor, Advanced Technology Case	10,497	33%	2%	5%	720.0	0.00000	0.00000	0.000	0
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary	N/A	N/A	10%	10%	510.0	n/a	n/a	n/a	n/a
Geothermal	Near Field Enhanhanced Geothermal System (NF-EGS) Binary + Δ Advanced Geothermal Technology Case	N/A	N/A	10.00%	10.00%	510.0	n/a	n/a	n/a	n/a

Table 7.5 – 2025 Non-Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2024$)

		Operating Characteristics				Environmental Data				
Fuel	Resource Description	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[1]	Li-Ion, 4-hour, 20 MW	n/a	85%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage[1]	Li-Ion, 4-hour, 200 MW	n/a	85%	1%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage[1]	Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW	n/a	85.00%	1.00%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage[1]	Li-Ion, 4-hour, 1000 MW	n/a	85%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Gravity Battery, 4-hour, 1000 MW	n/a	83%	1.0%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	n/a	83.00%	1.00%	included in CF	n/a	0.00000	0.00000	0.000	0
Storage	Adiabatic CAES, 500 MW, 4000 MWh	n/a	63%	1.1%	1.1%	n/a	0.00000	0.00000	0.000	0
Storage	100-hour Iron Air	n/a	43%	1.0%	included in CF	0.0	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, Two New Reservoirs, 4-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, Two New Reservoirs, 10-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, One New Reservoir, 4-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Hydro, One New Reservoir, 10-hour	n/a	80%	2.0%	4.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Thermal Energy Storage, 10-hour	n/a	55%	2.0%	3.0%	n/a	0.00000	0.00000	0.000	0
Storage	Pumped Thermal Energy Storage, 24-hour	n/a	55%	2.0%	3.0%	n/a	0.00000	0.00000	0.000	0
Solar	PV, 20 MW, Class 1-10	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 200 MW, Class 1-10	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Solar	PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-10, 20 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-6, 200 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 7, 200 MW	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Offshore, Wind Class 12	N/A	max CF: 47%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	N/A	by location	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a
Wind	Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	N/A	max CF: 47%	Included with CF	Included with CF	n/a	n/a	n/a	n/a	n/a

[1] Assumed co-located

Table 7.6 – 2025 IRP Thermal Supply-Side Resources, Additional Attributes and Fixed O&M

	Additional Attributes								Fixed O&M						
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor	Annual Payment ($/kW-Yr)	Capacity Factor	Storage Efficiency	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Gas Transport ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	Yes	0	$ 2,130.94	$ 14.59	6.890%	$147.83	41.13%	0%	$42.82	2.62%	$1.12	$0.00	$43.94	$191.77	$53.22
SCCT Aero, with SCR	No	0	$ 2,612.80	$ 32.46	6.101%	$161.39	36.12%	0%	$12.42	2.62%	$0.32	$0.00	$12.74	$174.13	$55.03
SCCT Aero x4, with SCR	No	0	$ 1,789.35	$ 32.46	6.104%	$111.20	36.12%	0%	$9.93	2.62%	$0.26	$0.00	$10.19	$121.40	$38.37
SCCT Frame "F" x1, with SCR	No	0	$ 1,386.92	$ 12.13	6.100%	$85.34	35.12%	0%	$27.92	2.62%	$0.73	$0.00	$28.65	$114.00	$37.06
CCCT Dry "H", 1X1, DF, with SCR	No	0	$ 1,839.00	$ 12.08	6.233%	$115.38	56.49%	0%	$42.44	2.62%	$1.11	$0.00	$43.55	$158.93	$32.12
Goshen	Yes	2,814	$ 1,857.39	$ 12.08	6.233%	$116.52	56.49%	0%	$42.44	2.62%	$1.11	$60.34	$103.89	$220.41	$44.54
Wasatch Front	Yes	4,225	$ 1,820.61	$ 12.08	6.233%	$114.23	56.49%	0%	$42.44	2.62%	$1.11	$9.25	$52.81	$167.04	$33.75
Wyoming East	Yes	6,130	$ 1,820.61	$ 12.08	6.233%	$114.23	56.49%	0%	$42.44	2.62%	$1.11	$16.33	$59.88	$174.11	$35.18
CCCT Dry "H", 2X1, DF, with SCR	No	0	$ 1,553.26	$ 11.89	6.234%	$97.57	55.74%	0%	$35.18	2.62%	$0.92	$0.00	$36.10	$133.67	$27.38
Goshen	Yes	2,814	$ 1,568.79	$ 11.89	6.234%	$98.54	55.74%	0%	$35.18	2.62%	$0.92	$61.16	$97.26	$195.80	$40.10
Wasatch Front	Yes	4,225	$ 1,537.73	$ 11.89	6.234%	$96.60	55.74%	0%	$35.18	2.62%	$0.92	$9.38	$45.48	$142.08	$29.10
Wyoming East	Yes	6,130	$ 1,537.73	$ 11.89	6.234%	$96.60	55.74%	0%	$35.18	2.62%	$0.92	$16.55	$52.65	$149.26	$30.57
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	No	0	$ 3,429.38	$ 65.28	6.239%	$218.03	53.17%	0%	$77.07	5.54%	$4.27	$0.00	$81.34	$299.37	$64.28
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	No	0	$ 2,846.02	$ 65.08	6.241%	$181.68	52.46%	0%	$62.99	5.54%	$3.49	$0.00	$66.48	$248.16	$54.00
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	No	0	$ 1,917.85	$ 14.59	6.891%	$133.16	41.13%	0%	$42.82	2.62%	$1.12	$0.00	$43.94	$177.10	$49.15
SCCT Aero, with SCR + Δ for CT Brownfield construction	No	0	$ 2,351.52	$ 32.46	6.102%	$145.47	36.12%	0%	$12.42	2.62%	$0.32	$0.00	$12.74	$158.21	$50.00
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	No	0	$ 1,610.42	$ 32.46	6.105%	$100.30	36.12%	0%	$9.93	2.62%	$0.26	$0.00	$10.19	$110.49	$34.92
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	No	0	$ 1,248.23	$ 12.13	6.100%	$76.88	35.12%	0%	$27.92	2.62%	$0.73	$0.00	$28.65	$105.53	$34.31
Goshen-Brownfield	Yes	2,814	$ 1,260.71	$ 12.13	6.100%	$77.64	35.12%	0%	$27.92	2.62%	$0.73	$96.20	$124.85	$202.50	$65.83
Wasatch Front-Brownfield	Yes	4,225	$ 1,235.75	$ 12.13	6.100%	$76.12	35.12%	0%	$27.92	2.62%	$0.73	$14.72	$43.38	$119.50	$38.85
Wyoming East-Brownfield	Yes	6,130	$ 1,235.75	$ 12.13	6.100%	$76.12	35.12%	0%	$27.92	2.62%	$0.73	$25.80	$54.45	$130.57	$42.45
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	No	0	$ 1,655.10	$ 12.08	6.234%	$103.93	56.49%	0%	$42.44	2.62%	$1.11	$0.00	$43.55	$147.48	$29.80
Goshen-Brownfield	Yes	2,814	$ 1,671.65	$ 12.08	6.234%	$104.96	56.49%	0%	$42.44	2.62%	$1.11	$60.34	$103.89	$208.85	$42.20
Wasatch Front-Brownfield	Yes	4,225	$ 1,638.55	$ 12.08	6.234%	$102.90	56.49%	0%	$42.44	2.62%	$1.11	$9.25	$52.81	$155.71	$31.46
Wyoming East-Brownfield	Yes	6,130	$ 1,638.55	$ 12.08	6.234%	$102.90	56.49%	0%	$42.44	2.62%	$1.11	$16.33	$59.88	$162.78	$32.89
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	No	0	$ 1,397.93	$ 11.89	6.234%	$87.89	55.74%	0%	$35.18	2.62%	$0.92	$0.00	$36.10	$123.99	$25.40
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	No	0	$ 3,086.44	$ 65.28	6.240%	$196.67	53.17%	0%	$77.07	5.54%	$4.27	$0.00	$81.34	$278.00	$59.69
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	No	0	$ 2,561.42	$ 65.08	6.242%	$163.95	52.46%	0%	$62.99	5.54%	$3.49	$0.00	$66.48	$230.43	$50.14
SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 1,594.96	$ 13.95	5.605%	$90.18	35.12%	0%	$27.92	2.62%	$0.73	$0.00	$28.65	$118.83	$38.63
CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 2,114.85	$ 13.89	5.604%	$119.29	56.49%	0%	$42.44	2.62%	$1.11	$0.00	$43.55	$162.85	$32.91
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 1,786.25	$ 13.67	5.604%	$100.87	55.74%	0%	$35.18	2.62%	$0.92	$0.00	$36.10	$136.97	$28.05
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 2,585.93	$ 27.13	9.271%	$242.26	35.12%	0%	$35.12	2.62%	$0.92	$0.00	$36.04	$278.30	$90.47
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 3,038.01	$ 27.08	9.254%	$283.64	56.49%	0%	$49.64	2.62%	$1.30	$0.00	$50.94	$334.59	$67.61
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 2,752.27	$ 26.89	9.263%	$257.43	55.74%	0%	$42.38	2.62%	$1.11	$0.00	$43.49	$300.93	$61.63
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,097.84	$ 27.13	9.255%	$196.67	35.12%	0%	$40.78	2.62%	$1.07	$0.00	$41.85	$238.51	$77.54
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,549.91	$ 27.08	9.245%	$238.24	56.49%	0%	$55.30	2.62%	$1.45	$0.00	$56.75	$294.99	$59.61
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,264.18	$ 26.89	9.250%	$211.92	55.74%	0%	$48.04	2.62%	$1.26	$0.00	$49.30	$261.22	$53.50
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	No	0	$ 1,831.63	$ 12.08	6.233%	$114.92	56.49%	0%	$41.33	2.62%	$1.08	$0.00	$42.41	$157.33	$31.79
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	No	0	$ 1,517.84	$ 11.89	6.234%	$95.36	55.74%	0%	$34.07	2.62%	$0.89	$0.00	$34.96	$130.32	$26.69
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS	No	0	$ 3,260.88	$ 65.28	6.233%	$207.32	53.17%	0%	$72.60	5.54%	$4.02	$0.00	$76.62	$283.94	$60.97
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS	No	0	$ 2,637.12	$ 65.08	6.234%	$168.46	52.46%	0%	$57.74	5.54%	$3.20	$0.00	$60.94	$229.40	$49.92
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	Yes	0	$ 560.99	$ 32.46	5.628%	$33.40	79.13%	0%	$10.28	0.00%	$0.00	$0.00	$10.28	$43.68	$6.30
CCS Dave Johnston 4 (costs on post retrofit basis)	No	5,541	$ 3,500.78	$ 53.20	6.447%	$229.12	23.06%	0%	$277.68	5.54%	$15.38	$0.00	$293.06	$522.19	$258.46
CCS Hunter 1-3 (costs on post retrofit basis)	No	6,429	$ 2,951.20	$ 53.20	6.451%	$193.81	24.35%	0%	$235.36	5.54%	$13.04	$0.00	$248.39	$442.21	$207.29
CCS Huntington 1&2 (costs on post retrofit basis)	No	6,933	$ 2,951.40	$ 53.20	6.451%	$193.83	24.98%	0%	$242.12	5.54%	$13.41	$0.00	$255.53	$449.36	$205.39
CCS Jim Bridger 3&4 (costs on post retrofit basis)	No	7,513	$ 2,598.38	$ 53.20	6.454%	$171.13	23.56%	0%	$254.91	5.54%	$14.12	$0.00	$269.03	$440.16	$213.28
CCS Wyodak (costs on post retrofit basis)	No	4,448	$ 3,504.25	$ 53.20	6.447%	$229.35	20.49%	0%	$309.51	5.54%	$17.15	$0.00	$326.65	$556.00	$309.76
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	Yes	N/A	$ 9,662.09	$ 17.00	3.919%	$379.32	37.17%	0%	$97.42	9.42%	$9.18	$0.00	$106.60	$485.92	$149.24
Goshen	Yes	2,814	$ 9,855.33	$ 17.00	3.919%	$386.90	37.17%	0%	$97.42	9.42%	$9.18	$0.00	$106.60	$493.50	$151.56
Wasatch Front	Yes	4,225	$ 9,855.33	$ 17.00	3.545%	$349.97	37.17%	0%	$97.42	9.42%	$9.18	$0.00	$106.60	$456.57	$140.22
Wyoming East	Yes	6,130	$ 9,565.47	$ 17.00	3.545%	$339.70	37.17%	0%	$97.42	9.42%	$9.18	$0.00	$106.60	$446.30	$137.07
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	No	N/A	$ 6,368.23	$ 12.00	3.919%	$250.04	37.17%	0%	$84.53	9.42%	$7.97	$0.00	$92.49	$342.53	$105.20
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	No	N/A	$ 10,628.30	$ 17.00	3.919%	$417.19	37.17%	0%	$107.16	9.42%	$10.10	$0.00	$117.26	$534.45	$164.14
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	No	N/A	$ 7,005.05	$ 12.00	3.919%	$275.00	37.17%	0%	$92.98	9.42%	$8.76	$0.00	$101.74	$376.74	$115.70
Large Light Water Reactor, Moderate Technology Case	No	N/A	$ 7,562.87	$ 10.00	3.919%	$296.78	32.51%	0%	$125.36	9.42%	$11.81	$0.00	$137.17	$433.95	$152.40
Large Light Water Reactor, Advanced Technology Case	No	N/A	$ 6,265.25	$ 9.00	3.919%	$245.89	32.51%	0%	$90.26	0.87%	$0.79	$0.00	$91.04	$336.93	$118.32
Near Field Enhanhanced Geothermal System (NF-EGS) Binary	Yes	N/A	$ 7,593.06	$ 125.09	5.178%	$399.65	90.00%	0%	$194.00	0.00%	$0.00	$0.00	$194.00	$593.65	$75.30
Southern OR	Yes	497	$ 8,883.88	$ 125.09	5.178%	$466.48	90.00%	0%	$194.00	0.00%	$0.00	$0.00	$194.00	$660.48	$83.78
Wasatch Front	Yes	4,225	$ 7,593.06	$ 125.09	4.817%	$371.78	90.00%	0%	$194.00	0.87%	$1.69	$0.00	$195.69	$567.47	$71.98

Table 7.7 – 2025 IRP Non-Thermal Supply-Side Resources, Additional Attributes and Fixed O&M

	Additional Attributes								Fixed O&M						
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor	Annual Payment ($/kW-Yr)	Capacity Factor	Storage Efficiency	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Gas Transport ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
PV, 20 MW, Class 1-10	Yes	by location	$ 1,964.64	$ 39.29	6.861%	$137.49	by location	0%	$18.16	1.37%	$0.25	$0.00	$18.41	$155.90	$0.00
Portland North Coast	Yes	19	$ 2,082.51	$ 39.29	6.861%	$145.58	24.49%	0%	$18.16	1.37%	$0.25	$0.00	$18.41	$163.99	$76.45
Southern OR	Yes	497	$ 2,180.75	$ 39.29	6.861%	$152.32	29.29%	0%	$18.16	1.37%	$0.25	$0.00	$18.41	$170.73	$66.54
Walla Walla	Yes	2,353	$ 2,003.93	$ 39.29	6.861%	$140.19	25.96%	0%	$18.16	1.37%	$0.25	$0.00	$18.41	$158.60	$69.74
Goshen	Yes	2,814	$ 1,984.28	$ 39.29	6.861%	$138.84	27.79%	0%	$18.16	1.37%	$0.25	$0.00	$18.41	$157.25	$64.59
Wasatch Front	Yes	4,225	$ 1,964.64	$ 39.29	6.861%	$137.49	29.00%	0%	$18.16	1.37%	$0.25	$0.00	$18.41	$155.90	$61.38
Wyoming East	Yes	6,130	$ 1,964.64	$ 39.29	6.861%	$137.49	27.47%	0%	$18.16	1.37%	$0.25	$0.00	$18.41	$155.90	$64.79
PV, 200 MW, Class 1-10	Yes	by location	$ 1,216.55	$ 24.33	6.861%	$85.14	by location	0%	$20.52	1.37%	$0.28	$0.00	$20.80	$105.93	$0.00
Portland North Coast	Yes	19	$ 1,289.55	$ 24.33	6.861%	$90.15	24.49%	0%	$20.52	1.37%	$0.28	$0.00	$20.80	$110.94	$51.72
Southern OR	Yes	497	$ 1,350.37	$ 24.33	6.861%	$94.32	29.29%	0%	$20.52	1.37%	$0.28	$0.00	$20.80	$115.12	$44.87
Walla Walla	Yes	2,353	$ 1,240.88	$ 24.33	6.861%	$86.81	25.96%	0%	$20.52	1.37%	$0.28	$0.00	$20.80	$107.60	$47.32
Goshen	Yes	2,814	$ 1,228.72	$ 24.33	6.861%	$85.97	27.79%	0%	$20.52	1.37%	$0.28	$0.00	$20.80	$106.77	$43.86
Wasatch Front	Yes	4,225	$ 1,216.55	$ 24.33	6.861%	$85.14	29.00%	0%	$20.52	1.37%	$0.28	$0.00	$20.80	$105.93	$41.71
Wyoming East	Yes	6,130	$ 1,216.55	$ 24.33	6.861%	$85.14	27.47%	0%	$20.52	1.37%	$0.28	$0.00	$20.80	$105.93	$44.02
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	by location	$ 1,832.22	$ 37.33	6.862%	$128.29	by location	0%	$17.24	1.37%	$0.24	$0.00	$17.48	$145.76	$0.00
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	by location	$ 1,134.56	$ 23.11	6.862%	$79.44	by location	0%	$19.47	1.37%	$0.27	$0.00	$19.74	$99.18	$0.00
Wind Class 1-10, 20 MW	Yes	by location	$ 2,554.58	$ 63.57	6.292%	$164.73	by location	0%	$38.79	4.39%	$1.70	$0.00	$40.49	$205.22	$0.00
Portland North Coast	Yes	19	$ 2,835.59	$ 63.57	6.292%	$182.42	24.91%	0%	$38.79	4.39%	$1.70	$0.00	$40.49	$222.90	$102.14
Southern OR	Yes	497	$ 3,014.41	$ 63.57	6.292%	$193.67	25.18%	0%	$38.79	4.39%	$1.70	$0.00	$40.49	$234.15	$106.14
Walla Walla	Yes	2,353	$ 2,656.77	$ 63.57	6.292%	$171.16	23.13%	0%	$38.79	4.39%	$1.70	$0.00	$40.49	$211.65	$104.46
Goshen	Yes	2,814	$ 2,605.68	$ 63.57	6.292%	$167.95	#N/A	0%	$38.79	4.39%	$1.70	$0.00	$40.49	$208.44	$0.00
Wasatch Front	Yes	4,225	$ 2,580.13	$ 63.57	6.292%	$166.34	#N/A	0%	$38.79	4.39%	$1.70	$0.00	$40.49	$206.83	$0.00
Wyoming East	Yes	6,130	$ 2,503.49	$ 63.57	6.292%	$161.52	#N/A	0%	$38.79	4.39%	$1.70	$0.00	$40.49	$202.01	$0.00
Wind Class 1-6, 200 MW	Yes	by location	$ 1,421.10	$ 63.57	6.316%	$93.77	by location	0%	$31.65	4.39%	$1.39	$0.00	$33.04	$126.81	$0.00
Portland North Coast	Yes	19	$ 1,577.43	$ 63.57	6.316%	$103.65	37.62%	0%	$31.65	4.39%	$1.39	$0.00	$33.04	$136.68	$41.47
Southern OR	Yes	497	$ 1,676.90	$ 63.57	6.316%	$109.93	34.06%	0%	$31.65	4.39%	$1.39	$0.00	$33.04	$142.97	$47.92
Walla Walla	Yes	2,353	$ 1,477.95	$ 63.57	6.316%	$97.36	32.59%	0%	$31.65	4.39%	$1.39	$0.00	$33.04	$130.40	$45.68
Goshen	Yes	2,814	$ 1,449.53	$ 63.57	6.316%	$95.57	30.28%	0%	$31.65	4.39%	$1.39	$0.00	$33.04	$128.61	$48.49
Wasatch Front	Yes	4,225	$ 1,435.32	$ 63.57	6.316%	$94.67	30.42%	0%	$31.65	4.39%	$1.39	$0.00	$33.04	$127.71	$47.93
Wyoming East	Yes	6,130	$ 1,392.68	$ 63.57	6.316%	$91.98	41.25%	0%	$31.65	4.39%	$1.39	$0.00	$33.04	$125.02	$34.60
Wind Class 7, 200 MW	No	by location	$ 1,491.78	$ 63.57	6.313%	$98.19	by location	0%	$31.65	4.39%	$1.39	$0.00	$33.04	$131.23	$0.00
Offshore, Wind Class 12	Yes	0	$ 8,340.57	$ 169.16	6.286%	$534.92	#N/A	0%	$69.26	4.39%	$3.04	$0.00	$72.30	$607.22	$0.00
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 2,434.26	$ 60.58	6.292%	$156.98	by location	0%	$34.87	4.39%	$1.53	$0.00	$36.40	$193.37	$0.00
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 1,354.17	$ 60.58	6.316%	$89.36	by location	0%	$28.45	4.39%	$1.25	$0.00	$29.70	$119.06	$0.00
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 1,421.51	$ 60.58	6.313%	$93.56	by location	0%	$28.45	4.39%	$1.25	$0.00	$29.70	$123.27	$0.00
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	No	0	$ 6,011.05	$ 121.92	6.286%	$385.52	#N/A	0%	$63.21	4.39%	$2.78	$0.00	$65.99	$451.51	$0.00

Table 7.8 – 2025 IRP Storage Supply-Side Resources, Additional Attributes and Fixed O&M

	Additional Attributes								Fixed O&M						
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost	Demolition Cost	Payment Factor	Annual Payment ($/kW-Yr)	Capacity Factor	Storage Efficiency	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Gas Transport ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
Li-Ion, 4-hour, 20 MW[1]	No	N/A	$ 1,747.61	$ 29.94	5.354%	$95.17	16.67%	85%	$45.05	0.00%	$0.00	$0.00	$45.05	$140.22	$96.04
Li-Ion, 4-hour, 200 MW[1]	No	N/A	$ 1,497.89	$ 25.66	5.354%	$81.57	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$120.34	$82.42
Portland North Coast	Yes	19	$ 1,587.77	$ 25.66	5.354%	$86.38	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$125.15	$85.72
Southern OR	Yes	497	$ 1,617.73	$ 25.66	5.354%	$87.99	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$126.75	$86.82
Walla Walla	Yes	2,353	$ 1,542.83	$ 25.66	5.354%	$83.98	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$122.74	$84.07
Goshen	Yes	2,814	$ 1,527.85	$ 25.66	5.354%	$83.18	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$121.94	$83.52
Wasatch Front	Yes	4,225	$ 1,542.83	$ 25.66	4.452%	$69.83	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$108.60	$74.38
Wyoming East	Yes	6,130	$ 1,482.92	$ 25.66	4.452%	$67.16	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$105.93	$72.55
Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW[1]	No	N/A	$ 2,556.57	$ 46.19	5.355%	$139.38	33.33%	85%	$69.78	0.00%	$0.00	$0.00	$69.78	$209.16	$71.63
Portland North Coast	Yes	19	$ 2,709.97	$ 46.19	5.355%	$147.59	33.33%	85%	$69.78	0.00%	$0.00	$0.00	$69.78	$217.37	$74.44
Southern OR	Yes	497	$ 2,761.10	$ 46.19	5.355%	$150.33	33.33%	85%	$69.78	0.00%	$0.00	$0.00	$69.78	$220.11	$75.38
Walla Walla	Yes	2,353	$ 2,633.27	$ 46.19	5.355%	$143.48	33.33%	85%	$69.78	0.00%	$0.00	$0.00	$69.78	$213.27	$73.04
Goshen	Yes	2,814	$ 2,607.71	$ 46.19	5.355%	$142.12	33.33%	85%	$69.78	0.00%	$0.00	$0.00	$69.78	$211.90	$72.57
Wasatch Front	Yes	4,225	$ 2,633.27	$ 46.19	4.453%	$119.32	33.33%	85%	$69.78	0.00%	$0.00	$0.00	$69.78	$189.10	$64.76
Wyoming East	Yes	6,130	$ 2,531.01	$ 46.19	4.453%	$114.76	33.33%	85%	$69.78	0.00%	$0.00	$0.00	$69.78	$184.54	$63.20
Li-Ion, 4-hour, 1000 MW[1]	No	N/A	$ 1,459.50	$ 25.66	5.356%	$79.55	16.67%	85%	$36.92	0.00%	$0.00	$0.00	$36.92	$116.47	$79.77
Li-Ion, 4-hour, 200 MW	No	N/A	$ 1,497.89	$ 25.66	5.354%	$81.57	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$120.34	$82.42
Portland North Coast	Yes	19	$ 1,587.77	$ 25.66	5.354%	$86.38	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$125.15	$85.72
Southern OR	Yes	497	$ 1,617.73	$ 25.66	5.354%	$87.99	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$126.75	$86.82
Walla Walla	Yes	2,353	$ 1,542.83	$ 25.66	5.354%	$83.98	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$122.74	$84.07
Goshen	Yes	2,814	$ 1,527.85	$ 25.66	5.354%	$83.18	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$121.94	$83.52
Wasatch Front	Yes	4,225	$ 1,542.83	$ 25.66	4.452%	$69.83	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$108.60	$74.38
Wyoming East	Yes	6,130	$ 1,482.92	$ 25.66	4.452%	$67.16	16.67%	85%	$38.77	0.00%	$0.00	$0.00	$38.77	$105.93	$72.55
Gravity Battery, 4-hour, 1000 MW	Yes	N/A	$ 2,020.99	$ 0.19	2.916%	$58.94	16.67%	83%	$50.51	0.00%	$0.00	$0.00	$50.51	$109.45	$74.97
Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	No	N/A	$ 3,006.34	$ 0.35	2.916%	$87.68	33.33%	83%	$90.92	5.48%	$4.98	$0.00	$95.90	$183.58	$62.87
Adiabatic CAES, 500 MW, 4000 MWh	No	N/A	$ 3,754.00	$ 49.31	4.288%	$163.09	33.33%	63%	$19.20	0.00%	$0.00	$0.00	$19.20	$182.29	$62.43
100-hour Iron Air	Yes	N/A	$ 2,729.67	$ 171.06	4.581%	$132.88	30.07%	43%	$21.04	2.62%	$0.55	$0.00	$21.59	$154.47	$58.64
Pumped Hydro, Two New Reservoirs, 4-hour	No	N/A	$ 2,984.23	$ 149.21	3.121%	$97.79	16.67%	80%	$20.20	2.62%	$0.53	$0.00	$20.73	$118.52	$81.18
Pumped Hydro, Two New Reservoirs, 10-hour	Yes	N/A	$ 4,158.90	$ 207.95	3.121%	$136.29	41.67%	80%	$20.20	2.62%	$0.53	$0.00	$20.73	$157.02	$43.02
Portland North Coast	Yes	19	$ 4,408.44	$ 207.95	3.121%	$144.08	41.67%	80%	$20.20	2.62%	$0.53	$0.00	$20.73	$164.81	$45.15
Southern OR	Yes	497	$ 4,491.61	$ 207.95	3.121%	$146.67	41.67%	80%	$20.20	2.62%	$0.53	$0.00	$20.73	$167.40	$45.86
Goshen	Yes	2,814	$ 4,242.08	$ 207.95	3.121%	$138.89	41.67%	80%	$20.20	2.62%	$0.53	$0.00	$20.73	$159.61	$43.73
Wasatch Front	Yes	4,225	$ 4,283.67	$ 207.95	2.582%	$115.97	41.67%	80%	$20.20	2.62%	$0.53	$0.00	$20.73	$136.70	$37.45
Wyoming East	Yes	6,130	$ 4,117.31	$ 207.95	2.582%	$111.68	41.67%	80%	$20.20	2.62%	$0.53	$0.00	$20.73	$132.41	$36.28
Pumped Hydro, One New Reservoir, 4-hour	No	N/A	$ 2,883.24	$ 144.16	3.121%	$94.49	16.67%	80%	$20.20	2.62%	$0.53	$0.00	$20.73	$115.21	$78.91
Pumped Hydro, One New Reservoir, 10-hour	No	N/A	$ 3,537.41	$ 176.87	3.121%	$115.92	41.67%	80%	$20.20	2.62%	$0.53	$0.00	$20.73	$136.65	$37.44
Pumped Thermal Energy Storage, 10-hour	No	N/A	$ 6,173.76	$ 60.00	3.361%	$209.52	35.48%	55%	$2.00	2.62%	$0.05	$0.00	$2.05	$211.57	$68.06
Pumped Thermal Energy Storage, 24-hour	No	N/A	$ 11,525.17	$ 60.00	3.362%	$389.49	35.48%	55%	$1.00	1.37%	$0.01	$0.00	$1.01	$390.51	$125.63

Table 7.9 – 2025 IRP Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits

	Variable O&M					Credits		
Resource Description	Levelized Fuel ($/MWh)	O&M ($/MWh)	Capitalized Premium	O&M Capitalized ($/MWh)	Total Resource Cost ($/MWh)	Tax Credits ($/MWh)	Total Resource Cost with PTC / ITC Credits ($/MWh)	Adjusted Total Resource Cost with PTC / ITC Credits
Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	$ 357.85	$6.93	14.39%	$1.00	$418.99		$418.99	$387.57
SCCT Aero, with SCR	$ 53.04	$7.40	14.39%	$1.07	$116.54		$116.54	-
SCCT Aero x4, with SCR	$ 53.04	$5.92	14.39%	$0.85	$98.18		$98.18	-
SCCT Frame "F" x1, with SCR	$ 54.56	$7.75	14.39%	$1.12	$100.48		$100.48	-
CCCT Dry "H", 1X1, DF, with SCR	$ 33.91	$2.70	14.39%	$0.39	$69.12		$69.12	-
Goshen	$ 34.65	$2.70	14.39%	$0.39	$82.28		$82.28	$77.10
Wasatch Front	$ 34.74	$2.70	14.39%	$0.39	$71.58		$71.58	$67.07
Wyoming East	$ 30.05	$2.70	14.39%	$0.39	$68.32		$68.32	$64.02
CCCT Dry "H", 2X1, DF, with SCR	$ 34.37	$2.28	14.39%	$0.33	$64.36		$64.36	-
Goshen	$ 35.12	$2.28	14.39%	$0.33	$77.83		$77.83	-
Wasatch Front	$ 35.21	$2.28	14.39%	$0.33	$66.91		$66.91	-
Wyoming East	$ 30.45	$2.28	14.39%	$0.33	$63.63		$63.63	-
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	$ 37.86	$5.32	11.52%	$0.61	$108.07		$108.07	-
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	$ 38.42	$4.83	11.52%	$0.56	$97.80		$97.80	-
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	$ 46.57	$6.24	14.39%	$0.90	$102.86		$102.86	-
SCCT Aero, with SCR + Δ for CT Brownfield construction	$ 53.04	$6.66	14.39%	$0.96	$110.67		$110.67	-
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	$ 53.04	$5.33	14.39%	$0.77	$94.06		$94.06	-
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	$ 54.56	$6.98	14.39%	$1.00	$96.85		$96.85	-
Goshen-Brownfield	$ 54.23	$6.98	14.39%	$1.00	$128.04		$128.04	$119.59
Wasatch Front-Brownfield	$ 54.29	$6.98	14.39%	$1.00	$101.11		$101.11	$94.44
Wyoming East-Brownfield	$ 53.90	$6.98	14.39%	$1.00	$104.33		$104.33	$97.45
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	$ 33.91	$2.43	14.39%	$0.35	$66.50		$66.50	-
Goshen-Brownfield	$ 34.01	$2.43	14.39%	$0.35	$79.00		$79.00	$74.02
Wasatch Front-Brownfield	$ 34.12	$2.43	14.39%	$0.35	$68.36		$68.36	$64.06
Wyoming East-Brownfield	$ 34.12	$2.43	14.39%	$0.35	$69.79		$69.79	$65.40
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	$ 34.37	$2.05	14.39%	$0.30	$62.11		$62.11	-
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	$ 37.86	$4.78	11.52%	$0.55	$102.89		$102.89	-
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	$ 38.42	$4.34	11.52%	$0.50	$93.40		$93.40	-
SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	$ 54.56	$8.91	14.39%	$1.28	$103.39		$103.39	-
CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	$ 33.91	$3.11	14.39%	$0.45	$70.38		$70.38	-
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	$ 34.37	$2.62	14.39%	$0.38	$65.42		$65.42	-
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 54.56	$8.18	14.39%	$1.18	$154.38		$154.38	-
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 33.91	$3.13	14.39%	$0.45	$105.10		$105.10	-
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 34.37	$2.70	14.39%	$0.39	$99.10		$99.10	-
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 54.56	$8.32	14.39%	$1.20	$141.62		$141.62	-
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 33.91	$3.27	14.39%	$0.47	$97.27		$97.27	-
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 34.37	$2.85	14.39%	$0.41	$91.14		$91.14	-
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	$ 33.91	$2.68	14.39%	$0.39	$68.77		$68.77	-
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	$ 34.37	$2.23	14.39%	$0.32	$63.62		$63.62	-
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS	$ 37.86	$5.03	11.52%	$0.58	$104.43		$104.43	-
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS	$ 38.42	$4.49	11.52%	$0.52	$93.34		$93.34	-
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	$ -	$23.91	0.00%	$0.00	$30.21		$30.21	-
CCS Dave Johnston 4 (costs on post retrofit basis)	$ -	$11.40	11.52%	$1.31	$271.17	$ (43.09)	$228.08	-
CCS Hunter 1-3 (costs on post retrofit basis)	$ -	$9.73	11.52%	$1.12	$218.14	$ (40.81)	$177.33	-
CCS Huntington 1&2 (costs on post retrofit basis)	$ -	$9.63	11.52%	$1.11	$216.13	$ (39.79)	$176.34	-
CCS Jim Bridger 3&4 (costs on post retrofit basis)	$ -	$10.57	11.52%	$1.22	$225.06	$ (42.18)	$182.88	-
CCS Wyodak (costs on post retrofit basis)	$ -	$11.69	11.52%	$1.35	$322.79	$ (48.50)	$274.29	-
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	$ -	$9.74	0.00%	$0.00	$158.98	$ (33.32)	$125.66	-
Goshen	$ -	$9.74	0.00%	$0.00	$161.31	$ (33.99)	$127.31	$120.95
Wasatch Front	$ -	$9.74	0.00%	$0.00	$149.97	$ (45.31)	$104.66	$99.42
Wyoming East	$ -	$9.74	0.00%	$0.00	$146.81	$ (43.98)	$102.83	$97.69
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	$ -	$8.74	0.00%	$0.00	$113.94	$ (21.96)	$91.97	-
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	$ -	$10.72	0.00%	$0.00	$174.86	$ (36.66)	$138.20	-
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	$ -	$9.61	0.00%	$0.00	$125.32	$ (24.16)	$101.16	-
Large Light Water Reactor, Moderate Technology Case	$ -	$9.38	0.00%	$0.00	$161.78	$ (29.83)	$131.95	-
Large Light Water Reactor, Advanced Technology Case	$ -	$7.88	0.00%	$0.00	$126.20	$ (24.71)	$101.50	-
Near Field Enhanhanced Geothermal System (NF-EGS) Binary	$ -	$0.00	0.00%	$0.00	$75.30	$ (10.44)	$64.86	-
Southern OR	$ -	$0.00	0.00%	$0.00	$83.78	$ (12.21)	$71.56	-
Wasatch Front	$ -	$0.00	0.00%	$0.00	$71.98	$ (13.92)	$58.06	-

Table 7.10 – 2025 IRP Non-Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits

Resource Description	Variable O&M: Levelized Fuel ($/MWh)	Variable O&M: O&M ($/MWh)	Variable O&M: Capitalized Premium	Variable O&M: O&M Capitalized ($/MWh)	Total Resource Cost ($/MWh)	Credits: Tax Credits ($/MWh)	Credits: Total Resource Cost with PTC / ITC Credits ($/MWh)	Credits: Adjusted Total Resource Cost with PTC / ITC Credits
PV, 20 MW, Class 1-10	$ -	$0.00	0.00%	$0.00	$0.00		-	-
Portland North Coast	$ -	$0.00	0.00%	$0.00	$76.45	$ (25.15)	$51.30	$10.31
Southern OR	$ -	$0.00	0.00%	$0.00	$66.54	$ (25.15)	$41.39	$8.32
Walla Walla	$ -	$0.00	0.00%	$0.00	$69.74	$ (25.15)	$44.59	$8.96
Goshen	$ -	$0.00	0.00%	$0.00	$64.59	$ (25.15)	$39.44	$7.93
Wasatch Front	$ -	$0.00	0.00%	$0.00	$61.38	$ (27.63)	$33.75	$6.78
Wyoming East	$ -	$0.00	0.00%	$0.00	$64.79	$ (27.63)	$37.16	$7.47
PV, 200 MW, Class 1-10	$ -	$0.00	0.00%	$0.00	$0.00		-	-
Portland North Coast	$ -	$0.00	0.00%	$0.00	$51.72	$ (25.15)	$26.57	$5.34
Southern OR	$ -	$0.00	0.00%	$0.00	$44.87	$ (25.15)	$19.72	$3.96
Walla Walla	$ -	$0.00	0.00%	$0.00	$47.32	$ (25.15)	$22.17	$4.46
Goshen	$ -	$0.00	0.00%	$0.00	$43.86	$ (25.15)	$18.71	$3.76
Wasatch Front	$ -	$0.00	0.00%	$0.00	$41.71	$ (27.63)	$14.08	$2.83
Wyoming East	$ -	$0.00	0.00%	$0.00	$44.02	$ (27.63)	$16.40	$3.30
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	$ -	$0.00	0.00%	$0.00	$0.00		-	-
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	$ -	$0.00	0.00%	$0.00	$0.00		-	-
Wind Class 1-10, 20 MW	$ -	$0.00	0.00%	$0.00	$0.00		-	-
Portland North Coast	$ -	$0.00	0.00%	$0.00	$102.14	$ (23.46)	$78.68	$19.12
Southern OR	$ -	$0.00	0.00%	$0.00	$106.14	$ (23.46)	$82.68	$20.09
Walla Walla	$ -	$0.00	0.00%	$0.00	$104.46	$ (23.46)	$81.00	$19.68
Goshen	$ -	$0.00	0.00%	$0.00	$0.00	$ (23.46)	-	-
Wasatch Front	$ -	$0.00	0.00%	$0.00	$0.00	$ (25.77)	-	-
Wyoming East	$ -	$0.00	0.00%	$0.00	$0.00	$ (25.77)	-	-
Wind Class 1-6, 200 MW	$ -	$0.00	0.00%	$0.00	$0.00		-	-
Portland North Coast	$ -	$0.00	0.00%	$0.00	$41.47	$ (23.46)	$18.01	$4.38
Southern OR	$ -	$0.00	0.00%	$0.00	$47.92	$ (23.46)	$24.46	$5.94
Walla Walla	$ -	$0.00	0.00%	$0.00	$45.68	$ (23.46)	$22.22	$5.40
Goshen	$ -	$0.00	0.00%	$0.00	$48.49	$ (23.46)	$25.03	$6.08
Wasatch Front	$ -	$0.00	0.00%	$0.00	$47.93	$ (25.77)	$22.16	$5.38
Wyoming East	$ -	$0.00	0.00%	$0.00	$34.60	$ (25.77)	$8.83	$2.14
Wind Class 7, 200 MW	$ -	$0.00	0.00%	$0.00	$0.00		-	-
Offshore, Wind Class 12	$ -	$0.00	0.00%	$0.00	$0.00		-	-
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	$ -	$0.00	0.00%	$0.00	$0.00		-	-
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	$ -	$0.00	0.00%	$0.00	$0.00		-	-
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	$ -	$0.00	0.00%	$0.00	$0.00		-	-
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	$ -	$0.00	0.00%	$0.00	$0.00		-	-

Table 7.11 – 2025 IRP Storage Supply-Side Resources, Variable O&M, Total Cost and Credits

Resource Description	Variable O&M: Levelized Fuel ($/MWh)	Variable O&M: O&M ($/MWh)	Variable O&M: Capitalized Premium	Variable O&M: O&M Capitalized ($/MWh)	Total Resource Cost ($/MWh)	Credits: Tax Credits ($/MWh)	Credits: Total Resource Cost with PTC / ITC Credits ($/MWh)	Credits: Adjusted Total Resource Cost with PTC / ITC Credits
Li-Ion, 4-hour, 20 MW[1]	$ -	$0.00	0.00%	$0.00	$96.04	$ (32.40)	$63.64	-
Li-Ion, 4-hour, 200 MW[1]	$ -	$0.00	0.00%	$0.00	$82.42	$ (27.77)	$54.65	-
Portland North Coast	$ -	$0.00	0.00%	$0.00	$85.72	$ (29.44)	$56.28	$50.15
Southern OR	$ -	$0.00	0.00%	$0.00	$86.82	$ (29.99)	$56.82	$50.63
Walla Walla	$ -	$0.00	0.00%	$0.00	$84.07	$ (28.61)	$55.47	$49.42
Goshen	$ -	$0.00	0.00%	$0.00	$83.52	$ (28.33)	$55.19	$49.18
Wasatch Front	$ -	$0.00	0.00%	$0.00	$74.38	$ (38.14)	$36.24	$32.29
Wyoming East	$ -	$0.00	0.00%	$0.00	$72.55	$ (36.66)	$35.90	$31.98
Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW[1]	$ -	$0.00	0.00%	$0.00	$71.63	$ (23.69)	$47.94	-
Portland North Coast	$ -	$0.00	0.00%	$0.00	$74.44	$ (25.11)	$49.33	$48.84
Southern OR	$ -	$0.00	0.00%	$0.00	$75.38	$ (25.59)	$49.79	$49.29
Walla Walla	$ -	$0.00	0.00%	$0.00	$73.04	$ (24.40)	$48.63	$48.15
Goshen	$ -	$0.00	0.00%	$0.00	$72.57	$ (24.17)	$48.40	$47.92
Wasatch Front	$ -	$0.00	0.00%	$0.00	$64.76	$ (32.54)	$32.22	$31.90
Wyoming East	$ -	$0.00	0.00%	$0.00	$63.20	$ (31.27)	$31.93	$31.61
Li-Ion, 4-hour, 1000 MW[1]	$ -	$0.00	0.00%	$0.00	$79.77	$ (27.05)	$52.72	-
Li-Ion, 4-hour, 200 MW	$ -	$0.00	0.00%	$0.00	$82.42	$ (27.77)	$54.65	-
Portland North Coast	$ -	$0.00	0.00%	$0.00	$85.72	$ (29.44)	$56.28	$50.15
Southern OR	$ -	$0.00	0.00%	$0.00	$86.82	$ (29.99)	$56.82	$50.63
Walla Walla	$ -	$0.00	0.00%	$0.00	$84.07	$ (28.61)	$55.47	$49.42
Goshen	$ -	$0.00	0.00%	$0.00	$83.52	$ (28.33)	$55.19	$49.18
Wasatch Front	$ -	$0.00	0.00%	$0.00	$74.38	$ (38.14)	$36.24	$32.29
Wyoming East	$ -	$0.00	0.00%	$0.00	$72.55	$ (36.66)	$35.90	$31.98
Gravity Battery, 4-hour, 1000 MW	$ -	$0.00	0.00%	$0.00	$74.97	$ (33.10)	$41.87	-
Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	$ -	$0.00	6.27%	$0.00	$62.87	$ (24.62)	$38.25	-
Adiabatic CAES, 500 MW, 4000 MWh	$ -	$2.60	0.00%	$0.00	$65.03	$ (27.92)	$37.10	-
100-hour Iron Air	$ -	$0.00	0.00%	$0.00	$58.64	$ (37.40)	$21.24	-
Pumped Hydro, Two New Reservoirs, 4-hour	$ -	$0.58	0.00%	$0.00	$81.76	$ (33.01)	$48.75	-
Pumped Hydro, Two New Reservoirs, 10-hour	$ -	$0.58	0.00%	$0.00	$43.60	$ (18.40)	$25.20	-
Portland North Coast	$ -	$0.58	0.00%	$0.00	$45.73	$ (19.51)	$26.23	-
Southern OR	$ -	$0.58	0.00%	$0.00	$46.44	$ (19.87)	$26.57	-
Goshen	$ -	$0.58	0.00%	$0.00	$44.31	$ (18.77)	$25.54	-
Wasatch Front	$ -	$0.58	0.00%	$0.00	$38.03	$ (25.28)	$12.75	-
Wyoming East	$ -	$0.58	0.00%	$0.00	$36.86	$ (24.30)	$12.56	-
Pumped Hydro, One New Reservoir, 4-hour	$ -	$0.58	0.00%	$0.00	$79.49	$ (31.89)	$47.60	-
Pumped Hydro, One New Reservoir, 10-hour	$ -	$0.58	0.00%	$0.00	$38.02	$ (15.65)	$22.37	-
Pumped Thermal Energy Storage, 10-hour	$ -	$0.70	0.00%	$0.00	$68.76	$ (34.12)	$34.64	-
Pumped Thermal Energy Storage, 24-hour	$ -	$0.70	0.00%	$0.00	$126.33	$ (63.70)	$62.63	-

Table 7.12 - Glossary of Terms Used in the Supply-Side Resource Tables

Term	Description
Fuel	Primary fuel used for electricity generation or storage.
Resource	Primary technology used for electricity generation or storage.
Elevation (afsl)	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW)	For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition.
Resource Availability Year	The earliest year the Company would sign a contract for a Resource being studied in this IRP. If available prior to the development of this database, this defaults to IRP year.
Total Implementation Time	Number of years necessary to implement all phases of resource development and construction after signing a contract to build the Resource: permitting (e.g., air, land, water, and wildlife), maintenance contracts, owner's engineering, construction, testing, and grid interconnection.
Commercial Operation Year	Year when the Resource is available for generation and dispatch. It is based on the Resource Availability Year plus the Total Implementation Time.
Design Life (years)	Average number of years the resource is expected to be "used and useful.”
Base Capital ($/kW)	Total capital expenditure in dollars per kilowatt ($/kW) for the development and construction of a Resource including: direct costs (equipment, buildings, installation/overnight construction, commissioning, contractor fees/profit, and contingency), owner's costs (land, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, and owner’s contingency), and financial costs (allowance for funds used during construction (AFUDC), capital surcharge, property taxes, and escalation during construction, if applicable).
Var O&M ($/MWh)	Includes real levelized variable operating costs such as combustion turbine maintenance, water costs, boiler water/circulating water treatment chemicals, pollution control reagents, equipment maintenance, and fired hour fees in dollars per megawatt hour ($/MWh).
Fixed O&M ($/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment, and training.
Demolition Cost ($/kW)	Total cost to decommission and demolish the generating unit at the end of life in dollars per kilowatt ($/kW).

Term	Description
Full Load Heat Rate HHV (Btu/kWh)	Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis.
Efficiency	Typical operational round trip efficiency of energy storage of alternating current (AC) energy delivered to the grid divided by AC energy stored from the grid.
EFOR (%)	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates for a given Resource at the given site.
POR (%)	Estimated Planned Outage Rate for a given Resource at the given site.
Water Consumed (gal/MWh)	Average amount of water consumed by a Resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO2 (lbs/MMBtu)	Expected permitted level of sulfur dioxide (SO2) emissions in pounds of sulfur dioxide per million Btu of heat input.
NOx (lbs/MMBtu)	Expected permitted level of nitrogen oxides (NOx) (expressed as NO2) in pounds of NOx per million Btu of heat input.
Hg (lbs/TBtu)	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO2 (lbs/MMBtu)	Pounds of carbon dioxide (CO2) emitted per million Btu of heat input.

Table 7.13 - Glossary of Acronyms Used in the Supply-Side Resource Tables

Acronyms	Description
ACAES	Adiabatic Compressed Air Energy storage
AFSL	Average Feet (Above) Sea Level
ATB	Annual Technology Baseline
CAES	Compressed Air Energy Storage
CCCT	Combined Cycle Combustion Turbine
CCS	Carbon Capture and Storage (though storage costs are not included in the SSR Tables)
CCUS	Carbon Capture, Utilization and Storage (though utilization and storage costs are not included in the SSR Tables)
CF	Capacity Factor
CSP	Concentrated Solar Power
CT	Combustion Turbine
DF	Duct Firing
DOE	United States Department of Energy
EIA	Energy Information Agency
FGD	Flue Gas Desulfurization
GAIN	Gateway for Accelerated Innovation in Nuclear
HRSG	Heat Recovery Steam Generator
ICE	Internal Combustion Engine (reciprocating engine)
IGCC	Integrated Gasification Combined Cycle
ISO	International Standards Organization (Temperature = 59 degrees fahrenheit (°F) / 15 degrees Celsius (°C), Pressure = 14.7 psia/1.013 bar)
Li-Ion	Lithium Ion
LFP	Lithium Iron Phosphate (sub-chemistry of lithium-ion)

MW	Megawatt
NCM	Nickel Cobalt Manganese (sub-chemistry of lithium-ion)
NREL	National Renewable Energy Laboratory
OEM	Original Equipment Manufacturer
OSTI	Office of Scientific and Technical Information
OSW	Offshore Wind
PCCC	Post Combustion CO2 Capture
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
PC CCUS	Pulverized Coal retrofitted with Carbon Capture, Utilization and Storage
PHES	Pumped Hydro Energy Storage
PV Poly-Si	Photovoltaic modules constructed from poly-crystalline silicon semiconductor wafers
Recip	Reciprocating Engine
RTE	Round Trip Efficiency (typical operational AC to AC energy storage efficiency)
SCCT	Simple Cycle Combustion Turbine
SCR	Selective catalytic reduction
STG	Steam turbine generator

Resource Option Descriptions

The following are brief descriptions of each of the resources listed in Table 7.2 through Table 7.11. For all technology that is included in the 2024 NREL ATB, the ATB costs were used. For incremental items, a percentage difference between the technology with and without the incremental resource was used. Where data is available for an advanced technology innovation scenario[22], there is a resource row for that scenario.

Natural Gas, Internal Combustion Engine x4, renewable biofuel, with SCR & fuel tank – This is "a reciprocating internal combustion engine (RICE) power plant based on four large-scale natural-gas-fired engines. Each engine is rated nominally at 5.6 MW with a net capacity of 21.4 MW."[23] It is presented in the IRP as a 20 MW resource to meet Oregon's regulatory requirements for distributed generation resource, under the assumption that it could be derated to meet the requirements. The 24 hour fuel tank was added to the 2020 EIA Report's resource based on available market information on in ground gas tanks.

Natural Gas, Simple Combined Cycle Turbine (SCCT) Aero x 4 – This is "four of aeroderivative dual-fuel CTs in a simple-cycle configuration, with a nominal output of approximately 54 MW gross per turbine. After deducting internal auxiliary power demand, the net output of the plant is approximately 211 MW. Each CT's inlet air duct has an evaporative cooler

[22] https://atb.nrel.gov/electricity/2024/definitions#scenarios

[23] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf

to reduce the inlet air temperature in warmer seasons to increase the CT output. Each CT is also equipped with burners designed to reduce the CT's emission of NO_X. Included are SCR units for further reduction of NO_X emissions and CO catalysts for further reduction of CO emissions."[24]

Natural Gas, SCCT Frame "F" x 1, with SCR – This is "one industrial frame Model F dual fuel CT in simple-cycle configuration with a nominal output of 237.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 232.6 MW. The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. The CT is also equipped with burners designed to reduce the CT's emission of NO_X."[25] Although the 2020 EIA Report does not include an SCR for this resource, to be on par with the other IRP resources, the approximate cost of an SCR was added based on the cost difference on a percentage basis from previous IRP's.

Natural Gas, CCCT "H", 1x1, DF, with SCR – This is "one Model HL dual-fuel CT in a 1x1x1 single-shaft CC configuration. The CT generates approximately 453 MW gross and the STG generates 192 MW gross. After deducting internal auxiliary power demand, the net output of the plant is approximately 627 MW."[26]

Natural Gas, CCCT "H", 2x1, DF, with SCR – This is "a pair of Model H, dual-fuel CTs in a 2x2x1 CC configuration (two CTs, two heat recovery steam generators [HRSGs], and one steam turbine). Each CT generates approximately 436 MW gross; the STG generates approximately 393 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 1227 MW."[27]

Natural Gas, Δ for adding 95% CCS – This option reflects incremental changes for a greenfield "power plant w/ commercially available solvent-based post combustion CO_2 capture (PCCC) designed for 95% capture."[28] The 95% option was chosen because that is the most economic option available in the NREL ATB that meets the EPA 111 regulations.

Natural Gas, Δ for CT Brownfield construction – This option reflects incremental changes for construction of a resource at an existing powerplant site with the same technology.

Hydrogen, Δ for 100% Hydrogen burning capability – This option reflects incremental changes for a CT to burn a mixture of fuel up to 100% hydrogen.

[24] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf
[25] *Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies*, December 2019, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, February 2020 https://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2020/pdf/capital_cost_AEO2020.pdf
[26] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*, December 6, 2023, Sargent & Lundy, prepared for the U.S. Energy Information Administration's *Capital Cost and Performance Characteristics for Utility Scale Electric Power Generating Technologies*, January 2024. https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf
[27] Ibid 17
[28] 2024 ATB Excel Workbook, available at https://atb.nrel.gov/electricity/2024/data.

Hydrogen, Δ for Hydrogen storage, cavern, 80 bar, 1 week – This option reflects incremental changes for storing hydrogen underground in a solution-mined geologic salt dome. Hydrogen gas is compressed and stored at ambient temperature in at elevated pressure (70-190 bar). Salt domes only exist in a limited number of locations (~2000 salt caverns in North America with an average capacity of 10^5-10^6 m^3). There are at least two salt domes under development within PacifiCorp's area of operation. This assumes a "600 tons per day (TPD) pipeline throughput for 7-days at 80 bar; cushion gas is ~40% of volume."[29] In addition to the Pathways to Commercial Liftoff: Clean Hydrogen (Clean Hydrogen Liftoff Report), the Hydrogen and Fuel Cell Technologies Office Multi-Year Program Plan[30] was used for cost and technical data.

Hydrogen, Δ for Hydrogen storage, tanks, 500 bar, 24 hour – This option reflects incremental changes for storing hydrogen in tanks constructed above ground. "H_2 gas is compressed at ambient temperature to 300 – 700 bar. Storage capacity is limited due to the low volumetric density of H_2 at room temperature. Assumes 950 kg stored at 500 bar with 1 cycle per week."[31]

Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day – Also known as polymer electrolyte membrane, including balance of plant (BOP) costs, the "electrolyzer design is intended to represent the current state-of-the-art (2022) stacks with respect to catalyst loadings (3 milligrams per square centimeter [mg/cm2] total platinum group metal [PGM] loading) and material specifications."[32] Data from the DOE Hydrogen and Fuel Cells Program Record[33] was also used in the development of this resource.

Coal, CCS– These are retrofits of an existing conventional coal-fired boiler and steam-turbine generator resources with amine based post-combustion carbon capture technology. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output. The CCS would remove 90 percent of the carbon dioxide and would provide reductions in other emissions.[34]

Storage, Lithium Ion Battery – This is lithium-ion batteries rated at 20 and 200 MW capacities with 4-hour duration. The 20 MW option uses the ATB's "Commercial Battery" data, while the 200 MW option uses the ATB's "Utility-Scale" data.

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[29] Pathways to Commercial Liftoff: Clean Hydrogen, U.S. Department of Energy, Office of Technology Transitions: Hannah Murdoch; Office of Clean Energy Demonstrations: Jason Munster; Hydrogen & Fuel Cell Technologies Office: Sunita Satyapal, Neha Rustagi; Argonne National Laboratory: Amgad Elgowainy; National Renewable Energy Laboratory: Michael Penev, https://liftoff.energy.gov/wp-content/uploads/2023/05/20230523-Pathways-to-Commercial-Liftoff-Clean-Hydrogen.pdf

[30] Hydrogen and Fuel Cell Technologies Office Multi-Year Program Plan, Dr. Sunita Satyapal, U.S. Department of Energy, https://www.energy.gov/eere/fuelcells/hydrogen-and-fuel-cell-technologies-office-multi-year-program-plan

[31] ibid 20

[32] Badgett, Alex, Joe Brauch, Amogh Thatte, Rachel Rubin, Christopher Skangos, Xiaohua Wang, Rajesh Ahluwalia, Bryan Pivovar, and Mark Ruth. 2024. *Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolyzers*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-87625. https://www.nrel.gov/docs/fy24osti/87625.pdf.

[33] David Peterson, James Vickers, Dan DeSantis, *Hydrogen Production Cost From PEM Electrolysis – 2019,* February 3, 2020, https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/19009_h2_production_cost_pem_electrolysis_2019.pdf?Status=Master

[34] Carbon capture costs and parameters were the subject of discussion and feedback during the 2025 IRP public input meeting series.
See Appendix M, stakeholder feedback form #25 (NP Energy, LLC).
See Appendix M, stakeholder feedback form #44 (Sierra Club).

Storage, Δ double duration – This option reflects incremental changes for doubling the duration of a battery energy storage resource, modifiers on this row must be applied to the data in the appropriate resource row. Appropriate resources are limited to those utilizing lithium-ion energy storage, including lithium-ion energy storage collocated with other resources.

Storage, Δ for Co-Located Energy Storage – This option reflects incremental changes for lithium-ion energy storage collocated with another resource, modifiers on this row must be applied to the appropriate energy storage data.

Storage, Gravity Battery, 4-hour, 1000 MW – This is an estimate for any technology that uses the potential energy differential of a large mass, but excludes pumped hydro. Pumped hydro is a well-established technology and because of this there is more accurate data available for pumped hydro. Examples include dense weights lifted vertically, heavy rail cars moved up and down a steep track, or a piston displacing a fluid vertically. Costs were escalated from the 2023 IRP.

Storage, Adiabatic CAES – Compressed air energy storage (CAES) system consists of an air storage reservoir pressurized by a compressor similar to a conventional gas turbine compression section but driven by an electric motor coupled with an adiabatic power generation turbine. The compressed air powers the adiabatic turbine. Energy is stored by compressing air into the storage reservoir. Only the system sizes of 500 MW is included because that size was the lowest cost per kWh in the 2023 IRP. The air storage reservoir is an engineered tank. “Adiabatic” means the system does not burn natural gas to generate power.

Storage, Pumped Hydro, Two New Reservoirs – Also known as closed-loop pumped hydro, this technology pumps and releases water between a higher and a lower reservoir. It is modeled as a nominal 400 MW PHES system using a combination of natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 or 4 hours. The development and construction time is estimated at 5 years assuming that early permitting and development has occurred prior to contracting with PacifiCorp. The IRP uses ATB National Class 1 data.

Storage, Pumped Hydro, One New Reservoirs – Also known as an open-loop system, this technology pumps and releases water between a higher reservoir and a lower natural water body, usually a river. It is modeled as a nominal 400 MW PHES system using both natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 or 4 hours. The development and construction time is estimated at 5 years assuming that early permitting and development has occurred prior to contracting with PacifiCorp. The IRP uses ATB National Class 5 data.

Storage, 100-hour Iron Air – This is a low capital cost battery option with the trade off a low round trip efficiency. “While discharging, the battery breathes in oxygen from the air and converts iron metal to rust. While charging, the application of an electrical current converts the rust back to iron and the battery breathes out oxygen.”[35]

Storage, Pumped Thermal Energy Storage – This is a system using a storage tank of high temperature fluid to store energy. A resistive heater converts electric energy to heat energy in the

[35] https://formenergy.com/technology/battery-technology/

fluid. To generate electricity, the fluid boils water which powers a steam turbine attached to electric generator.

Solar, PV, Class 1 - 10 – This is ATB PV Class 1 through 10 (20 MW or 200 MW) solar photovoltaic resources using crystalline silica solar panels in a single axis tracking system. The 20 MW option uses the ATB's "Commercial" data, while the 200 MW option uses the ATB's "Utility-Scale" data. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 1-10, 20 MW – This is ATB "Distributed Wind, Large Turbine Technology Class." It is a wind resource of 1,500 kW turbines with 107 meter rotor diameter and 80 meter hub height. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 1-6, and 7200 MW – This is ATB Land-Based Wind technology configuration T1. It is a wind resource of 34 x 6 MW turbines with 170 meter rotor diameter and 115 meter hub height. A consultant was hired to provide location specific capacity factors for each node modeled in PLEXOS.

Wind, Wind Class 7, 200 MW – This is the same as wind classes 1- 6, but different wind conditions and cost data.

Wind, Offshore, Wind Class 12 – This is ATB "Floating Offshore Wind." It is a wind resource of 12 MW turbines with 216 meter rotor diameter and 137 meter hub height. Wind Class 12 represents the wind conditions off the coast of northern California and southern Oregon. The ATB lists a net capacity factor of 47% for Offshore Wind Class 12.

Nuclear, Small Modular Reactor or Advanced Reactor – This is a conceptual technology that could be a small modular reactor or small advanced reactor. "Modular" refers to a reactor that can be built off site and easily transported to the installation location, however scale of economy requires multiple modular reactors to share support facilities at a single powerplant site. Data is from the ATB and relies heavily on a DOE Office of Scientific and Technical Information, Gateway for Accelerated Innovation in Nuclear report[36] ("OSTI GAIN Report").

Nuclear, Δ for nuclear integrated thermal storage, 5 hours - This option reflects incremental changes for a system using a storage tank of high temperature fluid. To store energy, heat from a nuclear reactor is transferred in a heat exchanger to the storage fluid. To generate electricity, the fluid boils water which powers a steam turbine attached to electric generator. This method eliminates the resistive heater losses in the stand-alone thermal storage, and therefore has a much higher RTE.

[36] Abdalla Abou-Jaoude, Levi M Larsen, Nahuel Guaita, Ishita Trivedi, Frederick Joseck, and Christopher Lohse, Idaho National Laboratory; Edward Hoffman and Nicolas Stauff. Argonne National Laboratory; Koroush Shirvan, Massachusetts Institute of Technology; Adam Stein, Breakthrough Institute; Gateway for Accelerated Innovation in Nuclear (GAIN); *Meta-Analysis of Advanced Nuclear Reactor Cost Estimations*, July 2024, https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_107010.pdf

Nuclear, Large Light Water Reactor – This is a modern dual unit reactor similar to most of the existing utility reactors in the United States. Data is from the ATB and relies heavily on the OSTI GAIN Report.

Geothermal, Near Field Enhanced Geothermal System (NF-EGS) Binary – This is the ATB geothermal plant utilizing an 175°C thermal resource with 1.5 km wells and production well flow rates of 60 kg/s.[37]

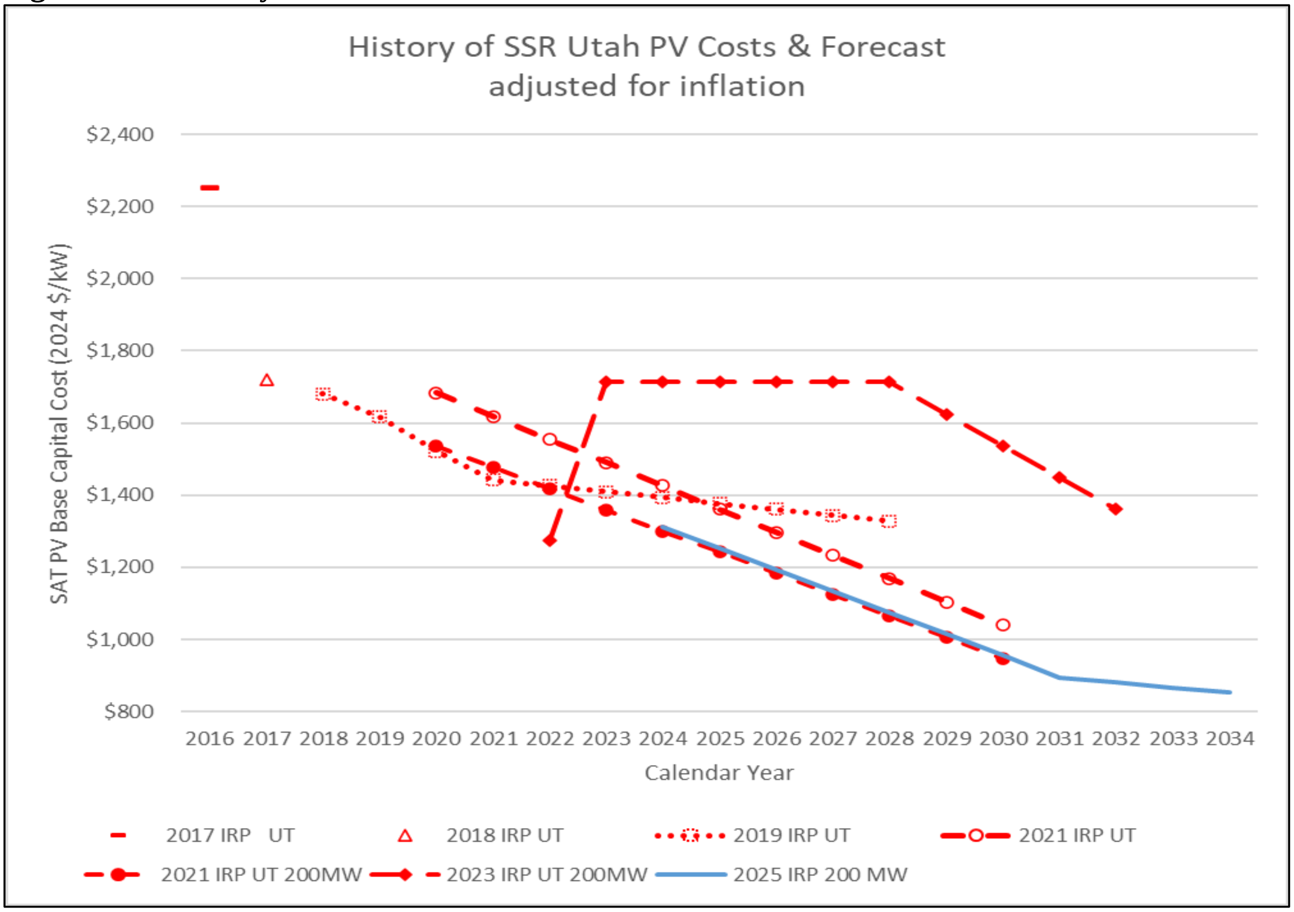
Locational Modifiers and Selected Cost Forecasts

Appendix A of the EIA reports contain cost modifiers for selected cities within each state, and Appendix B of the EIA reports contains locational modifiers for combustion turbines that are largely dependent on altitude and ambient temperatures. The ATB contains cost forecasts for most resource options in the SSR. For any resource option without a technology specific cost forecast, escalation is assumed to be level. These locational modifiers and cost forecasts are applied in PLEXOS. Cost forecast histories for selected resource types are shown in the following sections.

PV Cost Forecast History
Figure 7.1 shows a history of capital cost forecasts used in the SSR for PV resources in Utah from 2017 through 2023 IRPs (the red lines). The 2025 IRP Capital cost estimates for solar resources are based on the ATB forecast. The data from IRP's prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2025 IRP price forecast at the 200 MW scale in Utah. The observed market correction used in the 2023 IRP has been mitigated largely by federal policy changes and the forecast is essentially the same as the trend line of the 2021 IRP.

[37] Geothermal modeling was the subject of stakeholder feedback during the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus).
See Appendix M, stakeholder feedback form #41 (Nathan Strain).

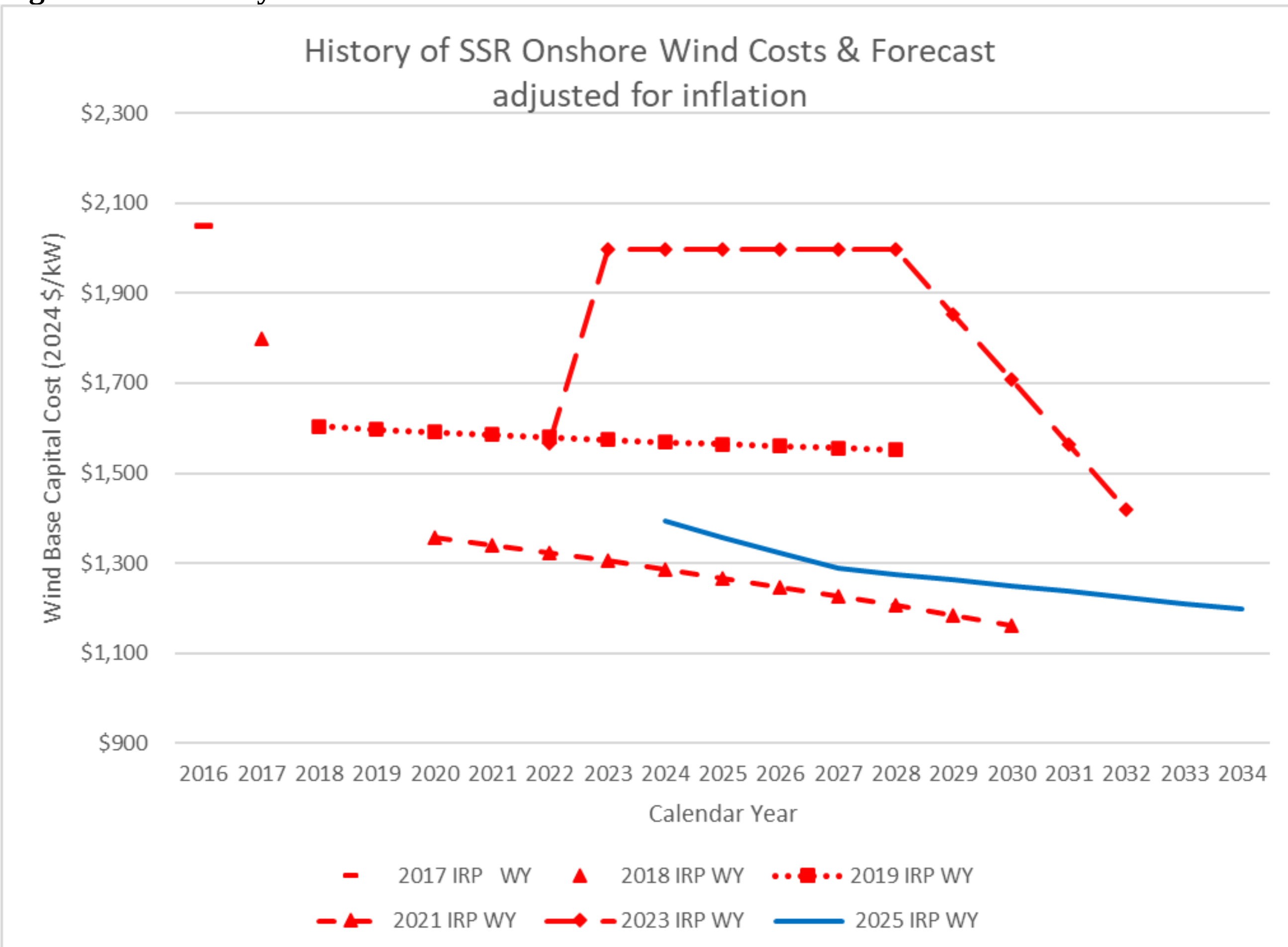
Figure 7.1 – History of SSR PV Cost & Forecast



Wind Cost Forecast History

Figure 7.2 shows a history of capital cost forecasts used in the SSR for resources in Wyoming from 2017 through 2023 IRPs (the red lines). The 2025 IRP Capital cost forecast for wind resources is based on the ATB forecast. The observed market correction used in the 2023 IRP has been mitigated largely by federal policy changes and the forecast is close to the trend line of the 2021 IRP.

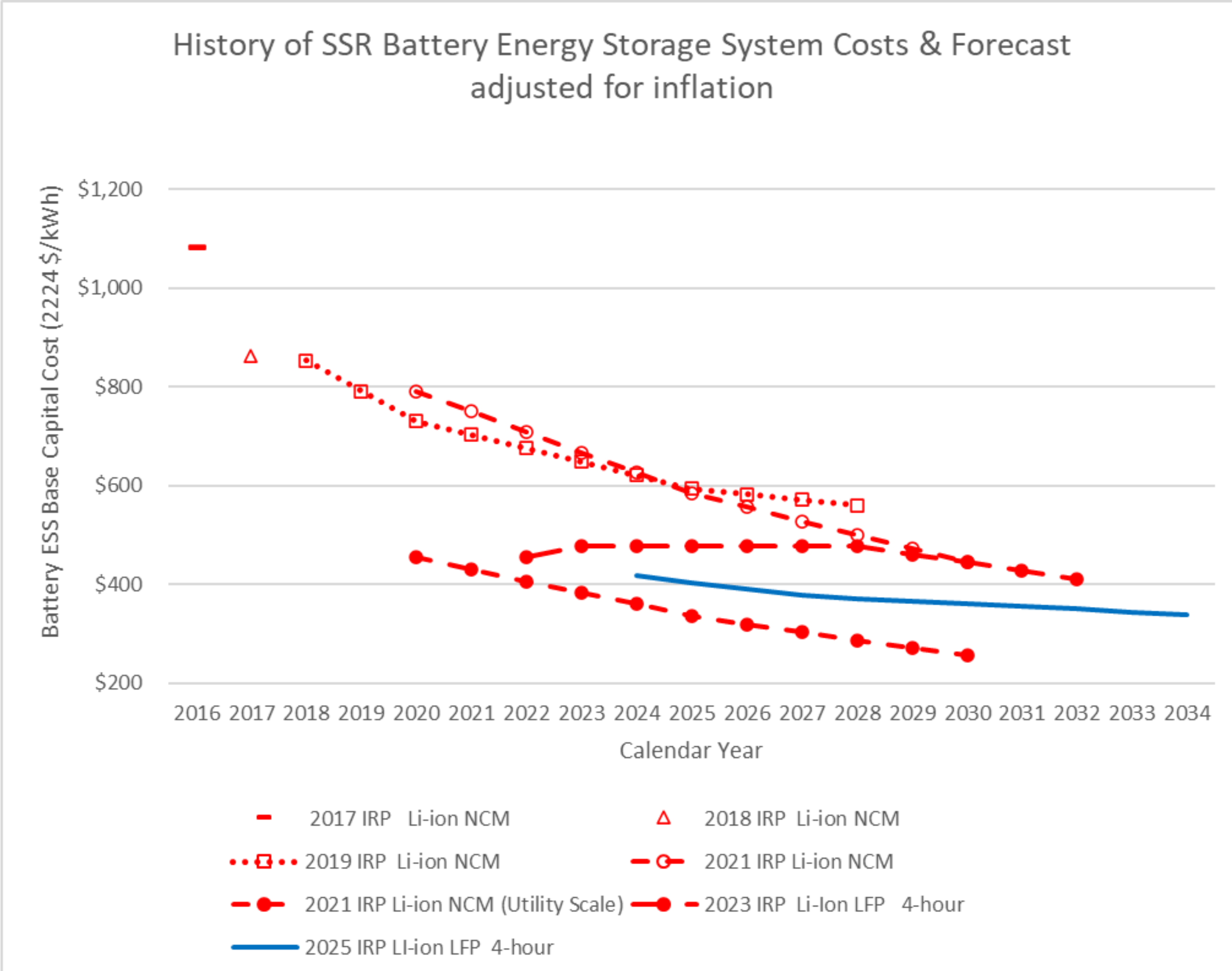
Figure 7.2 – History of SSR Wind Costs & Forecast



Energy Storage

Figure 7.3 shows a history of capital cost forecasts used in the SSR for BESS resources in Utah from 2017 through 2023 IRPs (the red lines). The 2025 IRP capital cost forecast for BESS resources is based on the ATB forecast. The data from IRP's prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2025 IRP price forecast at the 200 MW scale in Utah. The observed market correction used in the 2023 IRP has been partially mitigated by federal policy changes and the forecast costs are about midway between the less expensive 2021 IRP and the more expensive 2023 IRP.

Figure 7.3 – History of SSR Battery Energy Storage System Costs & Forecast



Utility-scale Energy Storage Resources

PacifiCorp has contracted for the following utility-scale energy storage resources:

- Faraday solar and storage (525 MW solar, 150 MW battery storage with 4-hour duration) is a project supporting customer clean energy goals under Utah Schedule 34.
- Green River solar and storage (400 MW solar, 400 MW battery storage with 4-hour duration) is a project that was originally part of the final shortlist in the 2020 All-Source Request For Proposals. An amendment to the contract expanded the battery from 200 MW with two-hour duration to 400 MW with four-hour duration.
- Dominguez Grid (200 MW battery storage with four-hour duration) is a stand-alone energy storage resource.
- Enterprise/Escalante/Granite Mountain East/Iron Springs storage: each of these contracts is an 80 MW battery storage resource with four-hour duration. Battery storage is being added at existing solar resources, and will use surplus interconnection. A surplus interconnection allows for resources to be added at any existing interconnection location so long as the total output to the grid is kept within the existing interconnection capacity.

As a result of the contracts described above, PacifiCorp expects to bring more than one gigawatt of energy storage resources online by the summer of 2026.

Demand-Side Resources

Resource Options and Attributes

Source of Demand-Side Management Resource Data

PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2025-2044, which provided DSM resource opportunity estimates for the 2025 IRP. The study was conducted by Applied Energy Group (AEG) on behalf of the company. The CPA provided a broad estimate of the size, type, location and cost of demand-side resources.[38] For the purpose of integrated resource planning, the DSM information from the CPA was converted into supply curves by type of resource (i.e. energy-based energy efficiency and demand response) for modeling against competing supply-side alternatives.

Demand-Side Management Supply Curves

DSM resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (e.g. products and quantities) based on each resource’s competitiveness against alternative resource options.[39] Due to the timing of the 2025 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2025 DSM program acquisition targets. To ensure that the 2025 IRP analysis is consistent with existing and planned demand response and energy efficiency acquisition levels (i.e., Class 1 & 2 DSM), expected DSM savings in each state were fixed for calendar year 2025. In 2026, energy efficiency resources were optimized to reflect ongoing program experience and knowledge of current market conditions and timing challenges, to develop near terms levels of selected acquisition.

As with supply-side resources, the development of DSM supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to DSM curves include:

- Resource quantities available in each year either in terms of megawatts or megawatt-hours, recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year of the planning period;
- Persistence of resource savings (e.g., energy efficiency equipment measure lives);
- Seasonal availability and hours available (e.g., irrigation load control programs);
- The hourly shape of the resource (e.g., load shape of the resource); and
- Levelized resource costs (e.g., dollars per kilowatt-hour per year for energy efficiency, or dollars per megawatt over the resource’s life for demand response resources).

[38] The 2025 Conservation Potential Study is available on PacifiCorp’s IRP Support & Studies web page: www.pacificorp.com/energy/integrated-resource-plan/support.html.

[39] Demand-side management modeling and methodology was a frequent topic of discussion in the 2025 IRP public input meeting series and in stakeholder feedback forms.
See Appendix M, stakeholder feedback form #17 (Oregon Public Utilities Commission).
See Appendix M, stakeholder feedback form #36 (Sierra Club).
See Appendix M, stakeholder feedback form #45 (Utah Clean Energy).

Once developed, DSM supply curves are treated like discrete supply-side resources in the IRP modeling environment.

Demand Response: DSM Capacity Supply Curves

The potential and costs for demand response resources were provided at the state level, with impacts specified separately for summer and winter peak periods. Prior to 2025, PacifiCorp has launched and expanded a number of demand response programs to acquire resource needs identified in the 2021 IRP update. Several demand response resources characterized as potential demand response resources in the previous IRP are now considered existing or planned demand response resources which will be effective in 2025.

Table 7.14 – Demand Response Existing and Planned Programs

Product	State	Existing or Planned Offering
Res – HVAC DLC	UT	Existing
Res – HVAC DLC	OR, WA	Planned
Res – EV Load Control	OR, WA, UT	Planned
Res – Battery DLC	OR, WA	Planned
Res – Battery DLC	ID, UT	Existing
C&I – Battery DLC	ID, UT	Existing
C&I – Third Party	OR, WA, UT	Existing
C&I – Third Party	ID	Planned
Ag – Irrigation DLC	UT, ID, OR, WA	Existing

Table 7.15 and Table 7.16 show the summary level demand response resource supply curve information, by control area. For additional detail on demand response resource assumptions used to develop these supply curves, see Volume 2 of the 2025 CPA.[40] Potential shown is incremental to the existing DSM resources identified in Table 7.15. For existing program offerings, it is assumed that the PacifiCorp could begin acquiring incremental potential in 2025. For resources representing expanded product offerings, it is assumed PacifiCorp could begin acquiring potential in 2026. New program offerings are assumed to be available in 2026 accounting for the time required for program design, regulatory approval, vendor selection, procurement and implementation.

Table 7.15 – Demand Response Program Attributes West Control Area,[41]*

Product	Summer		Winter	
	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)
Res – EV DLC	15.1	$412	15.1	$412
Res – DLC of Smart Home	0.1	$1,306	0.1	$686
Res – HVAC DLC	17.4	$175	81.7	$73

[40] The CPA can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

[41] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

Product	Summer		Winter	
	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)
Res – Pool Pump DLC	0.2	$742	0.1	$1,956
Res – Water Heater DLC	2.7	$134	4.0	$90
Res – Smart Thermostat	40.2	$37	28.9	$29
Res – Grid Interactive Water Heaters	14.6	$97	24.5	$66
Battery DLC	6.1	$31	4.9	$30
C&I – Third Party	8.5	$46	12.4	$54
Ag – Irrigation DLC	1.8	$24	0.0	$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

Table 7.16 – Demand Response Program Attributes East Control Area,[42]*

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
Res – EV DLC	24.8	$416	24.8	$416
Res – DLC of Smart Home	0.1	$1,601	0.3	$772
Res – HVAC DLC	234.2	$158	141.3	$272
Res – Pool Pump DLC	0.2	$834	0.1	$2,199
Res – Water Heater DLC	12.8	$175	17.5	$117
Res – Smart Thermostat	90.4	$38	50.2	$94
Res – Grid Interactive Water Heaters	1.1	$209	2.0	$139
Battery DLC	65.3	$36	65.2	$41
C&I – Third Party	66.6	$52	72.7	$50
Ag – Irrigation DLC	19.1	$29	0.0	$0

* Average levelized cost weighted by the 20-year cumulative potential in each state

Energy Efficiency DSM, Energy Supply Curves

The 2025 CPA provided the information to fully assess the potential contribution from DSM energy efficiency resources over the IRP planning horizon. The CPA analysis accounts for known changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g., cost-effectiveness criteria).

[42] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

DSM energy efficiency resource potential was assessed by state down to the individual measure and building levels (e.g., specific appliances, motors, lighting configurations for residential buildings, and small offices). The CPA provided DSM energy efficiency resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming[43]
- **Measure:**
  - 120 residential measures
  - 146 commercial measures
  - 105 industrial measures
  - 19 irrigation measures

- **Facility type:[44]**
  - 18 residential facility types
  - 28 commercial facility types
  - 30 industrial facility types
  - Two irrigation facility type

The 2025 CPA levelized total resource costs over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Costs include measure costs and a state-specific adder for program administrative costs for all states except Utah and Idaho. Consistent with regulatory mandates, Utah and Idaho DSM energy efficiency resource costs were levelized using utility costs instead of total resource costs (i.e. incentive and a state specific adder for program administration costs).

The technical potential for all DSM energy efficiency resources across all states except Oregon over the 20-year CPA planning horizon totaled approximately 15.1 million MWh.[45] The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (i.e. technical achievable potential). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 12.8 million MWh for all five states. The technical achievable potential for all six states, i.e. including Oregon, for modeling consideration is 17.2 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures by building type and state generated just over 50,500 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources

[43] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.
[44] Facility type includes such attributes as existing or new construction, single or multi-family, and income level for the residential sector. Facility types represent a combination of market segment and vintage and are more fully described in Volume 1 of the 2025 CPA.
[45] The identified technical potential represents the cumulative impact of DSM measure installations in the 20th year of the study period for California, Idaho, Washington, Wyoming, and Utah. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period. ETO provides PacifiCorp with technical achievable potential.

were consolidated into bundles, using ranges of levelized costs and net cost of capacity to reduce the number of combinations to a more manageable number.

Bundle development began with the energy efficiency technical potential identified by the 2021 CPA. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 21-year planning horizon. Consistent with the Northwest Power and Conservation Council's achievability assumptions in the 2021 Power Plan as, which typically assume that 85% of the technical potential could be acquired over the 20-year period.[46]

For Oregon, the company does not assess potential for the Energy Trust of Oregon (ETO). Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the DSM energy efficiency supply curves used in the development of the 2025 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp's six states.

Twenty-seven cost bundles, with a separate bundle reserved for home energy reports, were available across six states (including Oregon), which equates to 162 DSM energy efficiency resource supply curves. Table 7.17 shows the 21-year MWh potential for DSM energy efficiency net cost of capacity bundle categorization.

Bundles are classified based on their measure's temperature dependency, as either heating or cooling. A measure is considered temperature dependent if at least 25% of annual kWh savings are derived from temperature dependent end-uses. Measures that have both heating and cooling savings are classified based on whichever has greater volume. Measures that are not temperature dependent, such as lighting, are classified based on whichever season (summer or winter) the measure has a greater capacity contribution. Measures are then ranked based on their net cost of capacity ($/kW-yr) and assigned to a bundle with measures of a similar net cost. There is little need to differentiate bundles that will provide value in nearly all conditions. Measures with a net cost less or equal to zero have energy benefits that exceed their costs, such that their capacity value (reliability benefits) are "free." These measures are assigned to a zero-cost temperature-sensitive bin or a zero-cost non-temperature sensitive bin, which together comprise roughly half of all potential. For non-zero cost measures, roughly equal volumes are distributed among the remaining bundles of heating, cooling, summer, or winter measures. The number of each type of bundle varies by state depending on the potential and load profile used in each state.

[46] The Northwest's achievability assumptions include savings realized through improved codes and standards and market transformation, and thus, applying them to identified technical potential represents an aggressive view of what could be achieved through utility DSM programs.

Table 7.17 – 2045 Total Cumulative Energy Efficiency Potential by Cost Bundle Category (MWh)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
Cooling Measures	24,136	51,160	650,856	1,099,451	91,251	102,441
Heating Measures	1,395	29,701	871,974	334,629	76,938	50,792
Summer Measures	59	0	0	0	0	0
Winter Measures	46,268	127,649	1,398,502	1,903,672	241,406	208,044
Zero Cost Temperature Dependent Measures	30,050	76,633	295,605	1,400,650	130,845	112,492
Zero Cost Non-Temperature Dependent Measures	62,363	327,503	1,262,937	5,940,760	667,159	1,151,675

Cost credits afforded to DSM energy efficiency resources include the following:

- A state-specific transmission and distribution investment deferral cost credit (Table 7.18)
- Stochastic risk reduction credit[47]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[48]

Table 7.18 – State-specific Transmission and Distribution Credits (2024$)

State	Transmission Deferral Value ($/kW-year)	Distribution Deferral Value ($/kW-year)	Total
California	$5.83	$11.23	$17.06
Oregon	$5.83	$15.65	$21.49
Washington	$5.83	$18.93	$24.76
Idaho	$5.83	$23.11	$28.94
Utah	$5.83	$18.62	$24.46
Wyoming	$5.83	$9.61	$15.44

PacifiCorp relies on simulated load shapes tied to weather stations in PacifiCorp's service territory. Weather is a major driver of PacifiCorp's load and in any given month weather results in a range of high and low load conditions. Weather also impacts the hourly timing of energy efficiency savings particularly for measures that are weather dependent. As in the 2023 IRP, PacifiCorp has reshaped daily energy efficiency volumes to better align with seasonal variations in the load forecast. The highest demand for temperature-sensitive end use loads is expected to occur at the time of the winter and summer peaks in PacifiCorp's service territory. For temperature dependent measures, the simulated savings are proportionate with the temperature-sensitive load across in each month, so that the highest savings occur on the highest load days in the load forecast. To

[47] PacifiCorp develops this credit from two sets of production dispatch simulations of a given resource portfolio, and each set has two runs with and without DSM. One simulation is on deterministic basis and another on stochastic basis. Differences in production costs between the two sets of simulations determine the dollar per MWh stochastic risk reduction credit.

[48] The formula for calculating the $/MWh Power Act credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

capture the time-varying impacts of energy efficiency resources, each bundle uses an annual 8,760 hourly load shape. These shapes reflect measure-level annual energy savings, differentiated by state, sector, market segment, and end use. These hourly impacts are then aggregated for all measures in each bundle to create a single weighted average load shape for that bundle.

Distribution Efficiency

PacifiCorp continues to develop its CYME CYMDIST® (power flow software) investment in ways that improve engineering response time and, indirectly, distribution system efficiency. In the last biennial period, more than 275 large (Level 2 and Level 3) distributed energy resource (DER) applications were studied in CYME across the Pacific Power and Rocky Mountain Power service areas. This resulted in more than 34 MW (nameplate) of approved private generation across the company. Any energy savings resulting from these approvals across the service territory has not been determined.

These distribution energy efficiency activities were not modeled as potential resources in this IRP.

Transmission Resources

In developing resource portfolios for the 2025 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional information can be found in Volume I, Chapter 8.

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations.

Market transactions can encompass a wide variety of product types that can be classified as either forward (entered well in advance of delivery) or spot (entered no more than a day or two before delivery). Currently, the most commonly traded forward products are for heavy load hours (HLH) and/or light load hours (LLH), and are typically for calendar quarters (e.g. “Q3” spanning July, August, and September) or individual months. Other timeframes are less common, but could include super-peak products (noon to 8:00 p.m.). All of the common forward market products represent undifferentiated system power supplied at a point, but forward transactions can also be based on the costs, availability, options, and/or restrictions of specific physical resources. Some examples include slices of hydropower resources, or a tolling agreement for a natural gas-fired resource.

Examples of spot market transactions include day-ahead HLH and LLH products, day-ahead hourly transactions in the CAISO market, hour-ahead products, and intra-hour products facilitated by the Western Energy Imbalance Market (EIM).

In the next few years, two changes are coming that will change the landscape of markets in both forward and spot timeframes. First, the Western Resource Adequacy Program (WRAP) requires a showing of capacity resources a number of months in advance of the summer and winter seasons.

Current HLH and LLH market products will not count as capacity for WRAP unless the two counterparties agree to a capacity transfer, which may incur a higher cost or reduce a counterparty's willingness to sell. While contracts for physical resources would count as capacity for WRAP, it is unclear how much capacity of that sort is likely to be available, particularly as the many WRAP participants all seek to become compliant. Second, CAISO's Enhanced Day-Ahead Market (EDAM) will expand day-ahead resource optimization beyond the current CAISO footprint and will impact spot market participation. While EDAM takes over much of the optimization function in the day-ahead timeframe, to prevent leaning participants will be required to pass balancing tests to ensure they bring sufficient resources to meet their load, and this may necessitate transactions ahead of the EDAM.

In past IRPs, PacifiCorp included front office transactions (FOT) as proxy resource options, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the company cover short positions. Consistent with the current WRAP rules for unspecified-source purchases, FOTs are not included in the calculation of WRAP compliance in the 2025 IRP, so forward market purchases will not count as capacity. While the 2025 IRP does not allow FOTs to meet WRAP compliance requirements, PacifiCorp expects to continue pursuing economic short-term and intermediate term market opportunities that assist with WRAP compliance and/or balancing.

Spot market purchases and sales also provide opportunities to economically balance loads and resources. The economic opportunities are expected to be enhanced by the EDAM, relative to current operations, but it is unclear how the EDAM will compare to the IRP model's hourly balancing optimization of market purchase and sales volumes against static hourly market prices. In the EDAM and EIM, market prices are based on marginal supply and demand, so significant increases in supply are likely to reduce prices while increases in demand are likely to increase prices. When demand is high and begins to approach the limits of available supply, economic opportunities will diminish and adequate capacity will still be needed to participate. The 2025 IRP has incorporated historical relationships between daily prices, loads, and resource supply to better account for the impacts of supply and demand; however, it still relies upon a static forecast of prices that do not account for portfolio selections through time. With these various factors in mind, hourly market purchase volumes have been restricted during key hours on the top five load days within each month. These restrictions apply from 4:00 p.m. to 12:00 a.m. throughout the year, and in the winter an additional restriction applies in the morning, from 4:00 a.m. to 8:00 a.m. Outside of these hours (and all day on lower load days), market purchases are allowed up to modeled transmission limits. Similarly, hourly market sales volumes have been restricted to historical levels, to avoid increasing reliance on wholesale sales at favorable prices that may not persist in an organized market.

Chapter 5 describes the relationship of front office transactions (FOTs) to reliability and WRAP compliance, and FOTs are also considered a resource. Front office transactions can be made years, quarters or months in advance of use, however, they are generally committed to balance PacifiCorp's system on a balance of month, day-ahead, hour-ahead, or intra-hour basis. The terms, points of delivery, and products vary by individual market point.

Additional discussion of how FOTs are considered in the 2025 IRP, refer to Chapter 5 and Chapter 8.

CHAPTER 8 – MODELING AND PORTFOLIO EVALUATION

CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios.
- PacifiCorp used PLEXOS software to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and number of new resources that could be pursued to serve customers over the next 21 years.[1]
- The PLEXOS Long-Term (LT model) was used to generate initial portfolios and identify the resulting fixed costs. Each initial portfolio was evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three federal carbon dioxide (CO_2) policy scenarios (zero compliance requirements, a high price on CO_2 emissions, and compliance with current Environmental Protection Agency (EPA) CO_2 regulations). An additional CO_2 policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gases (SC-GHG). Taken together, there are five distinct price-policy scenarios (medium gas/current EPA regulations, medium gas/zero CO_2, high gas and coal/high CO_2, low gas/zero CO_2, and medium gas/social cost of greenhouse gases).
- Each initial portfolio was also evaluated in the Short-Term model (ST model) to establish system costs over the entire 21-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement (PVRR) which serves as the basis for selecting least-cost least-risk portfolios.
- A selection of competitive “variant” portfolios was analyzed using the other four price-policy scenarios in PLEXOS modeling to evaluate how each portfolio performs under differing future market and policy conditions.
- Taking into consideration stakeholder comments and regulatory requirements, PacifiCorp produced additional studies that examine the potential impact of portfolio options on the system.
- Informed by comprehensive modeling, PacifiCorp’s preferred portfolio selection process involves evaluating cost and risk metrics reported from ST reporting and stochastic modeling, comparing resource portfolios based on expected costs, low-probability high-cost outcomes, reliability, CO_2 emissions and other criteria.

[1] PacifiCorp’s IRP is typically modeled with a 20-year planning horizon, expanded in the 2025 IRP to 21 years to accommodate a specific Washington State requirement extending through 2045. Some discussions and data graphs in the 2025 IRP will refer to the standard 20-year horizon.

Introduction

IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting reliability requirements. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

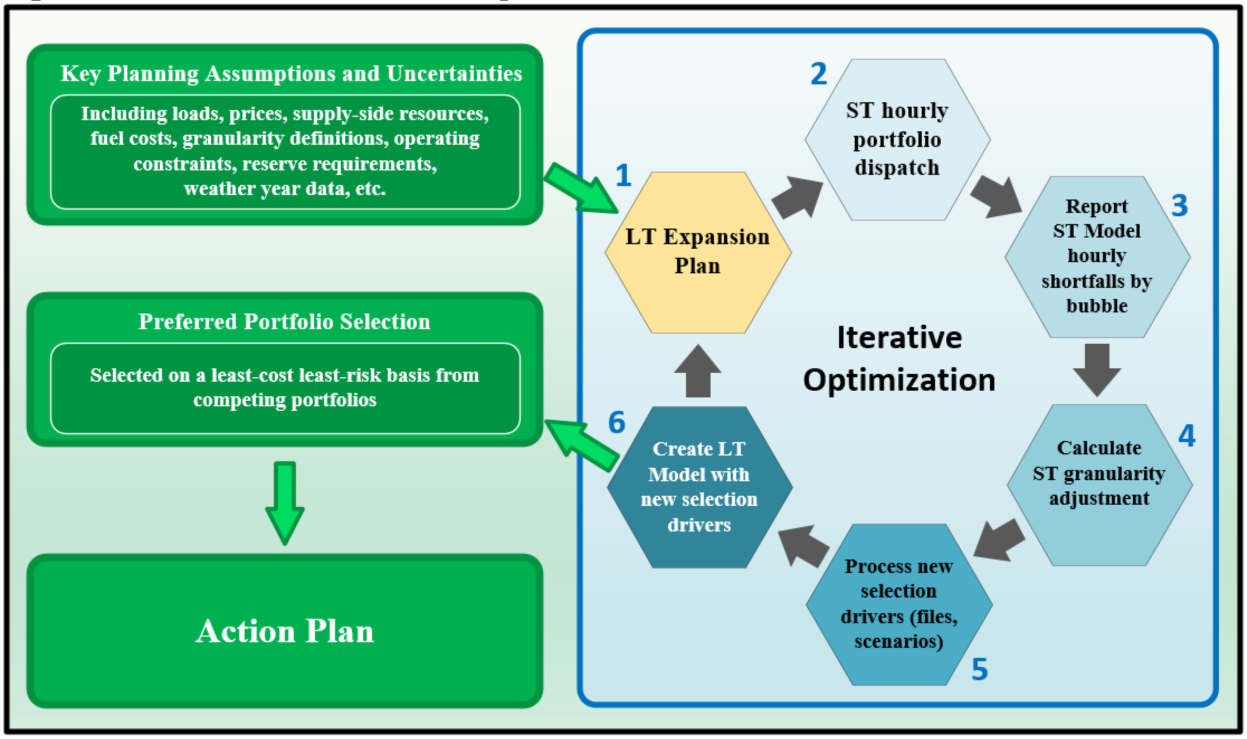
The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter describes the cases examined at each modeling and evaluation step. The results of PacifiCorp's modeling and portfolio analysis are summarized in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).

Modeling and Evaluation Steps

All IRP models are configured and loaded with the best available information at the time a model run is produced. Figure 8.1 summarizes the modeling and evaluation steps for the 2025 IRP. The process flow begins at left with the development of key inputs and assumptions. Next, studies are mathematically optimized using PLEXOS software tools[2], as illustrated in the six steps at right ("Iterative Optimization", highlighted in blue). Results are evaluated to determine the least-cost least-risk preferred portfolio from among all eligible portfolios. Finally, the preferred portfolio is used to develop the action plan.[3]

[2] PLEXOS technical modeling assumptions and parameters were discussed in the 2025 IRP public input meeting series and in stakeholder feedback.
See Appendix M, stakeholder feedback form #21 (Renewable Northwest).
See Appendix M, stakeholder feedback form #42 (First Principals Advisory).
[3] The topic of portfolio change was discussed extensively in the 2025 IRP public input meeting series. The modeling and evaluation steps explain how updated inputs are processed – such as updated resource costs as presented in Chapter 7 – resulting in new portfolio outcomes.
See Appendix M, stakeholder feedback form #13 (Joan Entwistle).
See Appendix M, stakeholder feedback form #15 (Sierra Club).
See Appendix M, stakeholder feedback form #27 (Vote Solar).

Figure 8.1 – Portfolio Evaluation Steps within the IRP Process



The portfolio development process in the 2025 IRP is an iterative process, whereby PacifiCorp completes initial Long Term capacity expansion modeling runs for each portfolio. Portfolios are evaluated for cost, reliability and compliance using the Short Term, dispatch focused, modeling results. Data regarding resource value and unserved energy quantities from the Short Term model is fed back into PLEXOS, and the next phase of iterative portfolio optimization is launched. Each cycle through the six steps is one modeling "phase". Iterations continue until the Long Term capacity expansion model has produced a portfolio that demonstrates no unserved energy in the Short Term dispatch model run, and then for several phases thereafter, so as to identify a range of potentially economic candidate portfolios. Each price-policy scenario and each candidate variant study follows this iterative optimization process. Once a completed portfolio phase achieves reliability, as measured using Short Term model results, evaluation is completed and results can be compared to other portfolios.

Overview of Steps in an Iterative Phase

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 short-term (ST) model. The ST model performs an hourly dispatch of the portfolio

Step 3

The ST model reports shortfalls as megawatts of unserved energy. These megawatts must be covered for each location (or "bubble") in the IRP transmission topology. Greater detail regarding use of these reported shortfalls to create the reliability adjustment is below.

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. Greater detail regarding the calculations which comprise the granularity adjustment is below.

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, if necessary, where shortfalls are represented as an additional load requirement and the granularity adjustment is represented as a cost adjustment (either an increase or decrease in costs) 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 4 blocks of hours per month over the 21-year horizon. This means the LT model groups similar hours into a block, calculates the average load and resource parameters specific to each block, and then concurrently solves the entire 21-year horizon. In contrast, the ST model concurrently solves (or dispatches) of a given week, or roughly 52 steps per year of 168 hours each, for a specified portfolio of resources as selected in the LT model. When PLEXOS optimizes the system in the 4-block LT view, it calculates a locational marginal price (LMP) specific to each block of hours. The value of a resource in the LT is equal to its generation in each block, multiplied by the LMP during that block specific to its location, and this value is part of the reported results based on the 48 blocks the LT evaluates during each year (4 blocks per month times 12 months). When the ST model dispatches the same resources at an hourly granularity, it calculates the LMP based on hourly conditions, multiplies by a resource's hourly generation, and reports the resulting value for each resource on an annual basis. The ST model also assigns specific resources to hold operating reserves necessary to meet reliability requirements, calculates the marginal price of reserves, and includes this as part of the reported resource value. The mathematical difference between the ST value and the LT value is the granularity adjustment.

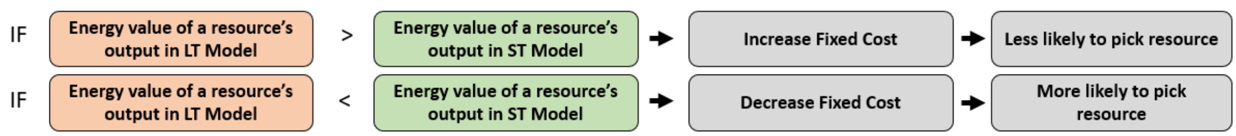
The 4 blocks used by the LT model include the top ten percent highest net load hours (load net of wind and solar generation), the highest wind generating hours, the highest solar generating hours, and the remainder of the hours. While these blocks are intended to help the LT model differentiate between key resource types, they can't capture the full range of hourly conditions.

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 8.2 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 8.2 – 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 2025 IRP, 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 hourly 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.

In order to avoid diluting singular hourly shortfalls across the entirety of a block, the highest monthly shortfall figure is taken, divided by 4 and applied to each hour in the top ten percent of highest net load hour block. The highest shortfall in a month is divided by 4 to avoid overshooting the total amount of resources needed. As an example, suppose the phase zero portfolio (the very first iteration of the six steps for a particular study) reports a maximum shortfall of 400 megawatts in Wasatch Front on June 8, 2032, at 8 PM. The 400 megawatt shortfall is divided by 4 to create a 100 megawatt adder to Wasatch Front load. This 100 megawatt adder is added to the base load file for all of the top ten percent net load hours in Wasatch Front in June of 2032, and phase 1 is run with the adjusted load file. If the portfolio selected in phase 1 reports a maximum shortfall of 100 megawatts in Wasatch Front in 2032, the same process is undertaken and 25 megawatts is added to all ten percent top net load hours, such that the load for that block is now 125 megawatts higher than the original phase zero 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 reliability and granularity adjustments result in an iterative loop from the LT model to the ST model and back to the LT model, with results that 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 no longer results in additional cost reductions.

Cost and Risk Analysis

Note – PacifiCorp is working to complete the stochastic analysis described below, and will include it in the final published IRP.

Sufficiently reliable resource portfolios developed by the LT model are simulated through stochastics to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. New to the 2025 IRP, stochastic risk modeling of resource portfolios is performed using actual historical conditions. These conditions, including weather patterns, thermal outages, fuel and market prices, hydro generation, and wind and solar generation profiles, are mapped to the historical dates underlying PacifiCorp's chaotic normal load forecast. PacifiCorp has 18 distinct years of historical data, and ran each portfolio using historical data for one specific historical year for all years of the 21-year horizon. The results from these runs are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR to guide portfolio selection.

Portfolio Selection

The portfolio selection process is based on modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the PVRR of system costs, assessed across a range of price-policy scenarios on a deterministic basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the deterministic PVRR with upper-tail stochastic risk PVRR. The final selection process considers cost-risk rankings, robustness of performance across pricing scenarios and other supplemental modeling results, including reliability, resource adequacy, compliance with all state laws/regulations, and CO_2 emissions data as an indicator of risks associated with greenhouse gas emissions.

Resource Portfolio Development

Resource expansion plan modeling, performed with the LT model, is used to produce resource portfolios with sufficient capacity to achieve reliability over the 21-year study horizon by evaluating groups of hours on an aggregated basis. Each resource portfolio is refined for reliability at an hourly granularity during the reliability assessment step as described above. Each portfolio is uniquely characterized by the type, timing, location, and number of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks.

Long-Term (LT) Capacity Expansion Model

In the 2025 IRP, the LT model is used to establish an initial portfolio under expected conditions (medium gas, zero CO_2), and then modified for each case, based on study parameters, to eliminate shortfalls and maintain reliability. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 21-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves plus a minimum planning reserve margin (PRM)[4] for each load area represented in the model.

The resource portfolios developed using the iterative approach outlined at the beginning of this chapter are appropriately reliable to its granularity and performance limitations. Operating reserve requirements include contingency reserves, which are calculated as 3% of load and 3% of generation. The planning reserve margin in the 2025 IRP is based on compliance with the Western Resource Adequacy Program (WRAP) at each load area in the topology, as provided in Figure 8.3.

If an early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirement in each period and location. The LT model may also select additional resources that are more economic than an existing generating resource. In the 2025 IRP, the model is simultaneously considering resource additions for reliable and economic system operation both before and after existing generation resources retire, as well as the years in which to retire existing resources.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. To enhance the ability of the LT model to differentiate key resource types and system conditions, for the 2025 IRP, each month was split into four blocks of hours based on load, wind, and solar, based on wind and solar generation profiles based on weather conditions during the specific days used to develop PacifiCorp's chaotic normal load forecast:

[4] The PLEXOS model uses 'capacity reserve margin' for what PacifiCorp has traditionally described as 'planning reserve margin' ("PRM"). While capacity reserve margin is slightly more precise, PRM is used in the 2023 IRP to reduce confusion over the use of multiple similar terms and because PRM is the industry standard term.

1. The top ten percent highest net load hours. 10% is approximately 70 hours per month, or an average of 2-3 per day, though some days may not have any hours in this group at all.
2. The top ten percent highest wind generation hours on a system basis.
3. The top ten percent highest solar generation hours on a system basis.
4. All other hours

The result of this modeling is to indicate to the LT model that wind and solar have very high availability in some hours, and very low availability in others. This would be expected to contribute to more moderate selections of wind and solar, as they will saturate some periods and have lower value. It would also be expected to contribute to selections of storage and peaking resources, targeted to cover periods in which wind and solar provide little generation supply.

PLEXOS LT model dispatch among blocks of hours in a month is not chronological, so it cannot constrain energy storage charging and discharging, except to ensure that over the course of a month these remain balanced. But within that limitation, PLEXOS determines generation and storage dispatch, optimal electricity flows between zones, and optimal market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

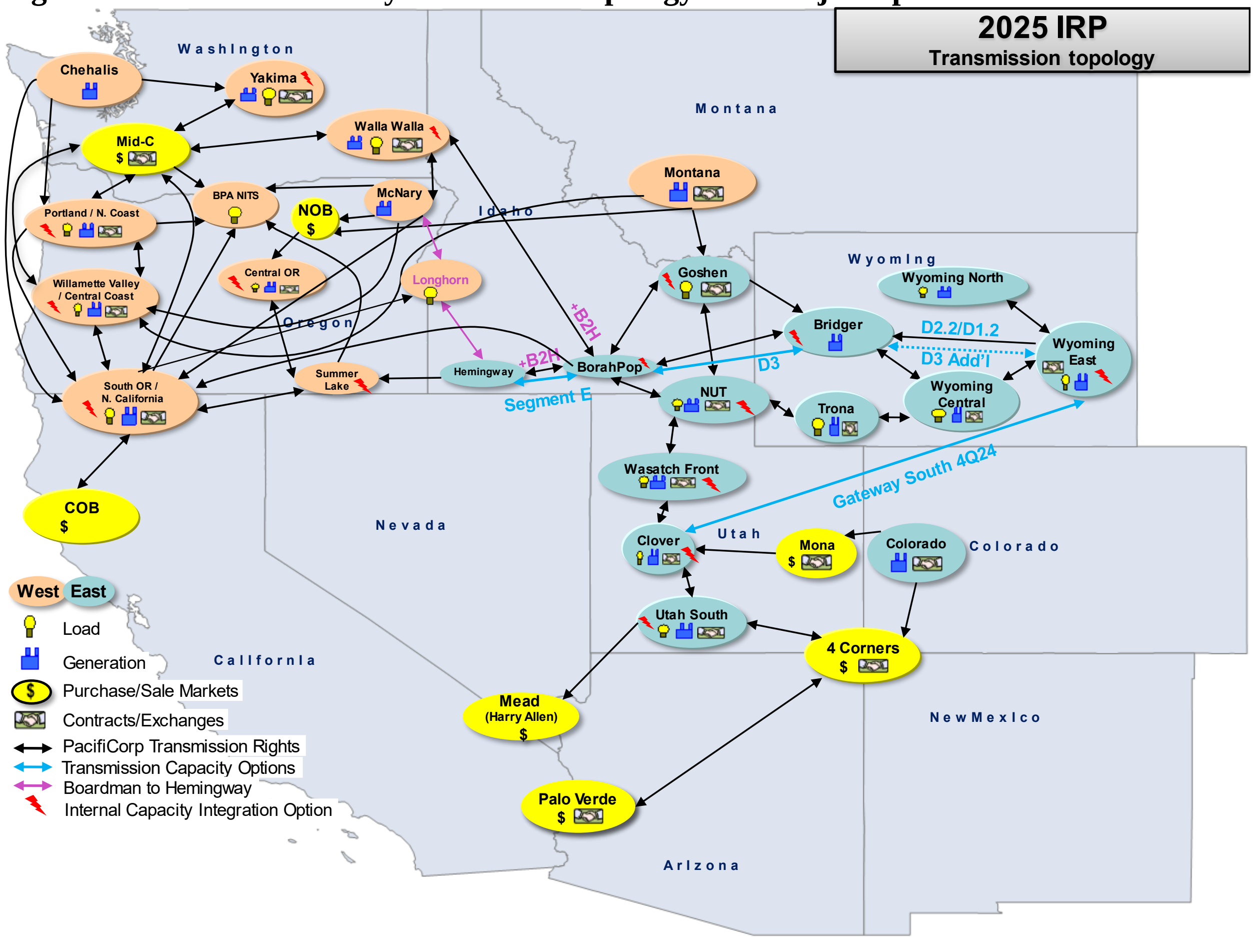
Key modeling elements and inputs for the LT capacity expansion model include the following:

Transmission System

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths.[5] Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.

[5] Continued interest was expressed on stakeholder feedback regarding the assumption of a Wyoming market hub to represent the opportunity afforded by certain transmission constraints. In light of the restrictions on the types of market products that can count toward WRAP capacity requirements, PacifiCorp's modeling does not count any short-term market products toward WRAP compliance, and has limited market purchases at all points during the highest load conditions in each month, to represent potential market liquidity limits. See Appendix M, stakeholder feedback form #39 (Western Resource Advocates).

Figure 8.3 – Transmission System Model Topology with Major Options



This map is for general reference only regarding IRP topology.
PacifiCorp is reevaluating the timing and needs analysis underlying B2H because of factors such as changed native load growth and a lack of capacity available on neighboring transmission systems to deliver to load pockets.

Figure 8.3 illustrates the 2025 IRP modeled topology where each transmission area or "bubble" is defined by any load and generation capability, it's location on the system and its connections to other bubbles.

Transmission Options

In addition to topology, Figure 8.3 illustrates modeled options for endogenous selection by the LT model. Over a span of three public input meetings, PacifiCorp presented information about transmission modeling as it was developed and presented interconnection and Cluster study results used to establish resource and transmission options based on the best available data.[6,7]

"Interconnection" requires modifications, additions, or upgrades to physically and electrically connect a generating facility to the transmission system. Which requirements apply can be

[6] Wildfire mitigation in the context of transmission was discussed in the 2025 IRP public input meeting series and stakeholder feedback. See Appendix M, stakeholder feedback form #18 (Wyoming Office of Consumer Advocate).
[7] Transmission modeling, cluster studies and details of resource-to-transmission relationships were discussed extensively during the 2025 IRP public input meeting series and in stakeholder feedback. See Appendix M, stakeholder feedback form #40 (Renewable Northwest).

impacted by the generation facility type, detailed project specifications, location, prior/existing generation facilities and load.

Studies needed to identify interconnection requirements are interdependent and extensive. Interconnection is carefully regulated for the safety, reliability, and efficiency of the electrical grid. Requests for interconnection made by any project are regulated and managed in various ways, such as:

- **Serial queue:** Signed agreements and near-final serial queue requests.
- **Transition Cluster:** Remaining serial queue requests and 2020 requests.
- **Cluster Study 1:** Spring 2021 requests.
- **Cluster Study 2:** Spring 2022 requests.
- **Cluster Study 3:** Spring 2023 requests
- **Colstrip:** Interconnection to jointly-owned Colstrip transmission assets.
- **Surplus:** Interconnection of additional resources at the same point as an existing generator, with aggregate output not exceeding the existing limit.
- **Provisional:** Interconnection study identifies maximum permissible output before transmission upgrades that are not yet in service.
- **Oregon Community Solar:** projects under 3MW seeking to participate in the Oregon Community Solar program.
- ***Informational Studies*:** Informational only, proposal and results are not considered part of later interconnection requests and cannot lead to an interconnection agreement.

The process of evaluating the viability of future projects is complex and time-consuming, resulting in many pending interconnection requests. In 2020, PacifiCorp transitioned from a serial queue study process (one generator at a time) to an annual cluster study process (one study for all new requests in a given area). In the 2023 IRP PacifiCorp significantly enhanced its study of resource and transmission potential to better align with project expectations and costs resulting from these advanced studies. For the 2025 IRP, PacifiCorp has transitioned to using cluster studies to indicate the earliest year a resource type is eligible for selection in any given location (as well as using recent cluster study data as compiled by PacifiCorp Transmission to indicate potential transmission upgrades and costs). Cluster studies are described further in Chapter 4.

Surplus Interconnections

Surplus interconnections add more generation to an existing interconnection without requiring additional transmission lines. However, while installed nameplate capacity is increased at a site, the total megawatt output at any given time at that location cannot exceed the original interconnection capacity.

Added generation can be of the same type and can take the form of additional generating unit or increased generation capability, such as wind repowering resulting in higher nameplate capacity than the existing interconnection. In the event an added resource is of a different type, a hybrid is created. For example, a hybrid resource combination of solar, wind and storage allow a higher net capacity factor among all three resources, increasing overall generation, while avoiding the need for added transmission.

PacifiCorp has submitted surplus interconnection requests to evaluate the addition of solar to several wind resource sites in Wyoming.

Transmission Costs
In developing resource portfolios for the 2025 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.

Resource Adequacy
In its 2025 IRP, PacifiCorp included the monthly planning reserve margin requirements from the Western Resource Adequacy Program (WRAP) in the LT model. The planning reserve margin applies in all periods and must be met by available resources within that area or imports from adjacent areas with excess resources available, subject to transmission constraints. While WRAP is expected to enhance reliability, the monthly capacity contribution values assigned to each resource may not be sufficient to meet hourly requirements in every location, so it does not eliminate the need for reliability assessment. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

Granularity and Reliability Adjustments
As detailed during the 2025 IRP public-input process, the granularity adjustment reflects the difference in economic value in resource options and transmission between an hourly 8760 cost calculation in ST modeling, and the monthly blocking representation used in the LT model.[8]

This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the block granularity smooths out many of the storage arbitrage opportunities and also doesn’t fully capture the effect of storage duration limits.

In parallel with the granularity adjustment, the reliability adjustment addresses unmet capacity needs by hour in the LT model portfolio selection. Much of the peak load hour requirements in mid-afternoon in the summer are adequately met by solar resources. However, resource requirements are driven by portfolio-dependent *net* load peaks (load less renewable resource output), which are harder for the LT model to identify.

While the granularity and reliability adjustments help direct the LT model to more cost-effective resources and a more reliable portfolio, in a single pass, the LT model cannot guarantee reliability at an hourly operational level. Marginal benefits decline as any resource type becomes a larger

[8] See Appendix M, stakeholder feedback form #17 (Oregon Public Utilities Commission) for responses to questions regarding modeling transmission and granularity adjustments. The method for evaluating granularity value for transmission is the same as for supply-side resources, in that the model reports values used for the granularity adjustments based on the resource’s contribution to reducing cost and risk.
See also Appendix M, stakeholder feedback form #36 (Sierra Club).

share of a portfolio, as it saturates the need in the hours it is available. A similar effect occurs with storage, where each incremental MW of system storage capacity must cover a longer duration.

Because of the performance limitations of capacity expansion optimization, the ST model is leveraged to refine the portfolio to achieve a final balanced and reliable mix of resources, as described under the Cost and Risk Analysis section of this analysis, further below.

Thermal Resource Options

Continuing best practice from the 2023 IRP, all majority-owned and operated coal plant sites are considered candidates for surplus interconnection in the 2025 IRP. Other renewable technologies can be added prior to the coal plant's retirement, with the aggregate of the existing and surplus resource output limited to the current maximum output of the coal resource. As a result, the LT model simultaneously evaluates the value of surplus resources both before and after the associated coal units retire, while at the same time evaluating when, or whether, they should retire.

Table 8.1 and Table 8.2 report the coal unit options modeled in the 2025 IRP, whereas Table 8.3 summarizes the options available for natural gas-fired units.

Table 8.1 – Majority-Owned Coal Generator Resource Options[9,10]

Jim Bridger Units 3 and 4	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal-CCS 2030						CCS+45Q												CCS	-	-	-
Dave Johnston 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028-2029/Gas Conv. 2029				-	Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dave Johnston 3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028				Retired																	
Dave Johnston 4	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-
Wyodak	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Gas	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-
Hunter 1-3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire Alt. Fuel-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Alt. Fuel	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-
Huntington 1-2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal 2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire Alt. Fuel-2030/2039 111(d)						Dual Fuel	-	-	-	-	-	-	-	-	Alt. Fuel	-	-	-	-	-	-
Coal CCS+SCR 2032								CCS+45Q												CCS	-

Key				
		Default/current operation	45Q	CCS
		Retirement Option		Alternative Fuel
		Gas conversion option		Assumed retired

[9] While 111(d) compliance can be met with dual fuel operations in 2030-2038, due to engineering uncertainty and modeling complexity, starting in 2030 100% of the fuel input for these options comes from natural gas or alternative fuel. For Hunter and Huntington, which are not located in proximity to natural gas pipeline transport, the alternative fuel modeled in the 2025 IRP is biodiesel.

[10] After the filing of the 2023 IRP Update on March 31, 2024, a change occurred in the timing of implementation of carbon capture on Jim Bridger Units 3 and 4. CCS assumption for these units is updated for the 2025 IRP. See Appendix M, stakeholder feedback form #5 (Powder River Basin).

Table 8.2 - Minority-Owned Coal Generator Resource Options

Minority-Owned Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Colstrip 3		PAC share moves to Unit 4																			
Colstrip 4		*Includes Unit 3 share*																			
Craig 1																					
Craig 2																					
Hayden 1																					
Hayden 2																					

Key: Default/current operation; Assumed retired

Table 8.3 - Natural Gas Generator Resource Options[11]

Chehalis	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Cofire/non-emitting 2030																					
Currant Creek	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hermiston 1/2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2039/Alt. Fuel				-	-	-	-	-	-	-	-	-	-	-	-						
Jim Bridger Units 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lakeside 1	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lakeside 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton Units 1 and 2	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2026 thru 2045		Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Naughton Unit 3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas-2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gadsby Steam 1-3	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gadsby CTs 4-6	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Gas 2028 thru 2045		-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Key: Default/current operation; Retirement option; Assumed retired; Alternative Fuel; Current (Coal)

New Resource Options

Demand-Side Management

Energy efficiency resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand response resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

Wind and Solar Resources

[11] PacifiCorp has insufficient detail at this time to evaluate alternative fueling options at its Chehalis and Hermiston natural gas-fired facilities, particularly in light of possible impacts on cost-allocation and market participation, and has adopted Action Plan item 1h to advance options for potential implementation by 2030.

Proxy wind and solar resources available for inclusion in the preferred portfolio are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources are based on the weather conditions from the same historical days used to develop the load forecast.

The ability for wind and solar resources to reliably meet demand over time is impacted by the forecasted profiles, along with mix of other resources in the portfolio.

Non-Emitting Resources

Four non-CO_2-emitting thermal resources are considered: nuclear projects, small renewable fuel peaking resources, geothermal resources, and non-emitting hydrogen peaking units leveraging on-site electrolysis with 24 hours of tank storage. Nuclear resources and geothermal are characterized by continuous operation, with the Natrium project combining this operation with storage in the form of heat stored as molten salt. In contrast, peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls. The small renewable peaking resource for the 2025 IRP is assumed to use biodiesel or renewable diesel, both of which are commercially available. While combustion of these fuels releases CO_2 it is not derived from fossil sources and is eligible to meet compliance requirements in both Oregon and Washington.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

- Energy take – generation or extraction of energy from a storage reservoir for a specified period;
- Energy return – energy used to fill (or charge) a storage reservoir; and
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and variable costs, if applicable.

Market Purchases

Market purchases are transactions by the company's front office and represent short-term firm agreements for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., future months or quarters, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or the exchange provides a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all of the short-term firm physical power products, differing by delivery pattern and delivery period, which are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the contribution of short-term firm market purchases is accounted for in the portfolio-development process.

Capital Costs

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. Use of nominal levelized revenue requirement costs is an established methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the nominal levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes, income taxes, and demolition costs over the life of the investment. The result is an annuity or annual payment that remains constant such that the PVRR is identical to the PVRR of the nominal requirement when using the same nominal discount rate.

General Assumptions

Study Period and Date Conventions

PacifiCorp executes its 2025 IRP models for a 21-year period beginning January 1, 2025 and ending December 31, 2045. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, except for coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period after ceasing coal-fired operation at the end of the prior year.

Inflation Rates

The 2025 IRP simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.18 percent is assumed. This escalation rate reflects the average of annual inflation rate projections for the period 2025 through 2045, using PacifiCorp's September 2024 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the 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 2025 IRP is 6.69 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[12] PVRR figures reported in the 2025 IRP are reported in 2024 dollars.

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

CO_2 Price Scenarios

PacifiCorp used three different CO_2 price scenarios in the 2025 IRP—zero, high, and a price forecast that aligns with the social cost of greenhouse gases (SCGHG), plus a scenario reflecting compliance with current federal regulations including the currently published EPA rule 111(d). The high greenhouse gas scenario is derived from forecasts of greenhouse gas costs in Washington and California, but is applied like a federal obligation throughout the system starting in 2030. Impacts in the scenario which includes current federal regulations also become relevant in 2030, as coal-fired resources must select between retirement, carbon capture, or co-firing by this time.

The SCGHG scenario is in compliance with Washington RCW 19.280.030 including an adjusted cost of greenhouse gas emissions reflecting inflation, defined by the Washington Utilities and Transportation Commission.[13] The social cost of greenhouse gas emissions is assumed to apply in all years of the study horizon. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

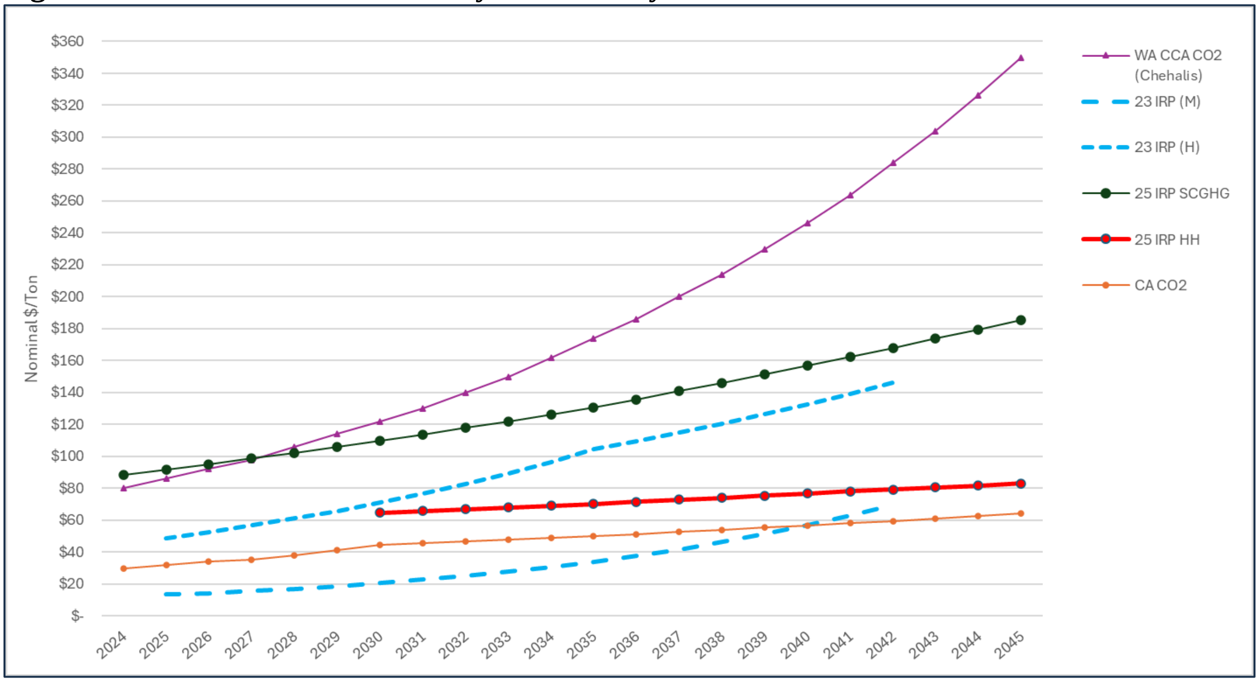
In all scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021.[14] This is in addition to the assumed federal CO_2 policy represented in the zero, high, and social cost of greenhouse gas scenarios described above. The modeled allowance cost is based on the allowance cost cap identified by the Washington Department of Ecology, and starts at $88 metric ton in 2024.[15]

[13] Washington Utilities and Transportation Commission, Order 05, Docket No. U-190730,July 25, 2024. Available online at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=27&year=2019&docketNumber=190730 (Accessed 11/8/2024).

[14] Stakeholder feedback requested modeling Chehalis without consideration of Washington's Climate Commitment Act. Notwithstanding that certain commissions have declined to allow the company to recover these costs, the company continues to incur these costs, which are therefore modeled. See Appendix M, stakeholder feedback form #19 (Wyoming Office of Consumer Advocate).

[15] Washington Cap-and-Invest Program 2024 Annual Allowance Price Containment Reserve Tier Price and Price Ceiling Unit Price Notice. December 2023. Available online at: https://apps.ecology.wa.gov/publications/documents/2302066.pdf (Accessed 11/8/2024).

Figure 8.4 – CO_2 Prices Modeled by Price-Policy Scenario



Wholesale Electricity and Natural Gas Forward Prices

For 2025 IRP modeling purposes, five electricity price forecasts were used: the official forward price curve (OFPC) and four scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

At the time PacifiCorp's 2025 IRP modeling inputs were prepared, the September 2024 OFPC was the most current OFPC available. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflects market forwards at the close of a given trading day.[16] As such, these 36 months are market forwards as of September 2024. 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 price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAxmp[17] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Scenarios using high or low gas prices do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market.. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also

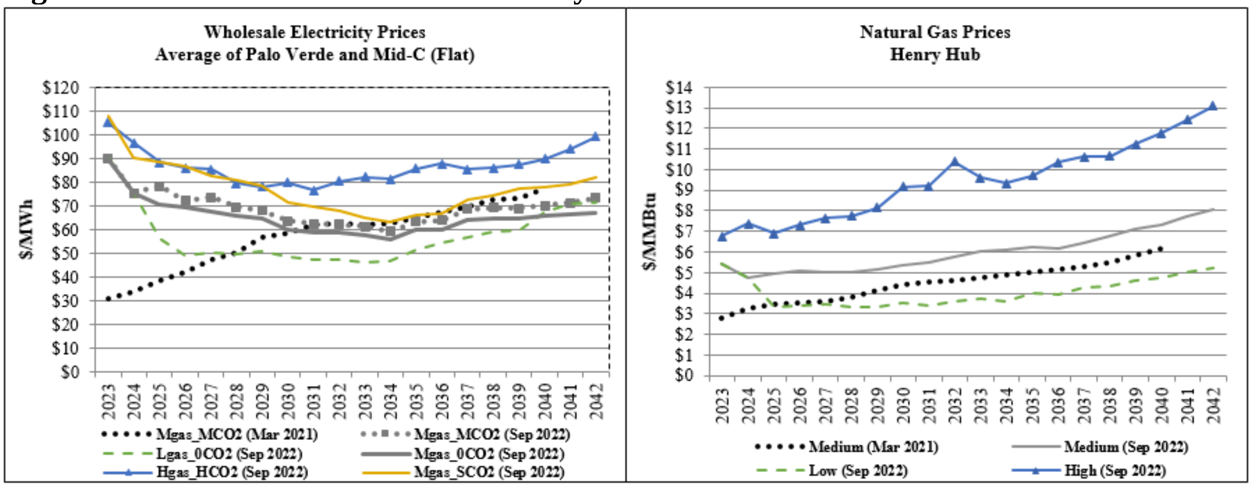
[16] The September 2024 OFPC prompt month is November 2024; October 2024 would be traded as "balance of month" when the OFPC is released.
[17] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

derived from an expert third-party forecast. Similarly, the SCGHG scenario does not incorporate any market forwards since that greenhouse gas policy represents an alternative view that applies throughout the study period.

New to the 2025 IRP, in response to stakeholder feedback and requests related to volatility in coal pricing, the high gas and market price-policy scenario also includes an elevated coal fuel supply cost. This represents risks such as supply-chain issues as well as the potential for increased transportation costs or other increased variable coal costs which are not present in the base forecast for coal pricing.[18]

Figure 8.5 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2025 IRP.

Figure 8.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Cost and Risk Analysis

Short-Term (ST) Schedule Model

The ST model uses the same common input assumptions described for the LT model coupled with the portfolio selected by the LT model. LT results provide the initial capacity expansion plan for the ST model to dispatch.

[18] Coal supply, costs and risks were discussed in the 2025 IRP public input meeting series and stakeholder feedback. In the 2025 IRP, PacifiCorp considers base coal cost assumptions, the Jim Bridger Long-term Fuel Plan sensitivity, and coal-related variant studies. For stakeholder feedback and responses:
See Appendix M, stakeholder feedback form #28 (Utah Citizens Advocating Renewable Energy).
See Appendix M, stakeholder feedback form #29 (Utah Clean Energy).
See Appendix M, stakeholder feedback form #30 (Katie Pappas).
See Appendix M, stakeholder feedback form #31 (Jane Myers).
See Appendix M, stakeholder feedback form #32 (Sara Kenney).

Reliability Assessment and System Cost

The ST model begins with a portfolio from the LT model that has not yet been refined to reflect the reliability and compliance needs of a particular study (e.g., a particular sensitivity or price-policy scenario). The ST model is first run at an hourly level for 21 years in order to retrieve two critical pieces of data: 1) shortfalls by hour, and 2) the value of every potential resource to the system that is specific to the portfolio itself, and the other input assumptions, such as the price-policy scenario.

As discussed at the start of the chapter, these data points are fed back into the LT model to prompt endogenous selections of resources that lead to a reliable portfolio.

Resource Value

PLEXOS calculates a locational marginal price (LMP) specific to each area in each hour that is based on supply and demand in that area and available imports and exports on transmission links to adjacent areas. This is also known as a shadow price. PLEXOS also calculates the marginal price specific to ancillary services (i.e., operating reserves) in each hour. PLEXOS then multiplies these prices by a resource's optimized energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. In an organized market, this would represent the expected payments based on market-clearing prices.

When variable costs (such as fuel, emissions, and VOM) are subtracted out, the result is a resource's "net revenue". Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, modeling capabilities, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated, and marginal prices will again reflect the variable cost of an available resource.

Portfolio Refinements

While many resource options are evaluated, utility scale generation resources are mostly restricted to two circumstances: surplus or replacement resources at generators that are eligible to retire, and new resources at locations with interconnection or transmission upgrade options. New for the 2025 IRP, small resources (those with a capacity of fewer than 20 megawatts) are eligible to be sited within any of the load regions and unconstrained by new transmission requirements, as PacifiCorp's studies have shown resources that are sufficiently small and sized consistent with the local grid can be feasible without large transmission investments. Like small resources, PacifiCorp has added a "local" battery option within each of the load areas which is available for selection at a higher cost than those co-located with other resources (per the supply side table).

These interconnection and transmission upgrade options are limited and can be expensive. Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in “firm” capacity creates a need for additional interconnection capacity elsewhere, and a key strategy is maximizing the “firmness” of each MW of interconnection capacity to provide greater value. For this reason, the modeling of replacement and expansion resources is not limited by the nameplate of resources being added, but rather to by an hourly maximum generation constraint. As such, the model is able to select any combination of resources leading to a smoothing of hourly capacity among various renewable or peaking/firm resources. Within a transmission constraint, batteries are assumed to always be co-located with other resources, enabling them to shift energy accumulated during periods of high solar radiance, wind speed or other generation, and increase the effective capacity contribution of the combination of resources in a given location.

<u>Portfolio Cost</u>

The second run of the ST model produces an optimized dispatch of each portfolio to reflect least-cost operations while meeting all requirements and adhering to modeled constraints. The ST model’s hourly granularity means that this system cost will be highly accurate, taking into account operational nuances that are obscured in the less granular LT model. This in turn means that when evaluating the constellation of all competitive portfolios, the comparison will be based on appropriate relationships among all system components to yield an accurate PVRR.

<u>Additional Measures</u>

- Annual and energy not served (ENS)
- Annual CO_2 emissions.

Stochastic Modeling

Once unique resource portfolios are developed using the LT and ST models, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. For the 2025 IRP, stochastic risk modeling of resource portfolio alternatives is performed with the ST model.

The standard ST model inputs reflect a normalized view of future conditions that reflects the typical range of outcomes. For stochastic modeling in the 2025 IRP, alternative inputs are used that reflect conditions analogous to actual results in a specific historical. Stochastic inputs for the 2025 IRP have been expanded and now include wind and solar generation profiles, along with the energy efficiency profiles for weather-sensitive bundles, in addition to the variables reflected in past IRPs: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.

Volume II, Appendix H (Stochastics) discusses the methodology for developing the stochastic inputs for the 2025 IRP.

Note – PacifiCorp is working to complete the stochastic analysis described above, and will include it in the final published IRP.

Monte Carlo Simulation

For the 2025 IRP, PacifiCorp has data reflecting eighteen discrete annual conditions, specifically the historical data and variances from 2006-2023 for each of the stochastic inputs. By running eighteen ST model scenarios covering each of these conditions, results can encompass the full range of conditions. However, each of these ST model scenarios represents conditions from a single year repeating in every year of the study horizon, with slight differences from year to year to account for days of the week, plus load growth, climate change impacts on load and hydro, and changes in the resource portfolio. For instance, every year from 2025-2045 would be a dry hydro year (below average). There are benefits to compiling the results in this way, as it will be easier to identify specific historical weather conditions that are leading to high costs and ENS. But to produce portfolio performance measures, Monte Carlo sampling of the annual results may be appropriate, particularly for assessment of multi-year compliance requirements such as renewable portfolio standards (RPS) and Washington's Clean Energy Transformation Act (CETA).

Stochastic Portfolio Performance Measures

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from the Monte Carlo annual draws include:

- Stochastic mean PVRR
- Upper-tail Mean PVRR
- 5th, 90th and 95th percentile PVRR
- Standard deviation
- Risk-adjustment (5% of the 95th percentile)
- Energy Not Served (ENS)
- Environmental Compliance: Washington CETA and Oregon HB 2021

<u>Stochastic Mean PVRR</u>

The stochastic mean PVRR is the average of system net variable operating costs among 20 iterations, combined with the nominal levelized capital costs and fixed costs corresponding to the LT model for any given resource portfolio. The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, long term contracts, system balancing market purchase expenses and sales revenues, reserve deficiency costs, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources are calculated on a nominal-levelized basis. Other components in the stochastic mean PVRR include CO_2 emission costs for any scenarios that include a CO_2 price assumption. The stochastic mean PVRR, is not used directly in portfolio selection; instead, the more granular ST PVRR serves as the base measure of net system cost, modified appropriately by stochastic risk.

<u>Upper-Tail Mean PVRR</u>

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the three highest production costs on a net present value basis. The portfolio's fixed costs, taken from the LT model, are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

5th and 95th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 20 Monte Carlo iterations. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 20 Monte Carlo iterations. The production cost is expressed as a net present value of annual costs over the IRP horizon. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Risk-Adjustment

The model outcomes of the 20 stochastic samples are used to calculate a risk-adjustment measuring the relative risk of low-probability, high-cost outcomes. This measure is calculated as five percent of system variable costs from the 95th percentile. This metric expresses a low-probability portfolio cost outcome as a risk premium based on 20 Monte Carlo simulations for each resource portfolio and applied to the hourly-granularity deterministic PVRR. The rationale behind the risk-adjusted PVRR is to have a consolidated cost indicator for portfolio ranking, combining the most precise available system cost and high-end cost-risk concepts.

Energy Not Served (ENS)

In past IRPs, the use of the reduced granularity in the PLEXOS MT model limited the relevance of the reported ENS. In the 2025 IRP, the ST model's full 8760 granularity is being reflected in stochastic analysis, so reported ENS is representative of a portfolio's performance in the real-world historical conditions that underlie the stochastic inputs.

Environmental Compliance

With the 2025 IRP's shift to stochastics based on calendar year conditions, it is now possible to evaluate annual compliance requirements under a realistic range of conditions. This has been less relevant when evaluating annual RPS compliance as the Company's recent IRPs have generally exceeded compliance requirements by a significant margin, particularly when banking and inter-year flexibility are taken into account. Because the level of compliance is significantly higher under Washington's CETA statute and Oregon HB 2021, year-to-year variations in renewable resources and load may result in shortfalls when conditions are less favorable than normal. Under CETA, compliance is based on multi-year periods and allows for use of unbundled renewable energy credits for up to twenty percent of the obligation through 2044, so overall compliance can be achieved without achieving full compliance in the least favorable years, though it may require more resources than under normal conditions. Oregon HB 2021 measures compliance within each calendar year, but allows the Oregon Public Utility Commission to consider the extent that excess emissions from generation used to meet load is a result of lower than expected generation from nonemitting resources, so it is unclear what level of compliance certainty is appropriate. The stochastic results will indicate the level of compliance over a range of conditions, and should help identify the types of resources that can increase compliance during less favorable conditions.

Forward Price Curve Scenarios
Preferred portfolio variants developed during the portfolio-development process are analyzed under up to five price-policy scenarios.

Other PLEXOS Modeling Methods and Assumptions

Transmission System

The base transmission topology shown in Figure 8.3 is used in each of the PLEXOS models. Any transmission upgrades selected by LT and ST model processes that provide incremental transfer capability among bubbles in this topology are part of the portfolio and thus included in normalized and stochastic ST optimizations.

Resource Adequacy

The reality of modeling large complex power systems in a world of significant variable resources is that availability must be compared to requirements in all modeled periods, as measurements only at peak do not adequately establish system reliability. For the 2025 IRP, PRM and resource contributions based on WRAP are used as part of portfolio selection, but this is not part of resource dispatch. In addition to WRAP compliance, ST reliability modifications to the portfolio evaluate hourly resource availability and system requirements to directly determine reliability shortfalls and any additional resource need at the hourly level.

Energy Storage Resources

Storage resources have many potential advantages, including storage for frequency regulation, grid stabilization, transmission loss reduction, reduced transmission congestion, renewable energy smoothing, spinning reserve, peak-shaving, load-levelling, transmission and distribution deferral, and asset utilization.

Each PLEXOS model dispatches storage resources endogenously, subject to any applicable constraints, for example requirements to charge from onsite solar or for the combined solar and storage output and reserves to remain within a single interconnection limit. The model can deploy energy storage for the most cost-effective uses, including any combination of load ramping and leveling, reserve carrying, and to complement the benefits of renewable resource additions, particularly co-located renewables.

Other Cost and Risk Considerations

In addition to reviewing the risk-adjustment, ENS, and CO_2 emissions data, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

Fuel Source Diversity
PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios

based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, storage resources, DSM resources and market purchases.

Customer Rate Impacts

To derive a rate impact measure, PacifiCorp computes the change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the risk adjusted PVRR results from the models and capital costs on a nominal levelized basis. While this approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for rate-making purposes.

Market Reliance

To assess market reliance risk, PacifiCorp quantifies market purchases for each portfolio allowing comparisons among cases in Chapter 9 (Modeling and Portfolio Selection Results). Starting in the 2021 IRP, market purchases were restricted compared to past IRPs, as described in Volume I, Chapter 7 (Resource Options).

Portfolio Selection

Portfolios are measured for relative performance regarding system costs, risk-adjusted system costs, ENS, CO_2 emissions, and compliance with state and federal policies. The risk-adjusted PVRR accounts for relative risk of volatility among portfolios.

Each portfolio under examination at a given step in the analysis is compared based on cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include stochastic PVRR, risk-adjusted PVRR, ENS and emissions. As noted above, market reliance risk was also evaluated. The comparisons of outcomes are detailed, ranked, and assessed in the next chapter.

Additional quantitative analysis can be performed to further assess the relative differences among top-performing portfolios; qualitative analysis can also be considered where appropriate during portfolio selection on the basis of known factors that could not be readily captured in models.

Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps.

During the final screening process, the results of any further resource portfolio developments will be ranked by risk-adjusted PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the five price-policy price curve scenarios. Resource portfolios with the lowest risk-adjusted PVRR receive the highest rank. Final screening also considers system cost PVRR data from the PLEXOS models and other comparative portfolio analysis. At this stage, PacifiCorp reviews additional metrics from the models looking to identify if ENS and CO_2

emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted PVRR basis.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2025 IRP, organized here into major development categories:

- Initial Portfolios – including all Variants
    - Initial portfolios and variants are evaluated under three distinct sets of jurisdictional requirements:
        - Utah/Idaho/Wyoming/California
        - Oregon
        - Washington
    - Integrated Portfolios incorporates selections from the top performing initial portfolios under each set of jurisdictional requirements
    - The preferred portfolio is selected based on the integrated portfolio results
- Jurisdictional Analysis[19]
- Sensitivity Cases

Additional portfolio detail can be found in Volume II, Appendix I (Capacity Expansion Results).

Initial Portfolios

Informed by the public-input process, the initial cases endogenously explore a multitude of potentially significant interactions among retirement options including the potential to convert coal units to natural gas operations, install carbon-capture equipment on coal-fired facilities, or retire units during the study horizon. In addition to the core functionality of selecting the optimal timing, size, and location of proxy resources, PLEXOS also optimizes existing natural gas and coal retirements. The modeling continues to include a wide range of transmission options for selection, assessed simultaneously with all other competing elements. The initial portfolios also consider how resource selections change with price-policy assumptions that deviate from the medium natural gas price and zero CO_2 price assumptions used to develop many resource portfolios. All the initial portfolios rely on the combined capabilities of the optimization models within PLEXOS.

Portfolios generated with SCGHG price-policy assumptions are consistent with RCW 19.280.030 in Washington.

Table 8.4 provides the initial portfolio definitions for this IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Volume II, Appendix I (Capacity Expansion Results).

[19] Includes informational portfolios that are not eligible for selection as the state-wide preferred portfolio.

Table 8.4 – Price-Policy Case Definitions

Price-Policy	Existing Coal[b]	Existing Gas[b]	Other Existing Resources	Proxy Resources[c]
MN	Optimized	Optimized	End of Life	All allowed
MR	Optimized	Optimized	End of Life	All allowed
LN	Optimized	Optimized	End of Life	All allowed
HH	Optimized	Optimized	End of Life	All allowed
SC	Optimized	Optimized	End of Life	All allowed

(a) Thermal coal and gas resources are endogenously optimized for retirements, conversions and technology installations.
(b) Optimized proxy portfolio selections include renewables, off-shore wind, storage, natural gas, transmission, DSM, purchases and sales, etc.

All portfolios consider variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or CCUS retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing.

Certain additional cases were developed based on stakeholder feedback and state requirements to evaluate the impacts of specific future scenarios. These cases are all eligible to be adopted into the preferred portfolio if the analysis warrants their inclusion. In the 2025 IRP, there are the following variant portfolio selection cases as shown in Table 8.5:

Table 8.5 – Portfolio Variants

Variant	Description	Refer to Case
No CCS	No coal units are able to select CCS technology	-
No Nuclear	No nuclear resources are eligible for selection	-
No Coal 2032	All coal must retire or gas convert by January 1, 2032	-
Offshore Wind	Counterfactual to the Preferred Portfolio selection	-
All Coal End of Life	Continue 2025 coal technology	See the No CCS variant
No New Gas	No new gas resources allowed	See the Preferred Portfolio
Force All Gas Conversions	Force all coal-to-gas options	See the No Coal 2032 variant
No Forward Technology	No nuclear, hydro storage or biodiesel peaking	See the No Nuclear variant

Each variant case begins with the same PLEXOS dataset inputs and assumptions, and adds the constraints to either force a selection, disallow a specific resource or resource type, delay a project or force retirements as outlined below.

No CCS

This variant removes the CCS option at Jim Bridger 3 and 4. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if CCS is not a commercially viable option.

No Nuclear

This variant removes the Natrium™ demonstration project in 2030 and all other nuclear resources from available resource options. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of the variant is to evaluate resource alternatives in the absence of nuclear resource options. Additionally, this sensitivity seeks to evaluate the potential risk if nuclear resources are unable to achieve online and operating status for any reason.

No Coal 2032

In this variant all coal plants are assumed to retire no later than 2032. Coal plants are eligible to run past 2032 if gas conversion is selected at that plant. No CCUS options are available in this variant. The endogenous portfolio was integrated using the same method as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if external factors required coal plants to cease coal-fired operations by 2032.

Offshore Wind

Offshore wind was available for selection in the preferred portfolio beginning in 2033, based on the timing of necessary transmission upgrades. As offshore wind has not been endogenously selected in the preferred portfolio, a minimum of 1000 MW was required to be selected in this variant. Additionally, the necessary onshore transmission required to enable offshore wind was available for selection by offshore wind or by any other appropriately located proxy resources to ensure that co-located resources could be selected to complement the offshore wind and that it is competitive with other options. This counterfactual is used to assess system impacts and the magnitude of the costs and benefits associated with offshore wind.

All Coal End of Life

> *The No CCS run selects coal at all current coal sites and does not choose to retire any eligible units. Please refer to the No CCS variant for results.*

In this variant all coal plants are assumed to run as coal-fired units using the technology present on the plant as of January 1, 2025, and are not eligible to retire during the study horizon unless otherwise required to do so. Dave Johnston units 1-3 along with Naughton units 1 and 2 still retire or cease coal-fired operation as necessary. Minority owned coal plants are also assumed to retire as necessary. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if majority-owned coal resources were allowed to run as coal-fired to end-of-life.

No New Gas

The unconstrained integrated MN case does not select new natural gas resources. Please refer to the Preferred Portfolio for results.

This variant assumes no new gas resources are allowed to be selected. This does not include the conversion of coal plants from coal-fired to gas-fired. The purpose of this variant is to evaluate the cost and risk impacts of replacing new gas resources selected in the preferred portfolio with other energy resources..

Force All Gas Conversions

The No Coal 2032 selected all plants eligible for gas conversion. Please refer to the No Coal 2032 variant for results.

In this variant all coal plants eligible for gas conversion are forced to do so. The gas converted coal plants are allowed to retire endogenously, and the portfolio is re-optimized. The purpose of this variant is to evaluate the cost and risk impacts associated with gas conversion becoming the only future option for all coal-fired plants.

No Forward Technology

The No Nuclear study did not select hydrogen storage, biodiesel peaking or nuclear resources. Please refer to the No Nuclear variant for results.

In this variant all nuclear, hydrogen storage and biodiesel peaking resources are removed from the preferred portfolio and the portfolio is re-optimized. The purpose of this variant is to evaluate the cost and risk impacts of limited new resource types becoming available in the future.

Integrated Portfolios

Portfolio integration involves combining resource selections from each of the initial jurisdictional portfolio results under a given price-policy scenario or variant. Every initial jurisdictional portfolio evaluates the entire system and all proxy resource options, plus the constraints specific to that jurisdiction. For proxy resources that can be allocated to any jurisdiction, the integration step adopts the largest quantity of each individual resource by year that was included in any of the jurisdictional studies (UT/ID/WY/CA & OR & WA). Because of interconnection limits, it is generally not possible to sum the selections across the various jurisdictions, and the overall quantity might not be economic. For resources that are specific to a single jurisdiction, including demand-side resources and existing thermal resources, the integration step adopts the quantity from that specific jurisdiction's initial portfolio result.

Resources that are shared among multiple jurisdictions are allocated based on the amounts selected in their initial jurisdictional portfolio – if a resource was not picked in a jurisdiction's initial portfolio, that jurisdiction would not be allocated any of that resource. The resource is split among those jurisdictions in which it was selected, with any quantity selected in multiple jurisdictions, allocated between them based on their share of system load (the System Generation or SG share under the 2020 Protocol), or the equivalent including only those jurisdictions for whom that quantity of a resource was selected. An example is provided below in Table 8.6.

Table 8.6 – Portfolio Integration Resource Example

Jurisidiction	Approximate Load Share	Initial Portfolio Selection (MW)	1st 20 MW shared by all Allocation Step 1	Next 30 MW shared by OR/WA Allocation Step 2	Last 50 MW WA only Allocation Step 3	Total Allocation (MW)
UT/ID/WY/CA	60%	20	12	n/a	n/a	12
Oregon	30%	50	6	22.5	n/a	28.5
Washington	10%	100	2	7.5	50	59.5
Total	100%		20	30	50	100

In this way, resource allocations are fixed based on jurisdictional selections in the year in which they are built and do not change over time. Where a proxy resource has additions in multiple years, only the quantity added in a given year is allocated, based on portfolio selections in that year. This integration process is applied to every initial portfolio.

Allocation among the jurisdictions has the potential to result in compliance shortfalls, as a portion of the resources that were identified for compliance may be allocated to other jurisdictions. If shortfalls are identified after running through the ST model, the initial portfolio analysis for that jurisdiction can be repeated with the shortfall quantity added to the jurisdictional requirement. This results in the model identifying the next lowest-cost compliance option specific to that jurisdiction. The resulting portfolio would go through the same integration process described above.

Washington Portfolios

As discussed above – the integrated preferred portfolio reflects is optimized to meet Washington customer energy and capacity needs, and the Washington Clean Energy Transformation Act (CETA) clean energy standards from 2030 onwards. The final integrated portfolio presents a CETA-compliant path towards a greenhouse gas neutral, and ultimately zero-emitting, supply of electricity for Washington customers, as described in further detail in Appendix O, Clean Energy Action Plan (CEAP). This CETA-compliant portfolio, as described in the CEAP, serves as a draft portfolio that will be the basis for the forthcoming 2025 Clean Energy Implementation Plan (CEIP) expected to be filed with the Washington Commission in October 2025.

The focus of this draft IRP filing is to present, at a minimum, a draft of an integrated preferred portfolio that meets all state-specific requirements. As described in this chapter and further in Appendix O, Clean Energy Action Plan, the draft IRP preferred portfolio presents a strategy to get to a portfolio that is optimized to meet Washington CETA clean energy standards over the next twenty years. Additional scenarios and sensitivities as required by Washington rule, will be included in the final IRP filing.

Per WAC 480-100-620(10): the IRP must also include a range of possible future scenarios and input sensitivities. These include:

- **Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards. This case is comparable to the initial SCGHG price-policy scenario study, but includes Washington-specific capacity requirements based on WRAP. This sensitivity includes the requirement to use the social cost of greenhouse gases (SC) price-policy assumption in resource acquisition decisions. In Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA compliant outcomes.

- **Climate Change** - WAC 480-100-620(10)(b) instructs utilities to “incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change.” Please see Appendix A for additional detail regarding how climate change is incorporated into the base load forecast. Climate change impacts are also incorporated in the base hydro forecast. Because the base forecast includes climate change, all of the IRP analysis reflects impacts related to climate change, so a separate sensitivity to include these impacts is not necessary.

- **Maximum Customer Benefit -** WAC 480-100-620(10)(c) instructs utilities to “model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals.” The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp’s Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and includes all available Washington energy efficiency and demand response. The study also removes Yakima and Walla Walla area transmission options and relies on increased small-scale renewables.

Each of these studies is most pertinent to the State of Washington and are further discussed in Chapter 9 (Modeling and Portfolio Selection Results).

Sensitivity Case Definitions

Note – Sensitivity cases, which are not eligible for selection as the preferred portfolio, are under development and will be evaluated and included in the March 31, 2025 filing of the 2025 IRP. The list of planned sensitivities is described below.

PacifiCorp identified ten sensitivities outlined in Table 8.7 and discussed further in Volume I, Chapter 9.

Table 8.7 – Sensitivity Case Definitions

Sensitivity	Definition
High Load Growth	Base load forecast replaced by a high load version
Low Load Growth	Base load forecast replaced by a low load version
1-20 Peak Load	Base load forecast replaced by a high load version using historical 20 year highest load
High Private Generation	Assumes lower load due to high private generation adoption
Low Private Generation	Assumes higher load due to low private generation adoption
Large Metered Load Growth	Assumes significant large metered customer load growth
Low Cost Renewables	Assumes high adoption of IRA/IIJA benefits leads to large cost declines
Low PTC/ITC eligibility	Assumes changes to IRA/IIJA leading to shorter PTC/ITC eligibility window
All CCUS	Allows CCUS to be selected at any coal site
Jim Bridger Long Term Fuel	Adjusts the long term fuel plan at Jim Bridger to assess impacts of change
B2H Delayed to 2030	In the Large Metered Load Growth scenario, B2H is not eligible until 2030
Business as Usual	Portfolio if no state requirements existed
Business Plan	First 3 years are aligned with the current business plan

High Load Growth
In this sensitivity the base load forecast is replaced with a high load forecast. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of higher loads.

Low Load Growth
In this sensitivity the base load forecast is replaced with a low load forecast. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of lower loads.

1 in 20 Peak Load
In this sensitivity the base load forecast is replaced with a high load forecast based on a historical 20-year high load year. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of the 20-year high load year.

High Private Generation
In this sensitivity the base load forecast is replaced with a new load forecast incorporating high private generation which reduces load. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of a future with high private generation.

Low Private Generation
In this sensitivity the base load forecast is replaced with a new load forecast incorporating low private generation which increases load. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of a future with low private generation.

Large-Metered Load Growth - All State Compliant
In this sensitivity the base load forecast is replaced with a new load forecast incorporating high large-metered load growth. The preferred portfolio is re-optimized with this new load forecast to evaluate the cost and risk impacts of future high large-metered load growth. This portfolio has

gone through the same integration process to fill any state compliance shortfalls as the preferred portfolio.

Force Small Scale Resources

In this sensitivity small-scale resources are forced into the preferred portfolio in place of utility scale resources. While the number of small-scale resources is forced into the portfolio, the type, timing, and location of these small-scale resources is selected endogenously. The portfolio is re-optimized to evaluate the cost and risk impacts of small-scale resources.

No Small-Scale Resources

In this sensitivity small-scale resources are removed from the preferred portfolio and replaced with utility scale resources. The amount of utility scale resources forced into the portfolio is the same as the amount of small scale removed, but the type, timing and location of these utility scale resources is selected endogenously. The portfolio is re-optimized to evaluate the cost and risk impacts of replacing small scale resources with utility scale resources.

Low Cost Renewables

This sensitivity assumes high IRA/IIJA adoption results in significant cost reductions for PTC/ITC eligible resources. which replace non-PTC/ITC eligible resources. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this sensitivity is to show how greater than anticipated IRA/IIJA eligible resource availability might impact cost and risk.

Low PTC and ITC Eligibility

This sensitivity assumes IRA/IIJA changes result in PTC and ITC eligibility ending in 2030. Resources coming online after 2030 do not have the cost reductions associated with PTC and ITC. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this sensitivity is to show how lower than anticipated IRA/IIJA eligible resource availability might impact cost and risk.

All CCUS

This sensitivity allows all CCUS to be selected at appropriate coal sites, assuming that it is feasible to complete installation across the entirety of the eligible majority-owned coal fleet prior to 2032. The portfolio is fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if CCUS is a commercially viable option at more than one coal site before 2032.

Jim Bridger Long Term Fuel Plan Adjustment

This sensitivity uses a different long term fuel plan for the Jim Bridger plant compared to the base assumption. The purpose of this variant is to show how a different long term fuel plan for Jim Bridger impacts costs and risks in the preferred portfolio while maintaining reliability.

B2H Delayed 2030

In this sensitivity, where B2H may be economic to support significant growth in large-metered load, the transmission segments associated with the Boardman-to-Hemingway project are delayed from 2027 until 2030. All incremental lines dependent on these lines are also delayed three years. The portfolio is then re-optimized to determine a portfolio necessary to maintain reliability. The purpose of this sensitivity is to evaluate the cost and risk impacts associated with the Boardman-to-Hemingway line becoming available to support growth in large-metered load later than anticipated.

Business As Usual[20] (No Pending Legislation or State Requirements; Locked Coal Assumptions)

In this sensitivity, all pending legislation and state requirements are removed so that the only obligations to be met are load and federal policy obligations. Coal outcomes are also locked to assumptions in the 2017 IRP Update except to the extent that updated commitments or requirements supersede the older assumptions. The portfolio is otherwise fully endogenous and has gone through the same level of integration as the preferred portfolio. The purpose of this variant is to evaluate how the preferred portfolio would change if no potential state requirements or early economic retirements were considered.

Business Plan Sensitivity

In the 2025 IRP, this case is aligned with the integrated preferred portfolio due to the base assumptions being aligned. For this reason, no additional sensitivity is needed. The case complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with those identified in the preferred portfolio. All other resource selections are optimized using the Plexos models.

[20] Per the Wyoming Public Service Commission's (WPSC) 2019 Investigation Order (DOCKET NO. 90000-144-XI-19, and DOCKET NO. 90000-147-XI-19), "reference case" is the formal terminology for the business-as-usual study. Regarding this study, the WPSC mandates the following:

> "In the anticipated 2021 IRP, and in IRPs and updates thereto filed by the Company thereafter, Rocky Mountain Power shall:
> a) Include a Reference Case based on the 2017 IRP Updated Preferred Portfolio, incorporating updated assumptions, such as load and market prices and any known changes to system resources and only incorporate environmental investments or costs required by current law"

This case was the subject of stakeholder feedback and discussion in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #35 (Wyoming Energy Authority).

CHAPTER 9 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly.
- PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process. The preferred portfolio continues to include continued operation of most of its existing fleet, plus substantial new renewables, facilitated by incremental transmission investments, along with demand-side management (DSM) resources, storage resources, and advanced nuclear.
- The 2025 IRP preferred portfolio includes resources which have been contracted since the 2023 IRP, including 520 megawatts (MW) of new storage resources. The 2025 IRP preferred portfolio includes near-term proxy resource selections that align with recent transmission cluster studies, and it is expected that a forthcoming RFP as outlined in the action plan will soon be soliciting and evaluating resources to fulfill these needs.
- The 2025 IRP preferred portfolio also includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Over the planning horizon, the 2025 IRP preferred portfolio includes 6,379 MW of new wind, 2,308 MW of which is small-scale, and 5,492 MW of new solar.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the portfolio includes multiple upgrades increasing connection from Utah South into the Wasatch Front area, a new 230 kV line from the Willamette Valley to Central Oregon, and Gateway South 2, a new 500 kV line from the Aeolus substation in Wyoming to the Clover substation in Utah.
- Driven in part by the need for low-cost firm capacity, existing coal-fired facilities generally continue to operate through the end of the planning period. Majority-owned coal units which are required to cease coal-fired operation are converted to natural gas where the option is available.
- In the 2025 IRP, four factors drive a reduction in CO_2 emissions after 2025. These factors are: retirements (minority-owned units and Dave Johnston 3), additional natural gas conversions (Naughton 1 and 2 and Dave Johnston 1 and 2), reduced capacity factors at existing coal and natural gas facilities, and installation of carbon capture and sequestration (CCS) technology (Jim Bridger 3 and 4). In combination these factors result in 2030 emissions that are less than half of the 2025 level. After 2030, changes in capacity factors are the primary driver, with capacity factors falling initially as a result of renewable resource additions, but rising back to the 2030 level by the end of the horizon in response to growing loads and the expiration of existing contracted resources.

Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the PLEXOS modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp's preferred portfolio selection process and presents the 2025 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio, cost and risk analysis for the variant portfolios, including selection of the preferred portfolio. The final preferred portfolio selection is informed by all relevant modeling results. This chapter also presents modeling results for additional scenarios supporting Washington's Clean Energy Transformation Act (CETA)[1] and discussion of Oregon's compliance position in the preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp's portfolio evaluation processes. Stochastic modeling results are also summarized in Volume II, Appendix J (Stochastic Simulation Results).

Initial Portfolio Development

As discussed in Volume 1, Chapter 8 the portfolio development process in the 2025 IRP is an iterative process where each case, both by jurisdiction and variant, is looped through multiple phases of LT and ST modeling, leveraging results from a prior phase to inform the next phase. Once sufficient phases are complete, an initial study with high reliability and low costs over the study horizon is selected from each jurisdiction's results for integration. Table 9.1 below shows the various phases of the Utah, Idaho, Wyoming and California (UIWC) MN fully initial jurisdictional run to demonstrate a snapshot of how iterative jurisdictional portfolios were evaluated and selected for integration. Given the initial views of these runs, and subsequent integrating, the present-value revenue requirement (PVRR) and unserved energy stream over 21 years were the key factors determining which phase is selected for integration. In Table 9.1, phase 5 was selected as the UIWC initial portfolio for inclusion in the MN integrated portfolio. This selection takes into consideration the PVRR of $21,842 million, and the stream of unserved energy costs that led to a total cost of $1 million which had no unserved energy after 2027. No other phase had both a lower PVRR and a lower unserved energy cost. Other phases which were considered were phase 1, phase 3 and phase 9, however the higher PVRR of phases 3 and 9, and the fact that phase 1 had small amounts of unserved energy through the 21-year study horizon led to phase 5 being selected.

[1] Volume II, Appendix O provides additional detail relevant to Washington requirements.

Table 9.1 – Iterative phases of Utah, Idaho, Wyoming and California MN portfolio

Phase	Jurisdiction	Price-Policy	21 Year PVRR	Unserved Energy Cost
0	UIWC	Medium Gas, No CO2	20,628	14
1	UIWC	Medium Gas, No CO2	21,587	1
2	UIWC	Medium Gas, No CO2	21,212	10
3	UIWC	Medium Gas, No CO2	21,848	1
4	UIWC	Medium Gas, No CO2	22,036	22
5	UIWC	Medium Gas, No CO2	21,842	1
6	UIWC	Medium Gas, No CO2	20,942	29
7	UIWC	Medium Gas, No CO2	21,999	1
8	UIWC	Medium Gas, No CO2	21,128	30
9	UIWC	Medium Gas, No CO2	21,932	1
10	UIWC	Medium Gas, No CO2	21,145	25
11	UIWC	Medium Gas, No CO2	22,143	1
12	UIWC	Medium Gas, No CO2	21,157	19
13	UIWC	Medium Gas, No CO2	22,216	1
14	UIWC	Medium Gas, No CO2	20,526	18
15	UIWC	Medium Gas, No CO2	22,503	3

The fully integrated portfolios and variants differ based on retirement timing, the impact of federal CO_2 policy, requested or required resource availability variations, and options for gas conversion or CCS retrofit for certain units. The portfolios also differ based on natural gas and proxy CO_2 policy assumptions, resulting in uniquely optimized combinations of resources, transmission and thermal retirement options.

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), each variant portfolio went through the iterative process.

Final selection of the top-performing portfolio and preferred portfolio selection also include an assessment of compliance with CETA and Oregon's HB 2021.

Jurisdictional Portfolios

Table 9.2 through Table 9.4 present each jurisdiction's *share* of total portfolio resources as developed from the initial portfolios, prior to integration. For more information about how jurisdictional portfolios are determined, refer to Chapter 8.

Jurisdictional Shares Prior to Integration

Table 9.2 – Oregon Initial Share

OR Shares by Resource Type and Year, Installed MW																						
	Installed Capacity (MW)																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Expansion Options																						
DSM - Energy Efficiency	-	55	79	81	84	87	93	94	94	93	93	83	89	89	87	90	91	101	169	160	151	1,966
DSM - Demand Response	-	24	7	38	6	60	7	4	2	3	1	-	53	51	3	21	30	3	3	37	7	361
Nuclear	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable - Utility Wind	-	-	-	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	83
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	0	-	-	246	4	37	5	-	-	-	-	-	-	1,267
Renewable - Utility Solar	-	-	109	165	-	848	102	579	45	4	-	1,888	1	-	-	-	-	-	-	-	-	3,741
Renewable - Battery	-	132	940	7	-	10	-	2	3	1	1	-	-	2	2	3	7	234	1	1	1	1,346
Renewable - Battery (Long Duration)	-	-	1	26	62	590	166	11	93	44	17	-	-	35	53	100	140	-	198	139	44	1,720

Table 9.3 – Washington Initial Share

WA Shares by Resource Type and Year, Installed MW																						
	Installed Capacity (MW)																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Expansion Options																						
DSM - Energy Efficiency	-	14	13	14	15	15	16	16	16	15	15	13	12	10	9	8	7	7	7	6	4	233
DSM - Demand Response	-	15	4	8	1	-	6	1	-	1	0	-	0	11	1	12	1	1	1	3	1	67
Nuclear	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32
Renewable - Utility Wind	-	-	-	-	594	-	-	0	-	-	3	1,988	-	-	-	-	-	-	-	-	-	2,585
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	5
Renewable - Utility Solar	-	-	136	17	-	-	794	0	4	0	-	-	-	-	-	-	237	-	-	-	-	1,189
Renewable - Battery	-	37	354	6	-	-	-	400	-	93	173	-	-	247	4	78	95	58	192	274	9	2,020
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	11	-	-	4	-	-	7	8	12	5	-	31	6	-	83

Table 9.4 – Utah, Idaho, Wyoming and California Initial Share

UIWC Shares by Resource Type and Year, Installed MW																						
	Installed Capacity (MW)																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Expansion Options																						
DSM - Energy Efficiency	50	57	145	167	172	182	233	219	197	174	157	159	149	134	123	109	102	123	107	103	84	2,947
DSM - Demand Response	14	1	1	98	26	21	-	31	-	42	23	12	13	13	38	18	16	30	68	22	135	622
Nuclear	-	-	-	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Renewable - Utility Wind	-	-	-	403	211	-	-	451	-	-	-	338	-	-	-	-	-	-	-	-	-	1,403
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	236	802	-	-	1,039
Renewable - Utility Solar	-	-	-	-	-	-	-	226	-	0	-	333	3	-	-	-	-	-	-	-	-	563
Renewable - Battery	-	352	2	103	-	30	-	14	-	224	2	-	11	4	4	-	4	197	63	4	4	1,018
Renewable - Battery (Long Duration)	-	-	-	-	-	65	-	-	-	44	46	-	-	285	405	200	180	-	35	187	35	1,481

Full Jurisdictional Portfolios

The following portfolios shown in Table 9.5 through Table 9.7 report the entirety of portfolio selections made when planning for the entire system, not just the jurisdictional share, according to each jurisdiction's constraints.

Table 9.5 – Oregon Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	233	253	261	275	325	322	302	277	260	248	250	233	219	208	201	232	283	269	235	5,064
DSM - Demand Response	18	25	7	38	86	60	7	4	2	3	1	-	255	85	47	46	46	27	79	61	43	940
Renewable - Wind	-	-	222	166	-	594	-	-	-	-	3	-	31	256	-	-	-	-	-	-	-	1,272
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	-	-	1,270
Renewable - Utility Solar	-	-	109	165	-	848	102	807	45	4	2	2,221	4	-	-	-	-	-	-	-	-	4,307
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,091	10	-	19	5	3	25	3	4	-	-	146	6	7	16	504	67	6	6	2,438
Renewable - Battery (Long Duration)	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80	3,285
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**487**	**1,663**	**403**	**666**	**3,035**	**400**	**1,243**	**467**	**372**	**337**	**2,715**	**444**	**855**	**455**	**895**	**246**	**860**	**659**	**435**	**344**	

Table 9.6 – Washington Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Gas - CCCT	-	-	-	-	221	-	-	-	-	-	-	-	-	-	-	-	179	-	-	-	-	400
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	214	236	243	252	326	322	300	283	265	258	260	243	229	217	210	230	285	271	236	5,058
DSM - Demand Response	18	17	4	8	37	-	185	35	-	54	57	-	26	44	42	52	24	45	30	78	40	796
Renewable - Wind	-	-	1,008	-	594	-	-	17	-	-	3	1,990	130	-	-	-	-	-	-	-	-	3,742
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	121	157	-	-	-	194	660	1,132
Renewable - Utility Solar	-	-	136	17	-	-	794	630	4	1	-	-	-	406	-	-	237	-	-	-	-	2,225
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	490	6	-	-	5	747	-	296	196	-	-	269	28	471	177	152	347	285	15	4,004
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	25	-	-	132	-	-	121	139	224	92	395	107	108	-	1,343
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(1,030)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,592)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
Coal - Gas Conversions	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	892
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**479**	**1,852**	**12**	**972**	**331**	**1,101**	**1,776**	**304**	**631**	**653**	**2,248**	**316**	**1,051**	**559**	**1,121**	**521**	**822**	**722**	**703**	**931**	

Table 9.7 – Utah, Idaho, Wyoming, California (UIWC) Full Jurisdictional Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	203	247	256	271	331	319	298	273	255	259	250	233	220	208	207	232	283	271	239	5,033
DSM - Demand Response	18	1	-	157	40	33	-	46	-	86	29	27	17	17	47	47	46	33	74	61	144	923
Renewable - Wind	-	-	-	486	211	-	-	1,045	-	-	-	340	-	-	-	-	-	-	-	-	-	2,082
Renewable - Small Scale Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	143	390	802	-	-	1,335
Renewable - Utility Solar	-	-	-	-	-	-	-	1,675	-	4	-	670	4	-	-	-	-	-	-	-	-	2,353
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	4	444	355	134	-	389	-	232	4	-	11	6	6	-	14	462	65	6	6	2,658
Renewable - Battery (Long Duration)	-	-	-	-	-	130	-	-	-	100	78	368	383	359	466	312	325	-	51	332	70	2,974
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	526
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	-	(50)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**463**	**207**	**1,079**	**739**	**647**	**122**	**3,474**	**298**	**692**	**366**	**1,664**	**565**	**583**	**739**	**567**	**337**	**1,117**	**1,228**	**437**	**439**	

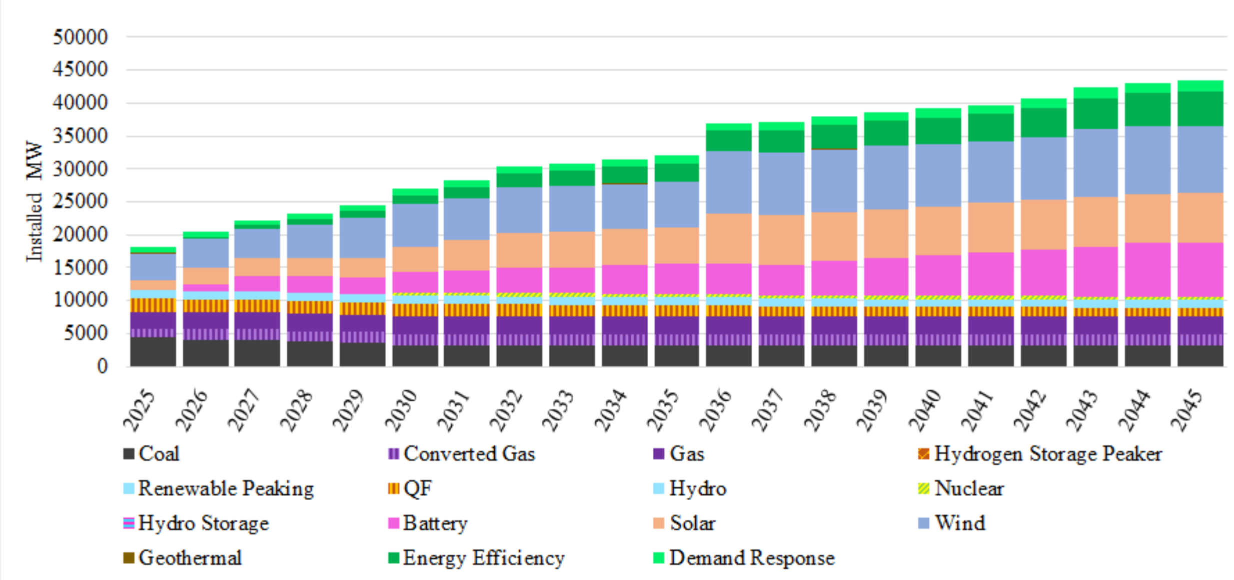
The 2025 IRP Preferred Portfolio

PacifiCorp's selection of the 2025 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 9.1 shows that PacifiCorp's 2025 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, and advanced nuclear.

The 2025 IRP preferred portfolio is in addition to previously contracted resources, some of which have not yet achieved commercial operation, including: 1,564 MW of wind, 1,736 MW of solar additions, and 1,072 MW of battery storage capacity. These resources will come online in the 2024 to 2026 timeframe.

The 2025 IRP preferred portfolio includes the advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. By the end of 2032, the preferred portfolio includes 2,801 MW of energy storage resources, including 844 MW of iron-air batteries with one-hundred-hour storage capability. Advancement of these technologies will be critical to meeting growing loads and achieving environmental compliance requirements. Over the 21-year planning horizon, the 2025 IRP preferred portfolio includes 6,379 MW of new wind and 5,492 MW of new solar.

Figure 9.1 – 2025 IRP Preferred Portfolio (All Resources)



New since the 2023 IRP, the 2025 IRP preferred portfolio includes a second 416-mile transmission line, known as Energy Gateway South 2, running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. This line is scheduled to be operational by 2036. Additionally, smaller upgrades will enhance transfer capability between southern Utah and the Wasatch Front, between Walla Walla and Yakima in Washington, and between the Willamette Valley and Deschutes County in Oregon.

Many of the transmission upgrades and interconnection options modeled for the 2025 IRP reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. Since 2020, PacifiCorp has been evaluating all newly proposed resource additions in an area at the same time, using a cluster study process that identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. Table 9.8 summarizes the incremental transmission projects in the 2025 IRP preferred portfolio.

Table 9.8 – Transmission Projects Included in the 2025 IRP Preferred Portfolio [1,2]

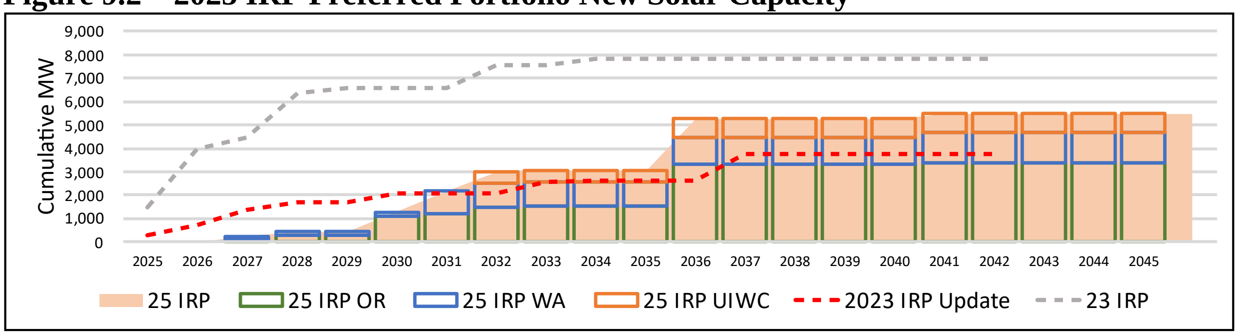
		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2026	Rebuild existing Cameron - Sigurd 138 kV	250	250	250	30	100%	Utah South	Wasatch Front
2027	Cluster 1 Area 11 - Willamette Valley	0	0	199	13	100%	n/a	n/a
	Serial queue - Central Oregon	0	0	152	3	100%	n/a	n/a
2028	Cluster 2 Area 23 - Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Cluster 1/2/3 - Walla Walla	0	0	628	66	100%	n/a	n/a
2031	Cluster 1/2/3 - Walla Walla	0	0	393	348	100%	n/a	n/a
	Walla Walla - Wine Country 230 kV	400	400	400	145	100%	n/a	n/a
2032	Cluster 1 Area 14 - Summer Lake	400	400	400	120	100%	Summer Lake	Hemingway
	Cluster 2/3 - Willamette Valley - Fry-Full Circle 230 kV	450	450	450	413	100%	Willamette Valley	Central OR
2036	Gateway South 2: Aeolus Clover #2 500 kV	1,500	1,500	1,990	1,810	100%	Wyoming East	Clover
	Huntington – Clover 345 kV	800	800	800	264	100%	Utah South	Wasatch Front
	Spanish Fork - Mercer 345 kV	300	300	300	153	100%	Utah South	Wasatch Front
	West Cedar - Three Peaks 138 kV	200	200	200	14	100%	Utah South	Wasatch Front
	S. Lebanon-Dixonville 500 kV, Dbl-Ckt Fry-S.Lebanon 230 kV	1,500	1,500	665	1,117	100%	Willamette Valley	Southern OR
2041	Serial through Cluster 1 Area 13 - Southern Oregon	0	0	231	52	100%	n/a	n/a
Grand Total		**5,800**	**5,800**	**7,451**	**4,551**			

[1] Export and import values represent total transfer capability (TTC). The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
[2] Transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for project-specific timing and some costs are project-specific.

New Solar Resources

The 2025 IRP draft preferred portfolio includes 245 MW of new solar by the end of 2027, 1,275 MW by the end of 2030, and more than 5,492 MW by the end of 2045, as shown in Figure 9.2.

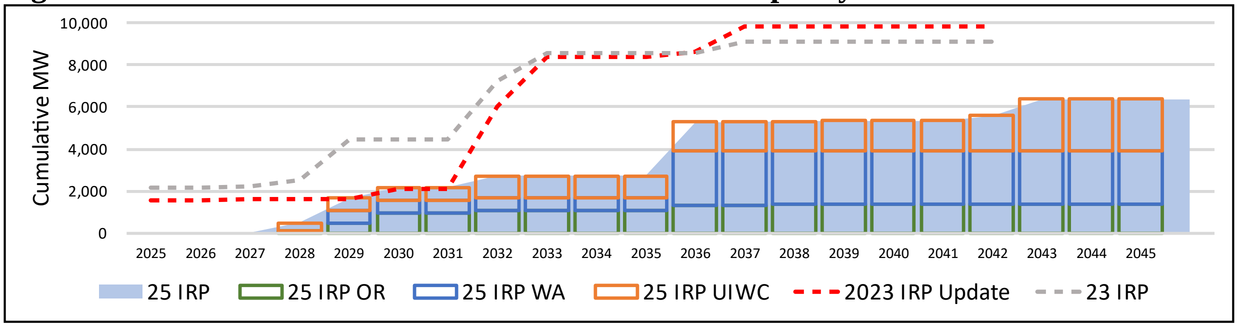
Figure 9.2 – 2025 IRP Preferred Portfolio New Solar Capacity



New Wind Resources

As shown in Figure 9.3, PacifiCorp's 2025 IRP draft preferred portfolio includes 486 MW of new wind generation by the end of 2028, 2,175 MW by the end of 2030, and 6,379 MW of cumulative new wind by the end of 2045.

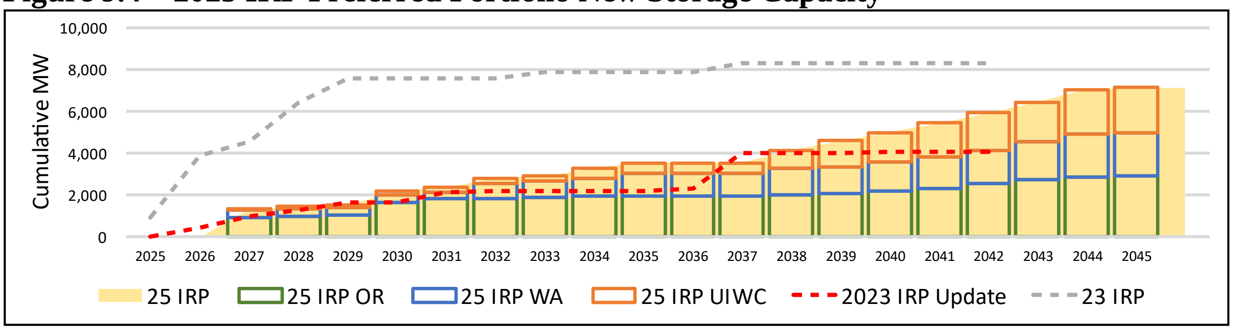
Figure 9.3 – 2025 IRP Preferred Portfolio New Wind Capacity



New Storage Resources

New storage resources in the 2025 IRP draft preferred portfolio are summarized in Figure 9.4. The 2025 IRP draft preferred portfolio includes 1,818 MW of new storage resources by the end of 2027[2] including both 4 and 8-hour lithium-ion storage. By year-end 2030, the 2025 draft IRP includes 2,716 MW of storage which includes nearly 656 MW of 100-hour iron air storage, and by year-end 2045, the 2025 IRP draft preferred portfolio includes 7,668 MW of new storage.

Figure 9.4 – 2025 IRP Preferred Portfolio New Storage Capacity[1]

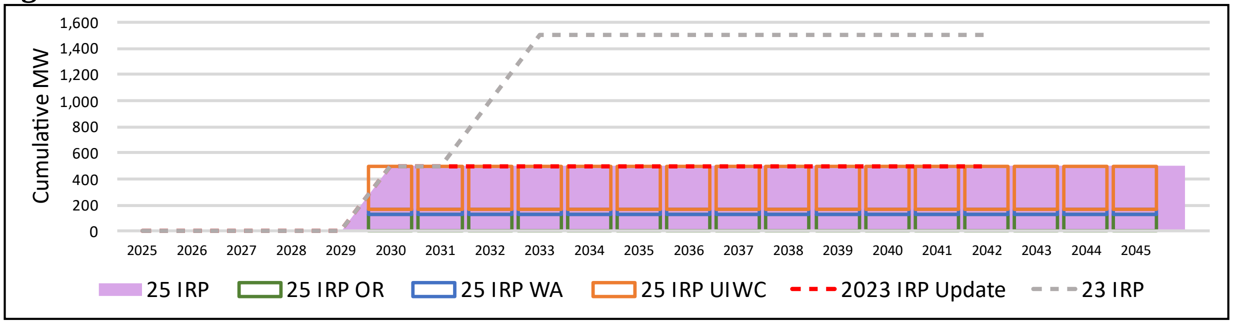


[1] The 2023 IRP Update includes 400 MW of PVS battery (Green River solar+storage) in 2026 that has since been signed and is not included as new storage capacity in the 2025 IRP.
[2] The 1,818 MW of new storage resources by the end of 2027 includes 520 MW of signed battery storage contracts that have been committed since the filing of the 2023 IRP Update.

New Nuclear Resources

The 2025 IRP draft includes new advanced nuclear as part of its least-cost, least-risk preferred portfolio. As shown in Figure 9.5, the 500 MW advanced nuclear Natrium™ demonstration project is currently scheduled to come online by summer 2030.

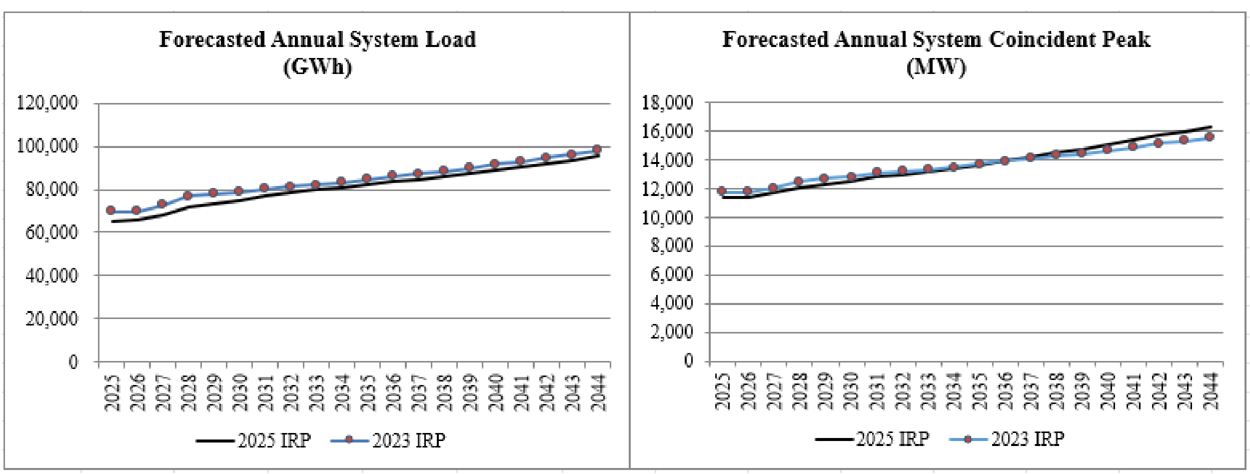
Figure 9.5 – 2025 IRP New Nuclear



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 therefore results in the selection of 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. Figure 9.6 shows that PacifiCorp's load forecast before incremental energy efficiency savings has decreased relative to projected loads used in the 2023 IRP. On average, forecasted system load is down 3.9 percent and forecasted coincident system peak is down 0.6 percent when compared to the 2023 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.03 percent for load and 1.91 percent for peak. Changes to PacifiCorp's load forecast are driven by lower projected demand from new large customers who are expected to bring their own resources lowering the commercial forecast.

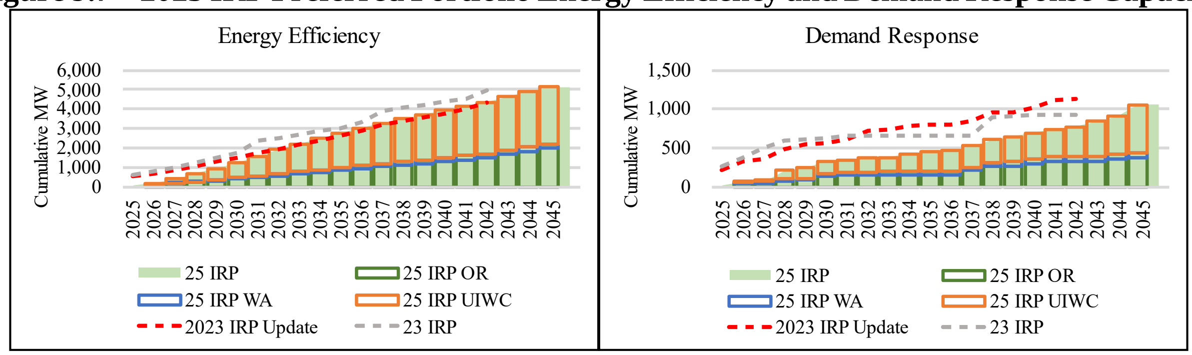
Figure 9.6 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 9.7 compares total energy efficiency capacity savings in the 2025 IRP preferred portfolio relative to the 2023 IRP preferred portfolio and includes 5,149MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 9.7 compares cumulative demand response program capacity in the 2025 IRP draft preferred portfolio relative to the 2023 IRP Update preferred portfolio and does not include capacity from existing programs. The 2025 draft IRP has a cumulative capacity of demand response programs reaching 695 MW by 2040. By year-end 2045, the 2025 IRP draft preferred portfolio has a cumulative capacity of demand response programs reaching 1,052 MW, a 6.3% decrease from the cumulative capacity of demand response programs by the end of the planning horizon in the 2023 IRP Update (1,123 MW).

Figure 9.7 – 2025 IRP Preferred Portfolio Energy Efficiency and Demand Response Capacity

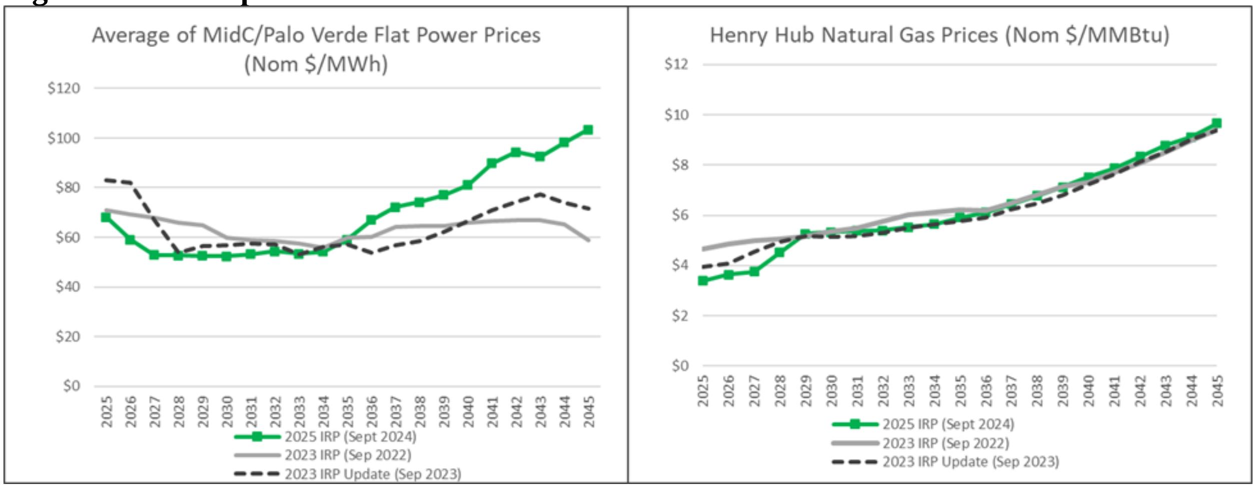


[1] Energy efficiency and demand response in the 2023 IRP Update began escalating two years prior to when escalation begins in the 2025 draft IRP preferred portfolio. Cumulative energy efficiency and demand response in 2045 in the 2025 draft IRP preferred portfolio is similar to cumulative energy efficiency and demand response by 2042 in the 2023 IRP Update, the end of the planning horizon.

Wholesale Power Market Prices and Purchases

Figure 9.8 illustrates that the 2025 IRP's base case forecast for natural gas prices has increased along with an increase in wholesale power prices for most years past 2030 relative to those in the 2023 IRP Update. Prior to 2030, Figure 9.8 reports that the 2025 IRP's base forecast for natural gas and wholesale power prices are lower than those in the 2023 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

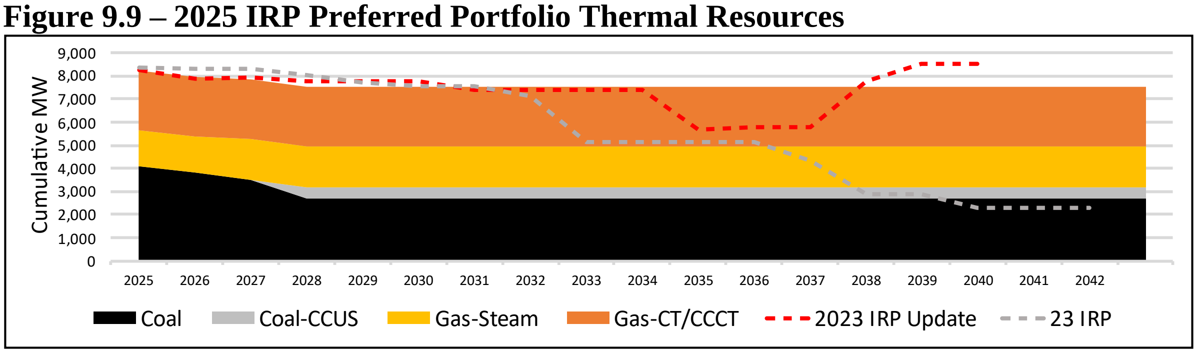
Figure 9.8 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs



Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy. New for the 2025 IRP, coal-fired units that do not have an enforceable environmental compliance requirement have the option to continue coal-fired operation through the end of the study horizon. Where natural gas supply is expected to be reasonably available, an option to convert to natural gas was modeled, and is required for continued operations at units that are required to cease coal-fired operation. As shown in Figure 9.9, the 2025 IRP converts 562 MW of coal fueled generation to natural gas fueled, and exits PacifiCorp's share in 386.2 MW of minority-owned coal, and an additional 220 MW of majority-owned coal by the end of the study horizon. The balance of the coal units continue to operate through the end of the study horizon, with 700 MW at Jim Bridger 3 and 4 converting to carbon capture in 2030.

Figure 9.9 – 2025 IRP Preferred Portfolio Thermal Resources



A summary of the coal unit exits, retirements, and conversions in the 2025 IRP preferred portfolio and the 2023 IRP Update preferred portfolio is shown in Table 9.9. In addition to these coal unit exits, retirements, and conversions, the preferred portfolio continues to operate all existing natural gas units through the end of the study horizon.[2]

Table 9.9 – 2025 IRP Coal Resource Results

Majority-Owned Coal		
Unit	2023 IRP Update Retirement Year	2025 IRP Retirement Year
	As Selected	As Selected
Dave Johnston 1 & 2	2028 (Coal ash compliance)	Not retired (Gas conversion 2029)
Dave Johnston 3	2027 (Clean air compliance)	2027 (Clean air compliance)
Dave Johnston 4	2039 (Assumed end of life)	Not retired
Hunter 1-3	2042 (Assumed end of life)	Not retired
Huntington 1 & 2	2036 (Assumed end of life)	Not retired
Jim Bridger 1 & 2	2037 (Gas conversion 2024/Assumed end of life)	Not retired (Gas conversion 2024)
Jim Bridger 3 & 4	2039 (CCS/Assumed end of life)	Not retired (CCS)
Naughton 1 & 2	2036 (Gas conversion 2026/Assumed end of life)	Not retired (Gas conversion 2026)
Wyodak	2039 (Assumed end of life)	Not retired (Coal)
Minority-Owned Coal		
Unit	2023 IRP Update Retirement Year	2025 IRP Retirement Year
	As Input	As Input
Colstrip 3	2025 (Transfer capacity to unit 4)	2025 (Transfer capacity to unit 4)
Colstrip 4	2029 (PacifiCorp exit)	2029 (PacifiCorp exit)
Craig 1	2025 (Assumed end of life)	2025 (Assumed end of life)
Craig 2	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 1	2028 (Assumed end of life)	2028 (Assumed end of life)
Hayden 2	2027 (Assumed end of life)	2027 (Assumed end of life)

Carbon Dioxide Equivalent Emissions

The 2025 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects an overall declining trajectory of carbon dioxide and other carbon dioxide equivalent emissions resulting in a total (CO_2e) emissions decline. PacifiCorp's emissions have been declining and continue to decline because of several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, storage and transmission advancements; and Regional Haze compliance that capitalizes on flexibility.

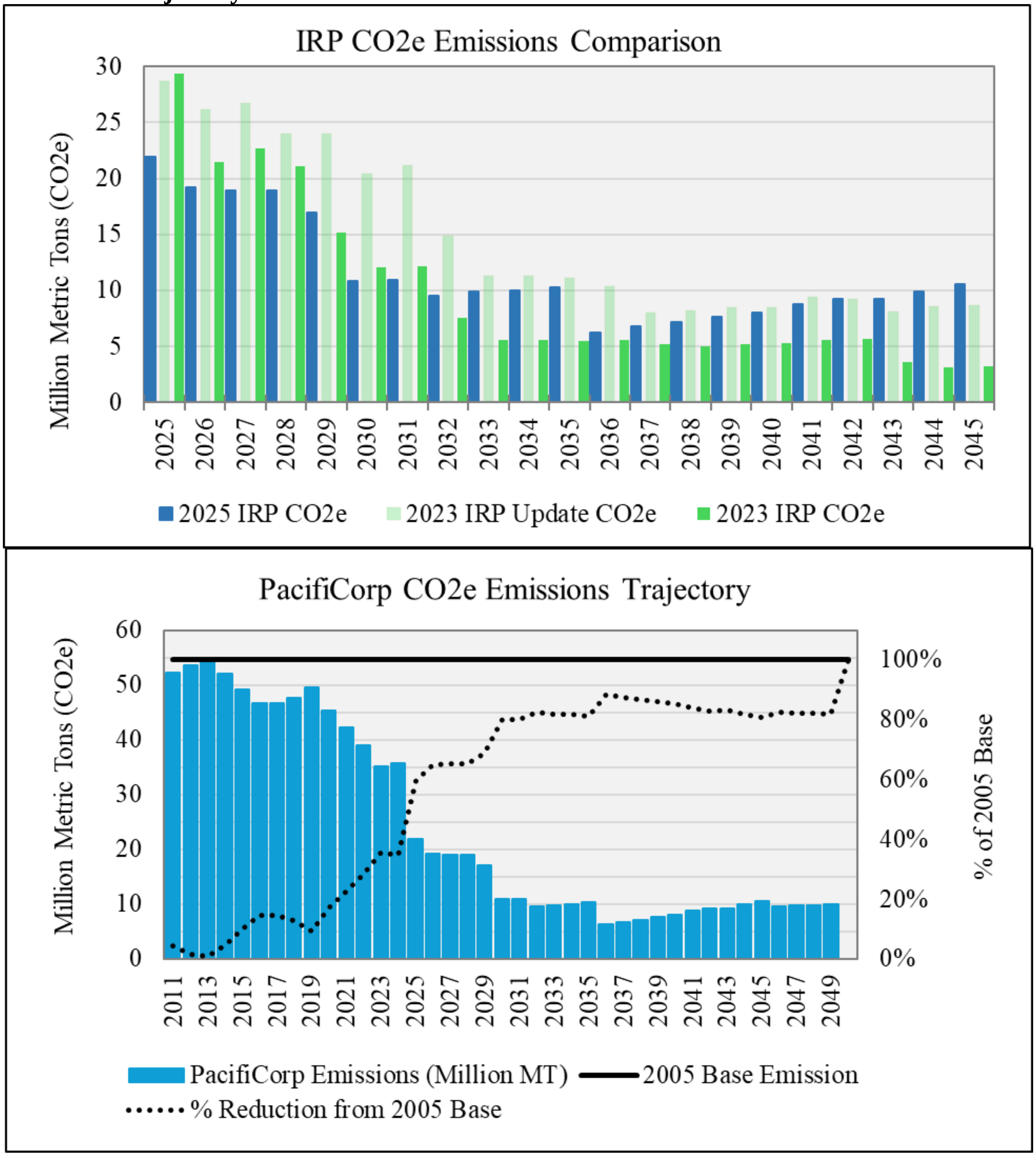
The chart on the left in Figure 9.10 compares projected annual CO_2e emissions across the 2025 IRP, 2023 IRP, and 2023 IRP Update preferred portfolios and is inclusive of emissions attributed to market purchases. The 2025 IRP delivers greater emission reductions between 2025 to 2032 outperforming both the 2023 IRP and 2023 IRP Update, with average annual CO2e emissions down 8% by 2030 relative to the 2023 IRP. After 2032, emissions are forecasted to rise moderately above the 2023 IRP due in part to a higher load forecast in the 2025 IRP and the expiration of

[2] PacifiCorp's Chehalis and Hermiston natural gas units are subject to Washington and Oregon regulation, respectively, and a final determination of state allocations, potential operational restrictions and economics continue to be evaluated.

existing contracted resources. The difference in emissions from the 2023 IRP also reflects the 2025 IRP's balanced strategy to maintaining low-cost firm capacity by allowing existing coal plants to operate through the planning period at a reduced capacity. In addition, some coal plants convert to natural gas or install CCS technology. Through these shifts, the overarching trend points to continued emissions reductions, supporting long-term decarbonization goals. By the end of the planning horizon, system CO2e emissions are projected to fall from 22.0 million metric tons in 2025 to 10.6 million tons in 2045—a reduction of 52 percent.

The chart on the right in Figure 9.10 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that, relative to a 2005 baseline of 54.6 million metric tons, system CO2 equivalent emissions are down 60 percent in 2025, 80 percent in 2030, and 85 percent in 2040.

Figure 9.10 – 2025 IRP Preferred Portfolio CO2 Emissions and PacifiCorp CO2 Equivalent Emissions Trajectory[1]



[1] PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2022 from owned facilities, specified sources and unspecified sources. 2023 emissions have yet to be updated for actuals and 2024 emissions were not forecasted in the 2025 IRP. Therefore both 2023 and 2024 reflect the forecast from the 2023 IRP. From 2025 through the end of the 21-year planning period in 2045, emissions reflect those from the 2025 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2045, emissions reflect the rolling average emissions of each resource from the 2025 IRP preferred portfolio through the life of the resource or the end of the contract. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be discussed in more detail in its Clean Energy Plan.

Renewable Portfolio Standards

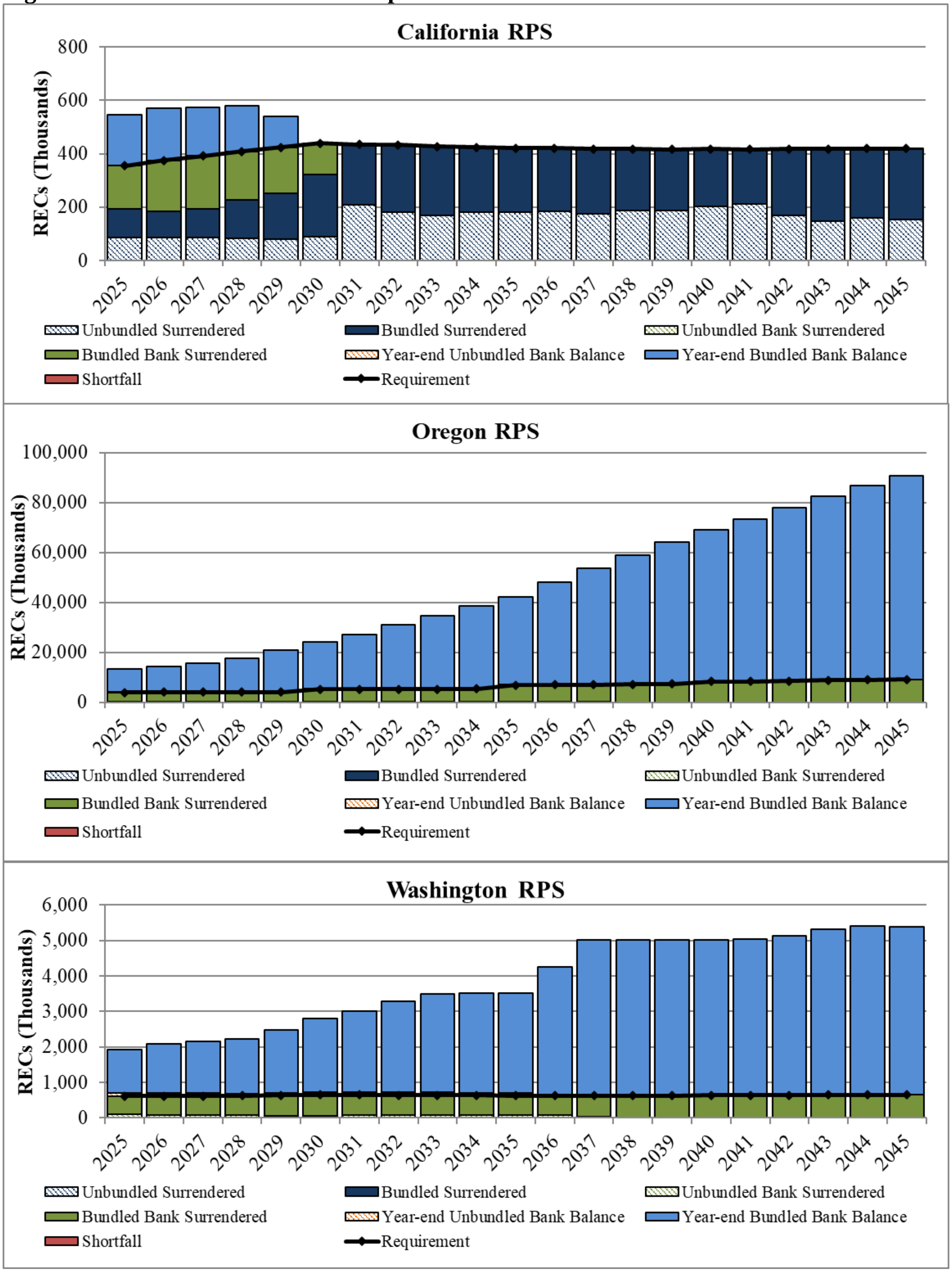
Figure 9.11 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for unbundled REC purchases and new renewable resources in the preferred portfolio. While new resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2045 with the addition of new renewable resources. Washington RPS compliance is also achieved through 2045 with the addition of new renewable resources. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington receives a share of renewable resources across PacifiCorp's system; however, Washington may also benefit from the situs allocation of new renewable resources as necessary for compliance.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as unbundled REC purchases throughout the 2025 IRP study period. The increasing RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in the long term. The company will rely on a combination of new renewable resources from the preferred portfolio and unbundled RECs to meet future shortfalls.

Although not depicted in Figure 9.11, PacifiCorp achieves Utah's 2025 state target of supplying 20 percent of adjusted retail sales with eligible renewable resources through a combination of existing owned and contracted resources, along with new renewable resources and transmission included in the 2025 IRP preferred portfolio.

Figure 9.11 – Annual State RPS Compliance Forecast



Oregon HB2021 Compliance

In 2021, Oregon adopted House Bill 2021, an energy policy seeking to reduce emissions from electric generation facilities used to serve customers in the state. HB 2021 sets targets to reduce emissions associated with Oregon retail sales from a baseline, calculated as the average emissions reported from years 2010 through 2012, by 80 percent in 2030, 90 percent by 2035 and 100 percent by 2040. For PacifiCorp, this requires the company to reduce baseline emissions of 8.99 million metric tons (MMT) of carbon dioxide equivalents (CO_2e) to 1.79 MMT CO_2e by 2030, 0.89 MMT CO_2e by 2035, and zero by 2040. The law also increased Oregon's small-scale renewable energy project purchase requirement from 8 to 10 percent by 2030.

The 2025 IRP preferred portfolio was developed to incorporate resources specifically selected to meet all state-specific requirements, including Oregon's greenhouse gas emission reduction targets defined by HB 2021. PacifiCorp also modeled the small-scale renewable portfolio requirement to ensure that at least 10 percent of Oregon-allocated capacity will be small-scale (20 MW or less), in each year from 2030 onwards.

Greenhouse gas emissions methodology

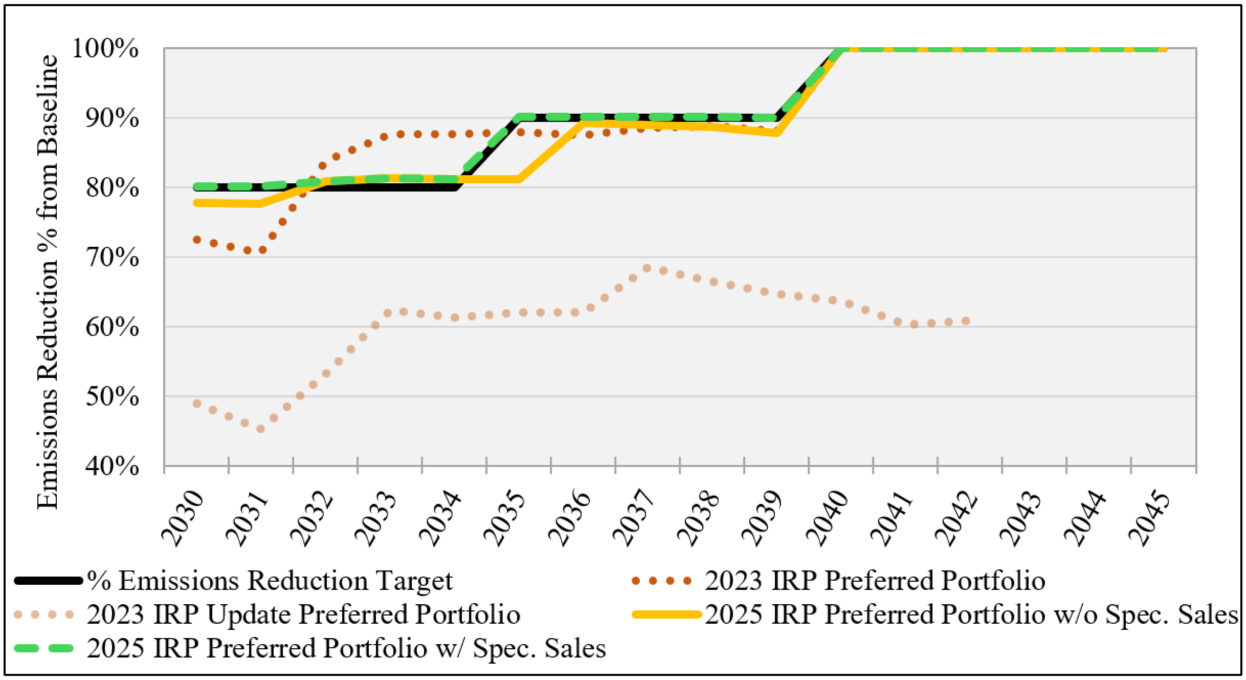
PacifiCorp's greenhouse gas accounting framework for HB 2021 compliance, including emissions forecast and reduction targets, is based on the statute itself and rules and guidance from Oregon Department of Environmental Quality's (ODEQ) longstanding greenhouse gas reporting program.

ODEQ is responsible for verifying utility emissions forecasts to determine compliance with HB 2021's clean energy targets.[3] Consistent with this responsibility, ODEQ developed guidance for projecting and reporting emissions for HB 2021 purposes that leverages methodologies from the agency's Greenhouse Gas Reporting Program rules.[4] This guidance includes proposed emission factors for utilities to use in emissions forecasts for CEPs.[5] The agency has not yet provided PacifiCorp with updated 2025 CEP emission factors, so this draft uses the emission factors developed by ODEQ for the 2023 CEP. In addition to emissions factors, ODEQ provided guidance for multi-jurisdictional utility reporting, adjustments for netting wholesale sales or non-retail electricity, accounting for transmission losses, and accounting for electricity purchased from specified and unspecified sources.[6] Finally, HB 2021 requires PacifiCorp to exclude emissions from net metering of customer resources and qualifying facilities under the terms of the Public Utility Regulatory Policies Act from its determination of compliance with clean energy targets.[7]

[3] ORS § 469A.420; Oregon Department of Environmental Quality, "DEQ's Evaluation of Clean Energy Targets: Overview of DEQ's role in verification and determination of emissions data required by HB 2021" (available at https://www.oregon.gov/deq/ghgp/Documents/CEPBackground.pdf).
[4] OAR 340-215-0010 through -0125; Oregon Department of Environmental Quality, "GHG Emissions Accounting for House Bill 2021 Reporting and projecting emissions from electricity using DEQ methodology" (available at https://www.oregon.gov/deq/ghgp/Documents/HB2021EFGuidance.pdf).
[5] Oregon Department of Environmental Quality, "Greenhouse Gas Emission Factors for HB 2021 Electricity Sector Emission Projections" (available at https://www.oregon.gov/deq/ghgp/Documents/HB2021-EmissionFactors.xlsx).
[6] Oregon Department of Environmental Quality, "Multi-jurisdictional Utilities: Instructions for reporting greenhouse gas emissions" (available at https://www.oregon.gov/deq/aq/Documents/GHGRP-MutlijurisdictionalProtocol.pdf).
[7] PacifiCorp has updated its methodology for calculating progress toward HB2021 targets since the 2023 CEP. In the 2023 CEP, both emissions and generation from QFs were excluded from the progress calculation. However, upon a close review of the regulation, it was determined that the statute only requires the exclusion of emissions associated with QFs. This revised approach has been applied in the 2025 CEP.

Based on emissions factors and methodology framework, the modeling process allows for endogenous selection of proxy resources and optimized dispatch of resources and market transactions to determine a resource portfolio that meets HB 2021 obligations for Oregon customers. The emissions trajectory associated with serving Oregon retail customers is depicted in Figure 9.12. Resources allocated to Oregon customers exceed annual energy requirements, and compliance can be achieved through economic specified-source wholesale sales of a portion of the excess supply, where the purchaser is responsible for the associated emissions.

Figure 9.12 – Oregon Allocated Emission Reduction Relative to HB 2021 Target



Capacity and Energy

Figure 9.13 and Figure 9.14 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[8] On an energy basis, coal generation drops below 20 percent in 2026, falling below 10 percent in 2036, and remaining below 10 percent through the end of the planning period. On a capacity basis, coal resources drop to 12 percent. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources and DSM resources.

[8]The projected PacifiCorp 2021 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2021 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 9.13 – Projected Energy Mix with Preferred Portfolio Resources

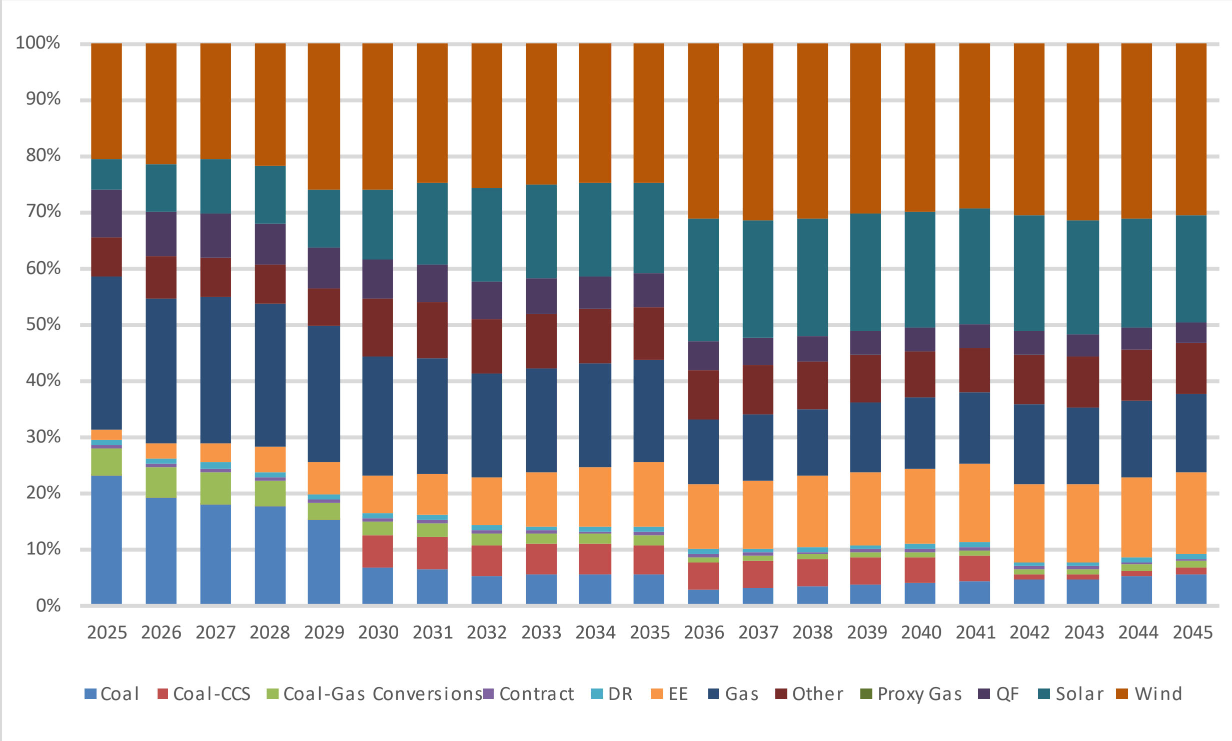
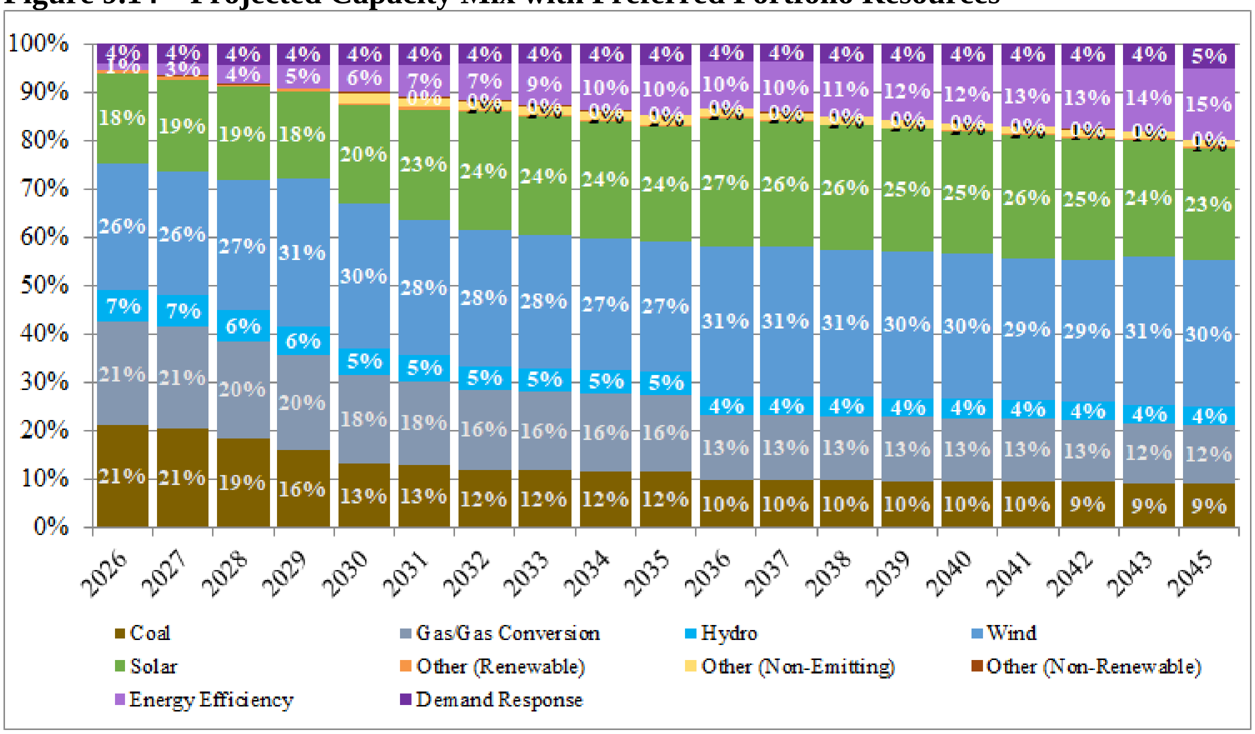


Figure 9.14 – Projected Capacity Mix with Preferred Portfolio Resources



Detailed Preferred Portfolio

Table 9.10 provides line-item detail of PacifiCorp's 2025 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 21-year planning horizon.

Table 9.11 and Table 9.12 report line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 21-year planning horizon.

Table 9.13 and Table 9.14 report line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the 21-year horizon.

Table 9.10 – PacifiCorp's 2025 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																					
Resource	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**Total**
Expansion Options																						
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	89	89	238	262	270	285	342	329	308	282	265	255	250	233	220	208	201	232	283	269	239	5,149
DSM - Demand Response	18	40	11	144	33	81	13	36	2	46	24	12	66	76	42	51	46	33	71	63	144	1,052
Renewable - Wind	-	-	-	486	804	-	-	451	-	-	3	2,327	-	-	-	-	-	-	-	-	-	4,071
Renewable - Small Scale Wind	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	236	802	-	-	2,308
Renewable - Utility Solar	-	-	245	182	-	848	896	805	49	5	-	2,221	4	-	-	-	237	-	-	-	-	5,492
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	520	1,297	116	-	39	-	416	3	317	176	-	11	253	10	81	105	488	257	279	15	4,383
Renewable - Battery (Long Duration)	-	-	1	26	62	655	166	22	93	88	67	-	-	326	466	312	325	-	264	332	80	3,285
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																						
Coal Plant Retirements - Minority Owned	-	(82)	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(386)
Coal Plant Retirements	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(220)
Coal Plant Ceases as Coal	-	(357)	-	-	(205)	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,262)
Coal - CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	562
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	-	-	(3)	-	-	-	(32)	-	-	-	-	-	-	-	(35)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	(64)	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(696)
Expire - Solar PPA	-	-	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(230)	-	(407)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(47)	(3)	(2)	(52)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**107**	**502**	**1,792**	**961**	**1,426**	**1,966**	**1,212**	**2,144**	**455**	**735**	**535**	**5,061**	**235**	**893**	**747**	**652**	**516**	**989**	**1,630**	**710**	**456**	

Table 9.11 – Preferred Portfolio Summer Capacity Load and Resource Balance (2025-2034)

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	3,959	3,567	3,567	3,375	3,090	2,926	2,926	2,926	2,926	2,926
Gas	2,984	3,294	3,294	3,295	3,469	3,470	3,470	3,470	3,470	3,470
Hydroelectric	76	76	76	76	76	76	76	76	76	76
Wind	246	224	218	211	205	189	168	162	157	151
Solar	342	499	488	476	464	453	441	429	418	406
Other Renewable	46	45	44	42	41	40	38	37	36	34
Storage	1	939	925	909	894	879	865	849	834	819
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	413	404	395	386	377	368	359	348	334	323
Demand Response	305	300	295	290	286	281	276	271	266	262
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	0	(639)	(822)	(627)	(335)	(1,131)	(1,021)	(595)	(628)	(494)
East Existing Resources	**8,373**	**8,709**	**8,480**	**8,434**	**8,567**	**7,549**	**7,598**	**7,975**	**7,889**	**7,974**
Additional Proxy/Short-Term Purchases	190	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	2	2	2	2	2	2
Wind	0	0	0	85	185	268	263	273	267	263
Solar	0	0	0	0	0	0	0	0	0	0
Storage	0	0	136	160	220	867	1,029	1,049	1,139	1,224
Nuclear	0	0	0	0	0	300	300	300	300	300
Demand Response	0	0	0	73	92	106	106	127	127	157
East Planned Resources	**190**	**0**	**137**	**319**	**499**	**1,543**	**1,701**	**1,751**	**1,836**	**1,947**
East Total Resources	**8,563**	**8,710**	**8,617**	**8,753**	**9,065**	**9,092**	**9,299**	**9,726**	**9,725**	**9,920**
Load	7,734	7,947	7,952	8,230	8,667	8,855	9,050	9,335	9,335	9,284
Distributed Generation	(157)	(143)	(186)	(234)	(285)	(341)	(400)	(458)	(515)	(354)
Energy Efficiency	(92)	(191)	(234)	(346)	(457)	(566)	(561)	(852)	(880)	(996)
East Total obligation	**7,485**	**7,613**	**7,532**	**7,651**	**7,924**	**7,948**	**8,089**	**8,025**	**7,940**	**7,934**
East Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	15.0%	21.2%	22.5%	25.0%
West										
Coal	140	133	133	133	133	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712
Wind	0	0	0	0	0	0	0	0	0	0
Solar	69	67	65	62	60	58	52	50	48	46
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	2	1	1	1	1	1	1	1	1	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	229	224	212	207	198	194	188	178	174	170
Demand Response	60	59	58	58	57	56	55	55	54	53
Transfers	0	639	822	627	335	1,131	1,021	595	628	494
West Existing Resources	**1,927**	**2,551**	**2,719**	**2,516**	**2,212**	**2,868**	**2,745**	**2,307**	**2,332**	**2,191**
Additional Proxy/Short-Term Purchases	2,145	1,711	568	720	1,079	166	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	64	64	64	112	112	111
Solar	0	0	133	225	218	627	1,031	1,363	1,333	1,285
Storage	0	0	847	920	908	923	912	1,186	1,171	1,369
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	0	6	9	42	44	44	48	49	49	50
West Planned Resources	**2,145**	**1,718**	**1,559**	**1,907**	**2,313**	**1,825**	**2,055**	**2,710**	**2,665**	**2,815**
West Total Resources	**4,072**	**4,269**	**4,278**	**4,423**	**4,525**	**4,693**	**4,799**	**5,017**	**4,998**	**5,006**
Load	3,672	3,826	3,938	4,121	4,271	4,482	4,609	4,828	4,946	4,887
Distributed Generation	(49)	(54)	(75)	(99)	(124)	(152)	(182)	(213)	(244)	(148)
Energy Efficiency	(63)	(41)	(123)	(157)	(191)	(227)	(231)	(229)	(334)	(364)
West Total obligation	**3,560**	**3,731**	**3,740**	**3,866**	**3,955**	**4,102**	**4,195**	**4,386**	**4,368**	**4,376**
West Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%
System										
Total Resources	12,635	12,978	12,895	13,175	13,590	13,785	14,099	14,743	14,723	14,926
Obligation	11,045	11,345	11,272	11,517	11,879	12,050	12,284	12,410	12,308	12,310
Planning Reserves (14.4%)	1,590	1,634	1,623	1,658	1,711	1,735	1,769	1,787	1,772	1,773
Obligation + Reserves	12,635	12,978	12,895	13,175	13,590	13,785	14,053	14,197	14,081	14,082
System Position	0	0	0	0	0	0	45	546	642	844
Reserve Margin	**14.4%**	**14.4%**	**14.4%**	**14.4%**	**14.4%**	**14.4%**	**14.8%**	**18.8%**	**19.6%**	**21.3%**

Table 9.12 – Preferred Portfolio Summer Capacity Load and Resource Balance (2036-2045)

East

	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926	2,926
Gas	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470	3,470
Hydroelectric	76	76	76	76	76	76	76	76	76	76	76
Wind	145	140	134	128	122	117	81	77	73	69	65
Solar	395	383	343	332	322	311	300	290	279	246	236
Other Renewable	33	32	30	11	11	10	9	9	8	8	0
Storage	804	788	773	759	744	728	714	699	684	668	654
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	314	302	240	231	223	211	204	196	189	182	176
Demand Response	257	252	247	243	238	233	228	223	218	214	209
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(469)	(310)	(491)	(366)	(567)	(653)	(663)	(627)	(708)	(607)	(765)
East Existing Resources	**7,950**	**8,060**	**7,749**	**7,811**	**7,564**	**7,430**	**7,346**	**7,339**	**7,216**	**7,252**	**7,047**
Additional Proxy/Short-Term Purcha	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	2	2	3	3	3	3	3	3	3	3	3
Wind	258	641	628	621	609	596	583	601	691	675	658
Solar	0	316	306	297	287	278	268	258	249	239	230
Storage	1,288	1,286	1,284	1,605	2,064	2,371	2,690	2,688	2,947	3,273	3,350
Nuclear	301	301	301	301	301	301	301	301	301	301	302
Demand Response	172	181	189	198	230	241	251	265	294	307	401
East Planned Resources	**2,022**	**2,726**	**2,711**	**3,024**	**3,494**	**3,789**	**4,095**	**4,116**	**4,484**	**4,799**	**4,943**
East Total Resources	**9,972**	**10,786**	**10,460**	**10,835**	**11,058**	**11,219**	**11,441**	**11,454**	**11,700**	**12,051**	**11,990**
Load	9,411	9,557	9,767	9,935	10,083	10,201	10,339	10,480	10,664	10,745	10,883
Distributed Generation	(385)	(415)	(445)	(474)	(503)	(529)	(557)	(584)	(609)	(635)	(660)
Energy Efficiency	(1,110)	(1,151)	(1,024)	(1,333)	(1,462)	(1,515)	(1,580)	(1,315)	(1,562)	(1,583)	(1,613)
East Total obligation	**7,916**	**7,990**	**8,298**	**8,129**	**8,118**	**8,156**	**8,202**	**8,581**	**8,492**	**8,528**	**8,610**
East Reserve Margin	26.0%	35.0%	26.1%	33.3%	36.2%	37.6%	39.5%	33.5%	37.8%	41.3%	39.3%

West

Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric	712	712	712	712	712	712	712	712	712	712	712
Wind	0	0	0	0	0	0	0	0	0	0	0
Solar	45	43	41	39	37	35	13	12	11	11	10
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	165	160	143	138	133	129	125	121	100	96	94
Demand Response	52	52	51	50	49	49	48	47	46	46	45
Transfers	469	310	491	366	567	653	663	627	708	607	765
West Existing Resources	**2,159**	**1,992**	**2,153**	**2,021**	**2,213**	**2,293**	**2,276**	**2,235**	**2,293**	**2,187**	**2,341**
Additional Proxy/Short-Term Purcha	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Wind	111	111	110	110	109	109	109	108	108	107	107
Solar	1,235	1,444	1,382	1,320	1,259	1,197	1,208	1,140	1,074	1,008	942
Storage	1,466	1,444	1,431	1,569	1,551	1,576	1,617	1,881	2,001	2,130	2,102
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	50	50	85	107	108	128	138	141	142	170	175
West Planned Resources	**2,861**	**3,048**	**3,008**	**3,106**	**3,027**	**3,010**	**3,071**	**3,270**	**3,325**	**3,415**	**3,327**
West Total Resources	**5,020**	**5,040**	**5,161**	**5,127**	**5,240**	**5,303**	**5,347**	**5,505**	**5,618**	**5,603**	**5,668**
Load	4,944	5,009	5,082	5,189	5,258	5,330	5,397	5,473	5,660	5,651	5,730
Distributed Generation	(163)	(177)	(192)	(206)	(221)	(234)	(249)	(263)	(277)	(290)	(304)
Energy Efficiency	(394)	(426)	(378)	(502)	(457)	(461)	(475)	(399)	(473)	(463)	(471)
West Total obligation	**4,388**	**4,406**	**4,512**	**4,481**	**4,581**	**4,635**	**4,674**	**4,812**	**4,910**	**4,897**	**4,955**
West Reserve Margin	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%	14.4%

System

Total Resources	14,992	15,826	15,621	15,961	16,299	16,522	16,788	16,959	17,318	17,653	17,658
Obligation	12,304	12,396	12,810	12,610	12,699	12,791	12,876	13,393	13,403	13,425	13,564
Planning Reserves (14.4%)	1,772	1,785	1,845	1,816	1,829	1,842	1,854	1,929	1,930	1,933	1,953
Obligation + Reserves	14,076	14,181	14,654	14,426	14,528	14,633	14,730	15,321	15,333	15,358	15,518
System Position	917	1,645	967	1,536	1,771	1,888	2,059	1,638	1,985	2,295	2,141
Reserve Margin	**21.8%**	**27.7%**	**21.9%**	**26.6%**	**28.3%**	**29.2%**	**30.4%**	**26.6%**	**29.2%**	**31.5%**	**30.2%**

Table 9.13 – Preferred Portfolio Winter Capacity Load and Resource Balance (2025-2034)

East	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Coal	4,147	3,733	3,733	3,498	3,184	3,014	3,014	3,015	3,015	3,015
Gas	3,003	3,334	3,334	3,335	3,526	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33
Wind	2,037	1,929	1,836	1,748	1,616	1,456	1,377	1,300	1,226	1,154
Solar	77	104	101	98	95	92	89	86	83	80
Other Renewable	41	39	38	37	35	34	33	31	30	28
Storage	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	186	181	177	171	167	162	155	150	130	125
Demand Response	139	135	132	129	125	122	119	116	112	109
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,281)	(1,299)	(1,403)	(1,600)	(1,600)	(1,176)	(1,225)	(1,002)
East Existing Resources	**8,062**	**7,890**	**8,104**	**7,749**	**7,379**	**6,841**	**6,748**	**7,083**	**6,931**	**7,070**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	2	2	2	2	2	2
Wind	0	0	0	225	484	691	672	688	666	645
Solar	0	0	0	0	0	0	0	0	0	0
Storage	0	0	90	113	173	821	983	1,003	1,093	1,178
Nuclear	0	0	0	0	0	300	300	300	300	300
Demand Response	0	0	0	73	92	106	106	127	127	157
East Planned Resources	**0**	**0**	**90**	**412**	**750**	**1,920**	**2,063**	**2,120**	**2,188**	**2,283**
East Total Resources	**8,062**	**7,890**	**8,194**	**8,161**	**8,129**	**8,760**	**8,811**	**9,202**	**9,119**	**9,353**
Load	5,724	6,099	6,174	6,448	6,759	6,698	6,869	7,153	7,223	7,397
Distributed Generation	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Energy Efficiency	(63)	(116)	(174)	(243)	(311)	(385)	(403)	(528)	(613)	(695)
East Total obligation	**5,659**	**5,981**	**5,997**	**6,201**	**6,443**	**6,306**	**6,459**	**6,617**	**6,601**	**6,693**
East Reserve Margin	42.5%	31.9%	36.6%	31.6%	26.2%	38.9%	36.4%	39.1%	38.1%	39.7%
West										
Coal	147	147	147	147	147	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726
Wind	64	61	59	57	54	52	50	47	45	43
Solar	1	1	1	1	1	1	0	0	0	0
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	68	68	60	60	57	56	56	55	55	55
Demand Response	0	0	0	0	0	0	0	0	0	0
Transfers	1,600	1,600	1,281	1,299	1,403	1,600	1,600	1,176	1,225	1,002
West Existing Resources	**3,341**	**3,339**	**3,010**	**3,026**	**3,124**	**3,171**	**3,167**	**2,740**	**2,787**	**2,561**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	64	64	64	112	111	111
Solar	0	0	34	57	55	158	259	340	331	316
Storage	0	0	1,102	1,197	1,180	1,200	1,182	1,538	1,517	1,770
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	0	6	9	42	44	44	48	49	49	50
West Planned Resources	**0**	**6**	**1,146**	**1,297**	**1,343**	**1,466**	**1,553**	**2,039**	**2,008**	**2,248**
West Total Resources	**3,341**	**3,345**	**4,156**	**4,322**	**4,467**	**4,637**	**4,720**	**4,778**	**4,794**	**4,809**
Load	3,711	3,577	3,676	3,859	4,025	4,478	4,541	4,421	4,477	4,526
Distributed Generation	(0)	(0)	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)
Energy Efficiency	(45)	(79)	(118)	(157)	(199)	(246)	(236)	(328)	(370)	(407)
West Total obligation	**3,665**	**3,498**	**3,558**	**3,701**	**3,825**	**4,230**	**4,303**	**4,091**	**4,105**	**4,117**
West Reserve Margin	-8.8%	-4.4%	16.8%	16.8%	16.8%	9.6%	9.7%	16.8%	16.8%	16.8%
System										
Total Resources	11,404	11,235	12,350	12,484	12,596	13,397	13,531	13,980	13,913	14,161
Obligation	9,324	9,479	9,555	9,902	10,268	10,537	10,762	10,708	10,706	10,810
Planning Reserves (16.8%)	1,566	1,593	1,605	1,663	1,725	1,770	1,808	1,799	1,799	1,816
Obligation + Reserves	10,891	11,072	11,160	11,565	11,993	12,307	12,570	12,507	12,505	12,626
System Position	513	163	1,190	919	604	1,091	960	1,474	1,408	1,536
Reserve Margin	**22.3%**	**18.5%**	**29.3%**	**26.1%**	**22.7%**	**27.2%**	**25.7%**	**30.6%**	**30.0%**	**31.0%**

Table 9.14 – Preferred Portfolio Winter Capacity Load and Resource Balance (2035-2045)

East	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015	3,015
Gas	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527	3,527
Hydroelectric	33	33	33	33	33	33	33	33	33	33	33
Wind	1,082	1,014	948	883	820	674	621	570	522	474	429
Solar	77	74	71	68	66	63	60	57	46	44	41
Other Renewable	27	26	24	8	8	8	7	6	6	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	121	103	98	95	91	87	83	79	75	72	68
Demand Response	106	103	99	96	93	89	86	83	80	76	73
Sale	0	0	0	0	0	0	0	0	0	0	0
Transfers	(911)	(1,183)	(1,390)	(789)	(927)	(938)	(950)	(1,006)	(965)	(865)	(921)
East Existing Resources	**7,078**	**6,712**	**6,426**	**6,936**	**6,725**	**6,558**	**6,481**	**6,365**	**6,339**	**6,375**	**6,265**
Additional Proxy/Short-Term Purcha	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	2	2	3	3	3	3	3	3	3	3	3
Wind	625	1,530	1,476	1,436	1,383	1,329	1,273	1,286	1,447	1,378	1,311
Solar	0	81	78	75	71	68	65	62	59	55	52
Storage	1,242	1,239	1,234	1,552	2,008	2,312	2,628	2,623	2,880	3,203	3,277
Nuclear	301	301	301	301	301	301	301	301	301	301	302
Demand Response	172	181	189	198	230	241	251	265	294	307	401
East Planned Resources	**2,342**	**3,334**	**3,281**	**3,564**	**3,996**	**4,254**	**4,521**	**4,540**	**4,983**	**5,247**	**5,345**
East Total Resources	**9,420**	**10,046**	**9,707**	**10,500**	**10,721**	**10,812**	**11,001**	**10,905**	**11,322**	**11,622**	**11,610**
Load	7,321	7,508	7,595	7,732	7,856	7,991	8,169	8,340	8,450	8,525	8,664
Distributed Generation	(11)	(11)	(12)	(13)	(13)	(14)	(14)	(14)	(15)	(15)	(16)
Energy Efficiency	(580)	(891)	(834)	(824)	(879)	(926)	(1,042)	(979)	(1,305)	(1,268)	(1,195)
East Total obligation	**6,730**	**6,606**	**6,749**	**6,896**	**6,964**	**7,052**	**7,113**	**7,347**	**7,131**	**7,242**	**7,453**
East Reserve Margin	40.0%	52.1%	43.8%	52.3%	54.0%	53.3%	54.7%	48.4%	58.8%	60.5%	55.8%
West											
Coal	0	0	0	0	0	0	0	0	0	0	0
Gas	735	735	735	735	735	735	735	735	735	735	735
Hydroelectric	726	726	726	726	726	726	726	726	726	726	726
Wind	41	39	36	34	32	30	28	26	24	22	20
Solar	0	0	0	0	0	0	0	0	0	0	0
Other Renewable	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	53	53	52	51	51	50	50	49	49	49
Demand Response	0	0	0	0	0	0	0	0	0	0	0
Transfers	911	1,183	1,390	789	927	938	950	1,006	965	865	921
West Existing Resources	**2,467**	**2,736**	**2,940**	**2,336**	**2,471**	**2,480**	**2,489**	**2,542**	**2,499**	**2,397**	**2,451**
Additional Proxy/Short-Term Purcha	0	0	0	0	0	0	0	0	0	0	0
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0	0
Wind	111	110	110	109	109	109	108	108	107	107	106
Solar	301	349	331	312	294	276	274	254	235	215	195
Storage	1,893	1,865	1,845	2,021	1,997	2,027	2,076	2,412	2,564	2,722	2,685
Nuclear	0	0	0	0	0	0	0	0	0	0	0
Demand Response	50	50	85	107	108	128	138	141	142	170	175
West Planned Resources	**2,355**	**2,374**	**2,372**	**2,549**	**2,508**	**2,539**	**2,596**	**2,914**	**3,048**	**3,213**	**3,162**
West Total Resources	**4,822**	**5,109**	**5,312**	**4,886**	**4,979**	**5,018**	**5,085**	**5,456**	**5,547**	**5,610**	**5,613**
Load	4,773	4,920	4,989	4,941	5,062	5,136	5,276	5,289	5,398	5,345	5,467
Distributed Generation	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)	(4)
Energy Efficiency	(642)	(543)	(439)	(755)	(796)	(837)	(919)	(614)	(645)	(538)	(658)
West Total obligation	**4,128**	**4,374**	**4,548**	**4,183**	**4,263**	**4,297**	**4,353**	**4,671**	**4,749**	**4,803**	**4,805**
West Reserve Margin	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%	16.8%
System											
Total Resources	14,241	15,155	15,018	15,386	15,700	15,830	16,086	16,361	16,869	17,232	17,223
Obligation	10,858	10,980	11,297	11,079	11,227	11,348	11,466	12,018	11,880	12,045	12,258
Planning Reserves (16.8%)	1,564	1,581	1,627	1,595	1,617	1,634	1,651	1,731	1,711	1,735	1,765
Obligation + Reserves	12,422	12,561	12,924	12,674	12,843	12,983	13,117	13,749	13,591	13,780	14,023
System Position	1,820	2,594	2,095	2,711	2,857	2,848	2,969	2,612	3,278	3,452	3,200
Reserve Margin	**31.2%**	**38.0%**	**32.9%**	**38.9%**	**39.8%**	**39.5%**	**40.3%**	**36.1%**	**42.0%**	**43.1%**	**40.5%**

Integrated Portfolio Resource Comparisons by Technology and Year

Table 9.15 through Table 9.25 report the incremental capacity of each technology type for each integrated portfolio and integrated variant portfolio. Table 9.26 through Table 9.28 report the capacity of coal generating units that are retired, converted to natural gas fueling, or augmented with carbon capture technology.

Table 9.15 – New Gas[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	489	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	40	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	40	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operations

Table 9.16 - Nuclear[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operations

Table 9.17 – Renewable Peaking[1]

Study	Cumulative Energy, Gwh																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operations

Table 9.18 – DSM – Energy Efficiency

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	89	89	238	262	270	285	342	329	308	282	265	255	250	233	220	208	201	232	283	269	239
MR Base	89	89	238	259	266	285	338	329	308	282	265	249	250	239	227	214	210	235	286	271	239
MN - No Coal Post 2032	89	89	238	259	266	281	336	329	303	282	265	248	250	234	220	208	201	232	283	269	240
MN - No CCS	89	89	238	262	270	285	343	329	308	282	270	255	250	234	220	208	202	232	287	272	239
MN - No Nuclear	89	89	238	262	275	289	345	331	308	283	265	252	250	233	227	214	207	235	286	275	239
MN - Offshore Wind	89	89	238	259	270	285	338	329	308	283	265	252	250	233	219	208	207	232	283	271	236
LN Base	89	89	237	257	265	280	334	328	307	281	264	254	249	232	218	206	199	225	276	266	227
HH Base	89	89	244	268	276	291	347	333	312	286	268	268	261	243	229	217	210	235	286	272	240
SC Base	89	89	244	265	272	286	347	333	310	283	265	258	252	240	227	209	210	234	286	271	235

Table 9.19 – DSM – Demand Response

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	18	40	11	144	33	81	13	36	2	46	24	12	66	76	42	51	46	33	71	63	144
MR Base	18	40	11	126	43	76	12	39	2	46	16	12	80	80	42	48	48	34	71	43	62
MN - No Coal Post 2032	18	40	11	141	32	60	47	27	2	46	16	12	66	84	42	48	48	34	71	62	43
MN - No CCS	18	40	11	139	38	81	13	36	2	46	24	12	66	76	45	48	60	68	23	153	53
MN - No Nuclear	18	40	19	126	53	94	23	21	18	39	16	1	136	28	42	77	23	29	72	62	144
MN - Offshore Wind	18	40	23	135	38	49	7	37	18	30	24	1	136	47	42	72	24	28	79	61	43
LN Base	18	40	25	138	53	34	13	36	18	31	16	21	85	76	43	50	46	33	72	118	88
HH Base	18	40	23	134	45	34	13	36	2	50	16	12	105	25	39	104	50	19	81	28	65
SC Base	18	40	13	27	115	21	82	26	2	46	16	1	32	91	94	30	67	27	77	27	40

Table 9.20 – Utility Scale Wind[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	486	804	-	-	451	-	-	3	2,327	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	1,417	594	-	-	451	-	-	3	2,954	187	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	1,077	594	153	78	350	-	-	2	3,132	178	-	-	-	-	-	-	-	-
MN - No CCS	-	-	439	970	602	-	-	-	-	-	273	2,634	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	422	834	-	-	412	-	-	199	1,374	616	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	452	792	-	200	-	41	-	270	864	1,126	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	594	-	-	-	-	-	3	3,015	-	-	-	-	-	-	-	-	-
HH Base	-	-	1,187	721	975	233	-	451	-	-	3	2,492	-	-	-	-	-	-	-	-	-
SC Base	-	-	1,417	-	594	-	-	451	-	-	297	3,236	152	-	-	-	-	-	-	-	-

[1] Positive values indicate installed capacity in the first full year of operations

Table 9.21 – Small Scale Wind[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	236	802	-	-
MR Base	-	-	-	-	-	745	-	60	52	-	-	300	98	9	9	-	-	552	28	414	40
MN - No Coal Post 2032	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	176	660
MN - No CCS	-	-	-	-	380	505	4	85	-	-	-	246	4	37	9	-	-	-	-	176	660
MN - No Nuclear	-	-	-	-	-	246	7	-	-	-	21	207	111	17	9	-	-	-	-	105	211
MN - Offshore Wind	-	-	-	-	-	113	-	-	-	-	-	-	-	-	-	-	-	79	1	-	-
LN Base	-	-	-	-	500	349	34	26	-	29	29	29	41	33	9	109	-	-	-	194	660
HH Base	-	-	-	-	133	876	89	-	-	-	14	172	76	75	49	-	402	486	120	125	37
SC Base	-	-	20	-	302	616	35	89	1	-	8	215	32	103	119	-	-	875	92	-	454

[1] Positive values indicate installed capacity in the first full year of operations

Table 9.22 – Utility Solar[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	245	182	-	848	896	805	49	5	-	2,221	4	-	-	-	237	-	-	-	-
MR Base	-	-	137	107	-	505	794	1,081	522	1	-	2,736	2	406	-	-	237	-	-	-	-
MN - No Coal Post 2032	-	-	245	182	-	848	896	805	87	5	480	4,291	4	-	-	-	237	-	-	-	-
MN - No CCS	-	-	245	182	-	848	896	805	567	5	-	4,291	2	-	-	-	237	-	-	-	-
MN - No Nuclear	-	-	290	237	-	44	181	451	521	2	2,079	2,103	4	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	297	101	-	385	411	634	521	4	-	405	4	-	-	670	-	-	393	-	-
LN Base	-	-	136	317	49	683	985	452	522	300	105	1	4	6	-	-	231	-	-	-	-
HH Base	-	-	419	411	-	546	2,865	452	4	1	-	2,648	800	406	-	-	237	-	-	-	-
SC Base	-	-	336	500	-	281	1,156	415	55	1	66	3,363	1,584	564	139	-	237	793	-	-	-

[1] Positive values indicate installed capacity in the first full year of operations

Table 9.23 – Small Scale Solar[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	61	-	110	-	27	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	591	-	1	26	17	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	731	55	72	-	-	3	165	54	8	9	-	-	-	-	-	244
LN Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,121
SC Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	156

[1] Positive values indicate installed capacity in the first full year of operations

Table 9.24 – Battery Storage[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	520	1,297	116	-	39	-	416	3	317	176	-	11	253	10	81	105	488	257	279	15
MR Base	-	520	1,135	26	181	390	108	537	37	197	277	-	176	341	73	81	79	651	589	639	15
MN - No Coal Post 2032	-	520	1,297	116	-	19	4	639	12	71	365	-	56	602	220	422	128	227	242	411	17
MN - No CCS	-	520	1,297	16	43	19	4	464	14	242	389	-	438	417	65	488	214	214	355	592	15
MN - No Nuclear	-	520	734	124	318	879	110	317	15	309	148	-	-	314	14	861	174	95	108	43	96
MN - Offshore Wind	-	520	1,360	328	220	558	140	69	122	118	47	-	-	127	10	1,067	322	405	313	244	15
LN Base	-	520	1,235	160	3	-	-	401	6	242	546	156	368	245	412	863	211	456	380	851	9
HH Base	-	520	1,133	66	108	347	141	452	141	12	200	-	74	50	12	193	136	505	399	276	34
SC Base	-	520	1,011	98	-	708	2	592	91	14	181	-	13	313	307	94	393	41	370	695	139

[1] Positive values indicate installed capacity in the first full year of operations

Table 9.25 – Long Duration Storage[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	1	26	62	655	166	22	93	88	67	-	-	326	466	312	325	-	264	332	80
MR Base	-	-	-	-	-	378	-	-	-	-	-	-	-	60	167	496	261	50	108	71	-
MN - No Coal Post 2032	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80
MN - No CCS	-	-	1	26	62	655	166	22	93	88	67	-	-	130	174	634	381	97	277	332	80
MN - No Nuclear	-	-	251	109	-	123	249	97	-	258	126	-	36	152	120	277	229	246	160	104	33
MN - Offshore Wind	-	-	45	15	79	166	-	31	-	339	178	-	-	382	675	305	206	274	327	362	122
LN Base	-	-	93	-	2	803	151	66	102	58	-	-	-	58	94	554	89	109	257	345	23
HH Base	-	-	-	-	-	243	-	-	-	86	131	-	274	375	106	555	-	-	135	346	90
SC Base	-	-	-	-	-	197	-	-	-	103	78	-	24	-	14	399	130	469	373	108	-

[1] Positive values indicate installed capacity in the first full year of operations

Table 9.26 – Majority Owned Coal Retirements[1]

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	(220)	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	(220)	-	-	-	(268)	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

[1] Negative values indicate retirement of coal capacity

Table 9.27 – Carbon Capture and Sequestration Selections

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(264)
HH Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	-	-	-	-	526	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 9.28 – Coal to Gas Conversion Selections

Study	Installed Capacity, MW																				
	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MN Base	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MR Base	-	357	-	-	205	2,397	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Coal Post 2032	-	357	-	-	205	3,097	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No CCS	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - No Nuclear	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MN - Offshore Wind	-	357	-	-	205	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
LN Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HH Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SC Base	-	357	-	-	205	330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Preferred Portfolio Variants

Driven by emergent federal and state law and stakeholder interest, the 2025 IRP features 9 preferred portfolio variants developed to analyze key resource and transmission decisions. The iterative deterministic process consistently yields portfolios that are reliable once proxy resources are available for selection. As a consequence, there is no meaningful comparison of unserved energy between the various portfolios, and cost and risk comparison tables below do not include a measure of ENS.

Table 9.29 – Preferred Portfolio Variant Studies

Variant	Description
No CCS	No coal units are able to select CCS technology
No Nuclear	No nuclear resources are eligible for selection
No Coal 2032	All coal must retire or gas convert by January 1, 2032
Offshore Wind	Counterfactual to the Preferred Portfolio selection
All Coal End of Life	Current coal units cannot gas convert OR select CCS
No New Gas	Proxy gas plants are not eligible for selection
Force All Gas Conversions	All coal plants that can gas convert, must
No Forward Technology	Nuclear, Hydrogen and Biodiesel units are not eligible

Table 9.30 summarizes the cost and risk results of the variant studies under expected conditions represented by the MN (medium gas price/no CO_2) price-policy scenario.

Table 9.30 – Initial and Variant Cases Under Medium Gas/ Zero CO_2

	ST Value			CO2 Emissions		
Case - MN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base MN	22,930	0	1	220,325	66,013	5
Integrated No Coal Post 2032 MN	23,844	914	4	154,979	668	2
Integrated No CCS MN	23,199	269	3	218,003	63,691	4
Integrated Offshore Wind MN	29,231	6,301	6	216,728	62,417	3
Integrated No Nuclear MN	24,295	1,365	5	239,932	85,621	6
Integrated Base MR	22,985	55	2	154,311	0	1

Table **9.31**, below, summarizes the cost and risk results of the variant studies under conditions represented by the LN (low gas price/zero CO_2) price-policy scenario.

Table 9.31 – Initial and Variant Cases Under Low Gas/ Zero CO_2

Case - LN	ST Value			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base LN**						
Integrated Base MN	20,981	101	2	215,698	38,760	5
Integrated No Coal Post 2032 MN	21,598	718	4	178,027	1,089	2
Integrated No CCS MN	21,470	589	3	204,546	27,608	3
Integrated Offshore Wind MN	27,395	6,515	6	208,244	31,305	4
Integrated No Nuclear MN	22,085	1,205	5	235,603	58,664	6
Integrated Base MR	20,880	0	1	176,938	0	1

**The Integrated LN Base case was not able to evaluated in ST prior to publishing the draft. The comparative data for this table will be provided prior to final publication.

Table 9.32 summarizes the cost and risk results of the variant studies under conditions represented by the HH (high gas price/high CO_2) price-policy scenario. Summarized results include energy shortfalls and emissions metrics.

Table 9.32 – Initial and Variant Cases Under High Gas/ High CO_2

Case - HH	ST Value			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base HH	25,554	0	1	121,431	0	1
Integrated Base MN	27,549	1,995	5	141,740	20,308	6
Integrated No Coal Post 2032 MN	27,315	1,760	3	129,468	8,037	2
Integrated No CCS MN	27,351	1,797	4	132,543	11,111	4
Integrated Offshore Wind MN	33,701	8,146	7	140,389	18,957	5
Integrated No Nuclear MN	29,601	4,047	6	147,714	26,283	7
Integrated Base MR	26,776	1,222	2	130,846	9,414	2

Table 9.33 summarizes the cost and risk results of the variant studies under conditions represented by the SCGHG (medium gas price/social cost of greenhouse gas) price-policy scenario. Summarized results include energy shortfalls and emissions metrics.

Table 9.33 – Initial and Variant Cases Under Medium Gas/ Social Cost of CO_2

	ST Value			CO2 Emissions		
Case - SC	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Integrated Base SC	29,603	0	1	61,102	0	1
Integrated Base MN	30,766	1,163	3	68,506	7,404	5
Integrated No Coal Post 2032 MN	30,773	1,170	4	62,173	1,071	3
Integrated No CCS MN	30,665	1,062	2	61,948	847	2
Integrated Offshore Wind MN	36,933	7,330	6	66,925	5,823	4
Integrated No Nuclear MN	32,606	3,003	5	71,961	10,859	6

Initial and Variant Cases Under Medium Gas/ Federal Regulation (MR)

The only variant cases which would be compliant under the current language in EPA 111(d) are the MR case and the No Coal Post 2032 case. The Base MR portfolio is $807 million less in PVRR than the No Coal Post 2032 portfolio when dispatched under the MR gas and market pricing structure. CO_2 emissions are 972 tons higher in the Base MR portfolio than the No Coal post 2032 portfolio.

Variant Study Analysis

No CCS Variant

This variant does not allow Jim Bridger 3 and 4 to convert to CCS during the study horizon. The Jim Bridger units are allowed to either operate as base coal fired with no additional equipment installed, or to convert to gas in 2030. The analysis explores the potential costs and benefits of alternatives to CCS at Jim Bridger 3 and 4 if CCS were not to be commercially viable at these locations.

Figure 9.15 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is not allowed on the system starting in 2032. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. When Jim Bridger units 3 and 4 do not convert to CCS, they continue to run as coal. Given the lower capacity factor of coal plants without CCS, additional resources are needed over the course of the horizon to generate enough energy to meet retail demand. This results in 1,447 MW of additional wind, 2,588 MW of additional solar and 1,420 MW of additional storage as compared to the integrated MN view.

Figure 9.15 - Increase/(Decrease) in Proxy Resources with No CCS

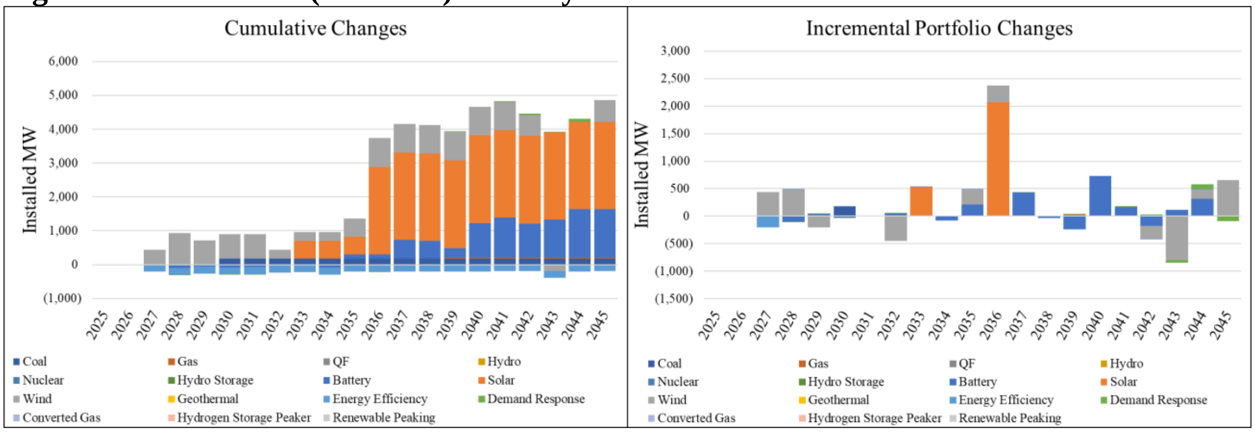
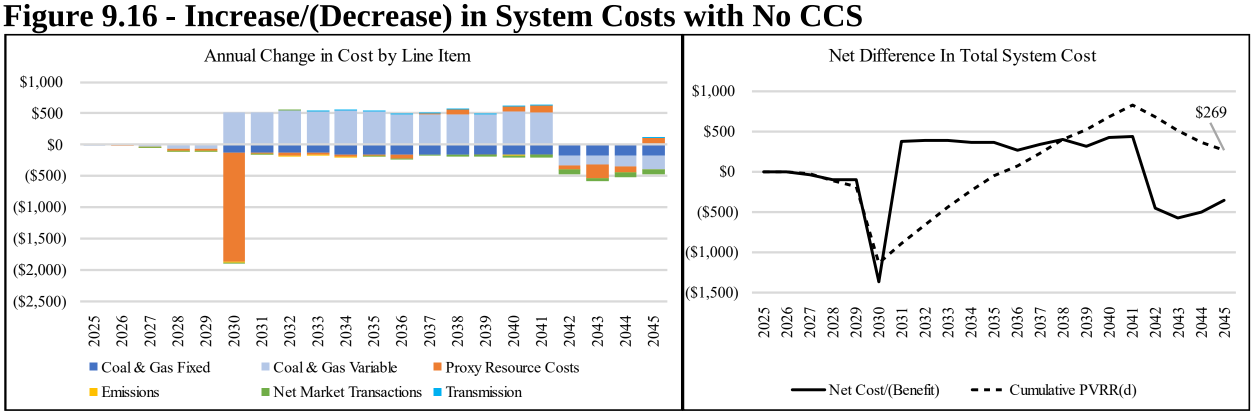


Figure 9.16 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when CCS is removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When CCS is removed from the portfolio, the resulting portfolio has a $269 million increase in costs compared to the preferred portfolio.

Despite the significant reduction in capital cost without installing CCS, the loss of the 45Q tax credits more than overtakes the capital savings over the course of the 21-year study period.

Figure 9.16 - Increase/(Decrease) in System Costs with No CCS



No Nuclear Variant

This variant does not allow the Natrium™ demonstration nuclear project to be selected as a resource option in 2030. Additionally, this variant does not allow any other nuclear to be selected as a potential replacement of the Natrium™ project. The analysis explores the potential costs and benefits of replacement resource options should the Natrium™ demonstration or other nuclear project prove not to be commercially viable..

Figure 9.17 shows the cumulative (at left) and incremental (at right) portfolio changes when nuclear options are not allowed on the system. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Given the currently selected nuclear siting at Naughton, overall portfolio changes are somewhat smaller than in cases where significant coal changes are tested. The variant case selects 40 MW of new gas peaking resources, an additional 468 MW of energy efficiency, 998 fewer MW of wind which is offset by 1,293 additional MW of solar. Finally an additional 81 MW of storage is selected.

Figure 9.17 - Increase/(Decrease) in Proxy Resources with No Nuclear

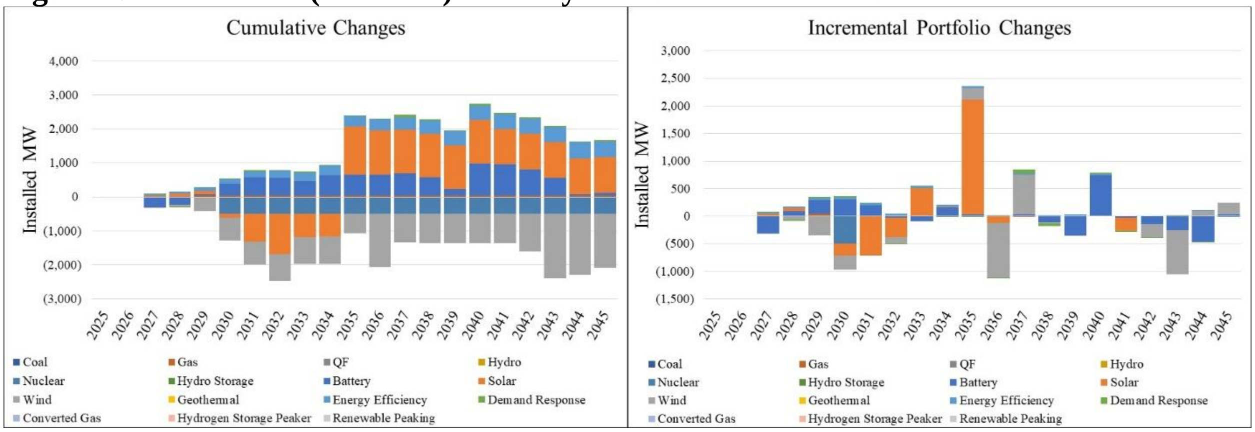
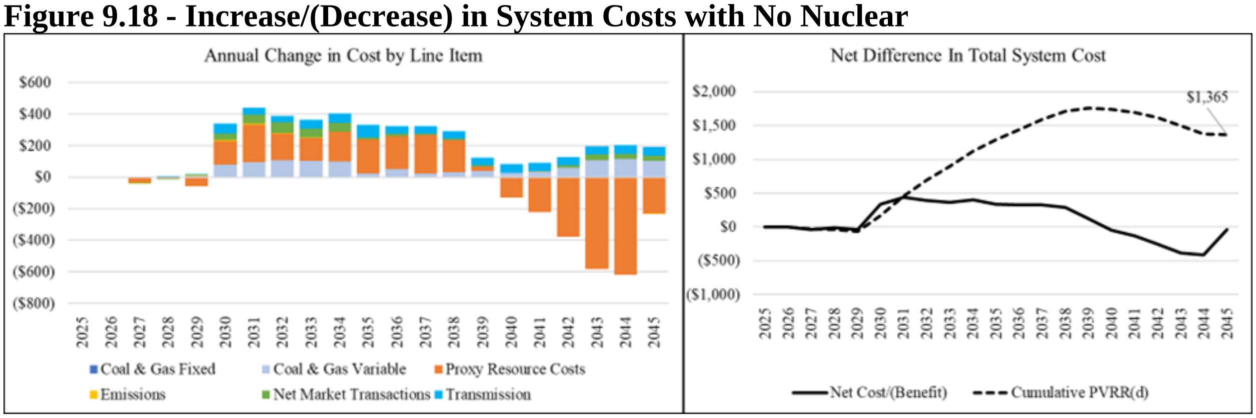


Figure 9.18 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when nuclear projects are removed from the portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When the Natrium™ demonstration project is removed from the portfolio, the resulting portfolio has a $1.365 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.18 below, these increases come primarily from significant early proxy resource additions needed to offset the loss of firm nuclear capacity. Although there is an eventual decrease in proxy resource costs in the final years of the study horizon, the need for early investment overcomes these later potential savings.

Figure 9.18 - Increase/(Decrease) in System Costs with No Nuclear



No Coal Post 2032 Variant

This variant does not allow coal to be on the system in any form after 2032. This means current coal facilities must either convert from coal fired to gas fired or retire. In this view, CCS was not allowed as this would still result in the unit using coal fuel. The analysis explores the potential costs and benefits of early retirement or conversion of the entirety of the coal fleet. This variant is distinct from the medium gas with federal regulation (MR) price policy study in that it does not allow for CCS while the MR does allow for CCS.

Figure 9.19 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is not allowed on the system starting in 2032. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. Due to the significant changes to the operating characteristics of more than 3,300 MW of the existing coal fleet, large portfolio changes occur. The variant case selects new gas peaking resources whereas the integrated MN view does not. Additionally, more solar and wind is selected in the variant, and less long duration storage is partially offset by additional 4 hour storage.

Figure 9.19 - Increase/(Decrease) in Proxy Resources with No Coal Post 2032

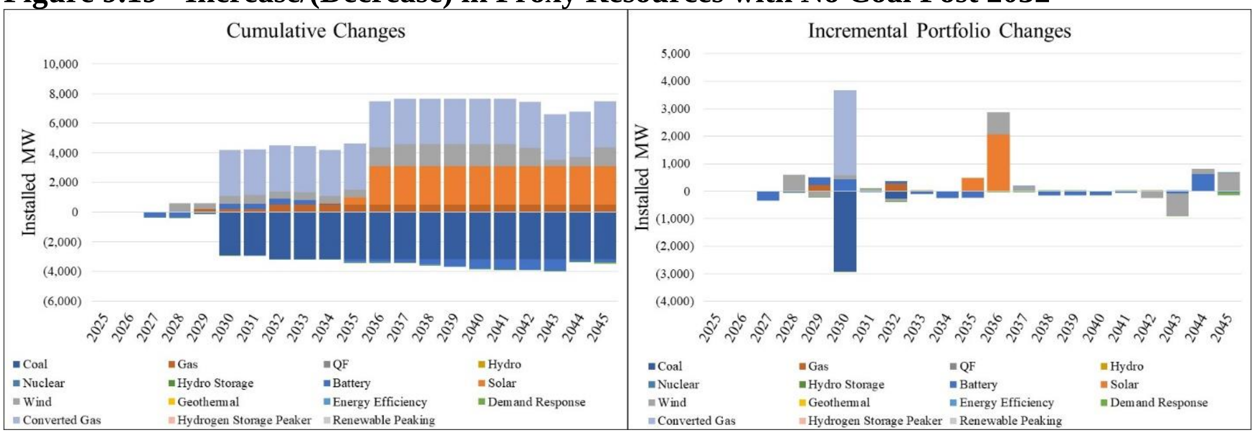
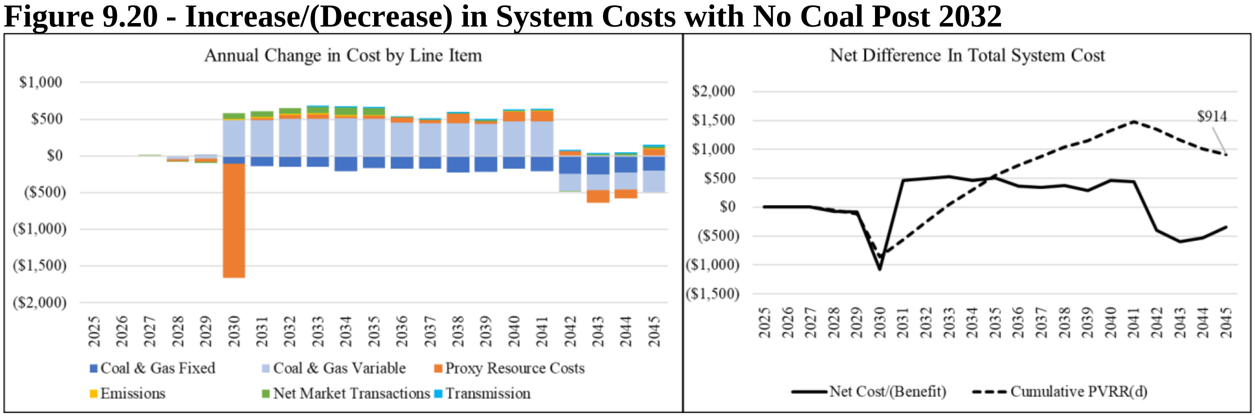


Figure 9.20 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when coal is no longer allowed in the portfolio after 2032. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When all coal must be retired or gas converted by 2032, the resulting portfolio has a $914 million increase in costs compared to the preferred portfolio.

As seen in Figure 9.20 below, like in the No CCS case, the loss of 45Q tax credits more than offsets the reduced capital cost to install CCS. Additionally, this case has higher levels of market purchases, and additionally has higher proxy resource costs in nearly all years of the study horizon.

Figure 9.20 - Increase/(Decrease) in System Costs with No Coal Post 2032



Force Offshore Wind

Since offshore wind was not selected in any of the integrated MN jurisdictional runs, this variant serves as a counterfactual forcing this resource into all jurisdictional runs. The analysis explores the potential costs and benefits of replacing resources selected in various jurisdictional runs with a higher capacity factor offshore wind resource.

Figure 9.21 shows the cumulative (at left) and incremental (at right) portfolio changes when offshore wind is forced into the portfolio in 2030. A positive value indicates an increase in resources and a negative value indicates a decrease when a resource is reduced or eliminated. The higher capacity factor of the offshore wind resource results in 300 MW less utility scale wind being selected in the portfolio compared to the preferred portfolio. Additionally, the portfolio has 1,669 MW less utility scale solar. Less small scale wind is offset by more small scale solar. For capacity and reliability needs, 1,824 more MW of storage is selected in the offshore wind case, 1,603 MW of which is 4 hour storage. Retirements are the same between the studies.

Figure 9.21 - Increase/(Decrease) in Proxy Resources with Offshore Wind

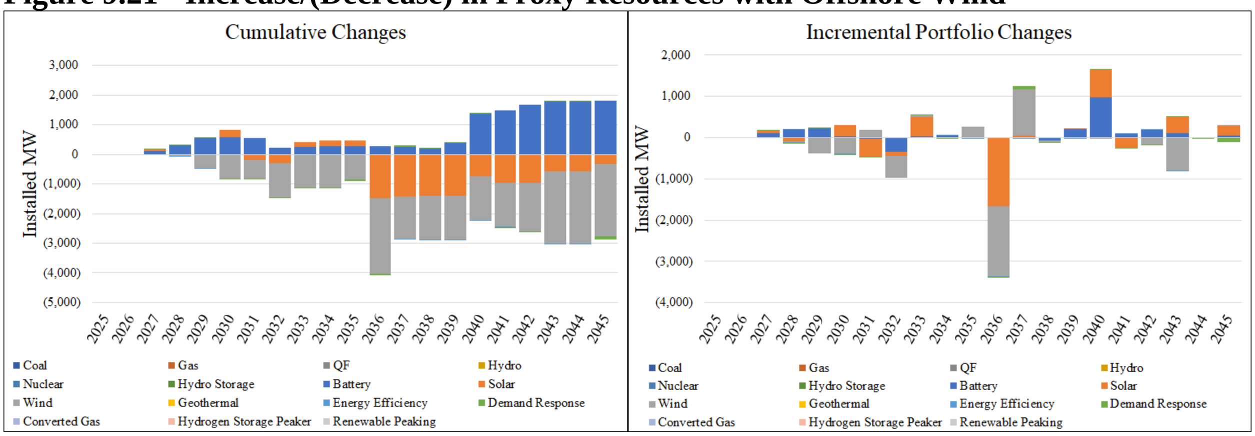
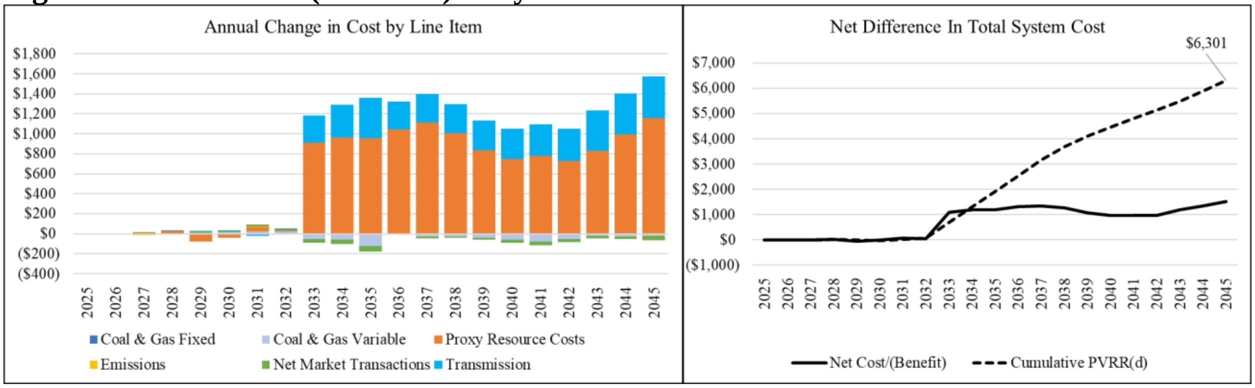


Figure 9.22 summarizes changes in system costs, based on ST model results using MN price-policy assumptions, when offshore wind is forced into the various jurisdictional portfolios. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). When offshore wind and the required Coos Bay area transmission upgrades are forced into the portfolio, the resulting portfolio has a $6.301 billion increase in costs compared to the preferred portfolio.

As seen in Figure 9.22 below, these increases come primarily from higher overall proxy resource costs, driven by a reduction in production tax credit generating resources. Since the offshore wind resource receives an investment tax credit the loss of production tax credits on approximately 2,900 MW of renewable resources is significant. The balance of the cost in this portfolio is related to the significant overall transmission investments required to enable both the offshore wind resource itself, but also the various transmission upgrades which are required to enable the offshore wind specific transmission line.

Figure 9.22 - Increase/(Decrease) in System Costs with Offshore Wind



Additional Sensitivity Analysis

Note – Sensitivity cases, which are not eligible for selection as the preferred portfolio, are under development and will be evaluated and included in the March 31, 2025 filing of the 2025 IRP. The list of planned sensitivities is described below.

In addition to the resource portfolios developed and studied as part of the portfolio-development process that supports selection of the preferred portfolio, sensitivity cases were developed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. These sensitivity cases are also useful as "bookend" analysis to aid in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risks.

Table S.1 lists additional sensitivity studies to be performed for the 2025 IRP. To isolate the impact of a given planning assumption, all sensitivity cases will be evaluated with the preferred portfolio.

Table S.1– Summary of Additional Sensitivity Cases

Sensitivity	Definition
High Load Growth	Base load forecast replaced by a high load version
Low Load Growth	Base load forecast replaced by a low load version
1-20 Peak Load	Base load forecast replaced by a high load version using historical 20 year highest load
High Private Generation	Assumes lower load due to high private generation adoption
Low Private Generation	Assumes higher load due to low private generation adoption
Large Metered Load Growth	Assumes significant large metered customer load growth
Low Cost Renewables	Assumes high adoption of IRA/IIJA benefits leads to large cost declines
Low PTC/ITC eligibility	Assumes changes to IRA/IIJA leading to shorter PTC/ITC eligibility window
All CCS	Allows CCS to be selected at any coal site
Jim Bridger Long Term Fuel	Adjusts the long term fuel plan at Jim Bridger to assess impacts of change
B2H Delayed to 2030	In the Large Metered Load Growth scenario, B2H is not eligible until 2030
Business as Usual	Portfolio if no state requirements existed
Business Plan[9]	First 3 years are aligned with the current business plan

Washington Scenarios

Note – Scenarios required by Washington rule, which are not eligible for selection as the preferred portfolio, are under development and will be evaluated and included in the March 31, 2025 filing of the 2025 IRP. The list of planned sensitivities is described below.

As described in Chapter 8, in addition to the information provided throughout the 2025 IRP, Washington's CETA legislation indicates three key studies and sensitivities be analyzed, in addition to the least-cost, least-risk portfolio developed to meet CETA clean energy standards:[10]

- **Alternative Lowest Reasonable Cost**
- **Maximum Customer Benefit**

WAC 480-100-620(11)(a) specifically requires the utility to demonstrate how the long-range integrated resource plan expects to achieve clean energy transformation standards (WAC 480-100-610 (1) through (3)), and (j), to incorporate the social cost of greenhouse gas emissions as a cost adder as specific in RCW 19.280.030(3). The integrated preferred portfolio includes all resource selections for Washington customers as optimized and determined under the SCGHG price policy that are necessary to achieve a path to CETA compliance.

Additional discussion on how the preferred portfolio meets the requirements set out by CETA statute and puts the company on a path towards greenhouse gas neutrality as depicted by the long-term clean energy interim targets is included in Volume II, Appendix O – Washington Clean Energy Action Plan.

[9] In the 2025 IRP, the business plan sensitivity is aligned with the integrated preferred portfolio due to the base assumptions being aligned. For this reason, no additional sensitivity is needed.
[10] The Washington requirement for a climate change sensitivity which includes climate changes impacts is met by the incorporation of climate change into all 2025 IRP studies.

CHAPTER 10 – DRAFT ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2025 Integrated Resource Plan (IRP) action plan identifies steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio[1]. In its draft form, the action plan is subject to change driven by stakeholder feedback, ongoing review and validation, and changes in the planning environment.
- PacifiCorp's 2025 IRP draft action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).[2]
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2025 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver a least-cost, least-risk portfolio for customers, based on the resources and requirements identified in its preferred portfolio, with a focus on the front five years of the planning horizon.

The 2025 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2025 IRP, such as capital and operating costs, are based upon recent projections of cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the 2025 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2025 IRP acquisition path analysis, this chapter also includes discussion of the following resource procurement topics:

[1] The draft preferred portfolio is subject to change driven by stakeholder feedback, ongoing review and validation, and changes in the planning environment.

[2] Changes in procurement planning and Federal legislative drivers for change were discussed in the 2025 IRP public input meeting series. See Appendix M, stakeholder feedback form #11 (Utah Environmental Caucus). See also Appendix M, stakeholder feedback form #13 (Joan Entwistle).

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;
- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2025 IRP Action Plan

The 2025 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2025 IRP public-input process. Table 10.1 details specific 2021 IRP action items by resource category.

Table 10.1 – 2025 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**<u>Colstrip Units 3 and 4:</u>** • PacifiCorp will continue to work with co-owners to develop the most cost-effective path toward an exit from the Colstrip project in Montana by 2030.
1b	**<u>Craig Unit 1:</u>** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2025 IRP preferred portfolio target exit date of December 31, 2025.
1c	**<u>Naughton Units 1 and 2:</u>** • PacifiCorp will continue the process of converting Naughton Units 1 and 2 to natural gas as initiated in Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**<u>Carbon Capture and Storage / Low Carbon Portfolio Standard:</u>** • PacifiCorp will continue to evaluate the economic and technical feasibility of carbon capture technology on Jim Bridger Units 3 and 4 to comply with Wyoming's low carbon portfolio standard.
1e	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.
1f	**<u>Natrium™ Demonstration Project:</u>** • By the end of 2025, PacifiCorp expects to finalize a commercial off-take agreement for the Natrium™ project. PacifiCorp will continue to monitor key TerraPower development milestones 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.

1g	**<u>Ozone Transport Rule Compliance:</u>** • 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. PacifiCorp will continue to monitor developments in the Utah ozone case and adjust its plans accordingly in response to developments.
1h	**<u>Natural Gas Emissions Compliance Strategies</u>** • The 2025 IRP indicates that changes in accounting and/or dispatch of existing natural gas resources may be a beneficial element of Oregon’s HB 2021 compliance strategy and to align with evolving state policies. A range of implementation strategies exist, with intertwined implications on resource allocation, market participation, and compliance requirements. PacifiCorp will meet with impacted parties, program administrators, and regulators to enable a refined analysis of the available options to prepare for implementation no later than the start of 2030.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from 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 will continue to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp filed an application for approval of a resource solicitation process for the program with the Utah Public Service Commission in November 2024. PacifiCorp plans to file an application for the remainder of the program during Q1 2025.
2b	**2025 All-Source Request for Proposals:** • PacifiCorp will issue as appropriate by jurisdiction need, one or more all-source Request for Proposals (RFP) to procure resources aligned with the 2025 IRP preferred portfolio that can achieve commercial operations by the end of December 2029.[3] • In light of the differentiated resource needs by jurisdiction identified in the 2025 IRP, scope and targeted resource needs may vary by jurisdiction.

Action Item	3. Transmission Action Items
3a	**Local Reinforcement Projects** Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids.
3b	**Gateway West Support** Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.

[3] Procurement strategy was a frequent topic during the 2025 IRP public input meeting process and stakeholder feedback. See Appendix M, stakeholder feedback form #17 (Oregon Public Utilities Commission)

Action Item	4. Demand-Side Management (DSM) Actions
4a	**<u>Energy Efficiency Targets:</u>** • PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2025 IRP. • PacifiCorp will pursue cost-effective energy efficiency resources. • PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio. Capacity impacts for demand response include both summer and winter impacts within a year.

Action Item	5. Market Purchases

5a	**<u>Market Purchases:</u>**
	• PacifiCorp will acquire short-term firm market purchases for on-peak delivery from 2025-2027 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means:
	  ○ Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.
	  ○ Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.
	  ○ Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.

Action Item	6. Renewable Energy Credit (REC) Actions
6a	**<u>Renewable Portfolio Standards (RPS):</u>** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2026 and future compliance periods, as needed.

6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Progress on 2023 Action Plan

This section describes progress that has been made on previous action plan items documented in the 2023 IRP filed with state commissions on May 30, 2023. Many of these action items have been superseded in some form by items identified in the 2025 IRP action plan. The status for all action items from the 2025 IRP is summarized in Table 10.2.

Table 10.2 – 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. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	• 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. • Removal of coal handling equipment and installation of natural gas components began on January 1, 2024. Conversions were completed 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.	• PacifiCorp continues to work with TerraPower on commercial arrangements for offtake from the Natrium™ project and expects to finalize these arrangements by the end of 2025.
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.	• 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.

	• Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023.	
Action Item	**2. New Resource Actions**	**Status**
2a	**<u>Customer Preference Request for Proposals:</u>** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve the 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 applied for approval of a resource solicitation process with the Utah Public Service Commission in November 2024.
2b	**<u>2025 All-Source Request for Proposals:</u>** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the 2025 IRP	The 2025 IRP includes an action item to procure incremental resources as needed to serve customers over the long term.

	preferred portfolio that can achieve commercial operations by the end of December 2030. • In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier.	
2c	**<u>2022 All-Source Request for Proposals:</u>** • In April 2022 PacifiCorp issued an all-source Request for Proposals 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.

Action Item	3. **Transmission Action Items**	**Status**
	• 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. • PacifiCorp contracted on a bi-lateral basis for battery energy storage resources with commercial operation dates prior to summer 2026 and terminated the 2022 All Source Request for Proposals.
3a	**Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):** • In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service.	The Energy Gateway South transmission project is in-service.
3b	**Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):** • In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service. •	The Energy Gateway West Sub-Segment D1 transmission project is in-service.
3c	**Boardman-to-Hemingway (500 kV transmission line):** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement.	PacifiCorp has continued to participate in the support, negotiations, planning and permitting of the Boardman-to-Hemingway 500 kilovolt transmission line, which is targeted for a 2027 in-service date.

	• 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.	
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 to prepare for potential growth in new large loads seeking new service over the next decade.	PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment.

Action Item	4. **Demand-Side Management (DSM) Actions**	**Status**
4a	**<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	• 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

	planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP.	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.
Action Item	5. **Market Purchases**	**Status**
5a	**Market Purchases:** • Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.	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	**<u>Renewable Portfolio Standards (RPS):</u>** • 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	**<u>Renewable Energy Credit Sales:</u>** • 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

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the 2025 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis including load, private generation, changes in available resources, and emissions polices. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2025 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources qualifying for federal income tax credits, market purchases, and energy efficiency and demand response resources are consistently selected, in conjunction with new storage and continued thermal unit operations to mitigate volatility. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2025 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, CO_2 policy also influences resource selections in the 2025 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event, PacifiCorp identifies the planning scenario assumption affecting both short-term (2025-2034) and long-term (2035-2045) resource strategies.

Acquisition Path Decision Mechanism

Note – Acquisition path analysis is heavily dependent upon sensitivity studies which have are not included in the December 31, 2024 Draft 2025 IRP distribution. The purpose and scope of acquisition path analysis is described below, with final sensitivity studies to be provided by March 31, 2025.

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[4] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability and flexibility at a reasonable cost.

[4] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

PacifiCorp's 2025 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

Procurement Delays

The main procurement risk, where a procurement need is indicated, is an inability to procure resources in the required timeframe to maintain reliable and resilient grid operations. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in a given action plan period. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all of the capacity needs.
- Temporarily drop below its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

Consistent with the Utah commission's order in Docket No. 15-035-04, the IRP is directed to include a business plan sensitivity. In the 2025 IRP, a distinct sensitivity would be redundant because the integrated preferred portfolio's base assumptions are aligned with the business plan as set forth the following parameters:

- Over the first three years, resources align with those assumed in PacifiCorp's current Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Resource Procurement Strategy

To acquire resources outlined in the 2023 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs such as load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2023 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use a competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-Side Management[5]

PacifiCorp offers a robust portfolio of demand response and energy efficiency programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp provides Class 4 DSM offerings, and has continued ***watt***smart outreach and communications. Educating customers regarding energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will continue to evaluate how to best incorporate potential DSM programs into the broader all-source RFP process discussed above or whether separate RFPs focused on these resources are warranted based on state-specific requirements and program needs.

[5] Class 1 DSM is most commonly referred to as "demand response" in the 2023 IRP; Class 2 DSM is most commonly referred to as "energy efficiency". Class 4 DSM describes energy efficiency measures achieved through public outreach and education.

Small Scale Renewable Energy Supply

In order to fulfil Oregon regulatory requirements for small-scale renewable resources, PacifiCorp plans to issue a small-scale renewable energy RFP in 2025 to solicit resources within its territory which are 20 MW or smaller and can be commercially operational by 2029. Currently, Oregon's new HB 2021 legislation and associated Clean Energy Plan is driving a specific evaluation of small-scale renewables that may help to identify the costs and benefits of smaller (20 MW or less installed capacity) community-oriented renewables projects across PacifiCorp's service territory. This study is addressed in PacifiCorp's 2023 Oregon Clean Energy Plan.

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time. Because of recent downgrades by credit rating agencies, the increase in debt associated with owned resources could negatively impact PacifiCorp's credit ratios and credit rating.

Alternately and depending on contractual terms, purchasing power from a third party in a long-term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power-purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Power-purchase agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process. While the level of imputation associated with long-term contracts is expected to be lower than the debt associated with owned resources, it still may affect PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives.

Compliance strategies will be affected by how and whether states or the federal government choose to implement further policies related to greenhouse gases and nitrogen oxide. State or federal frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a CO_2 tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as CO_2 capture with sequestration. As mentioned above, plant CO_2 emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; and (2) reduce volatility of net power costs for PacifiCorp's customers. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the chief executive officer of PacifiCorp, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within power volume hedge limits and natural gas percent hedge volume limits.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company’s total generation capacity relative to customer load requirements at a given point in time.

Instruments

PacifiCorp’s hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using historic years to represent uncertainty. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continue to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2025 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.