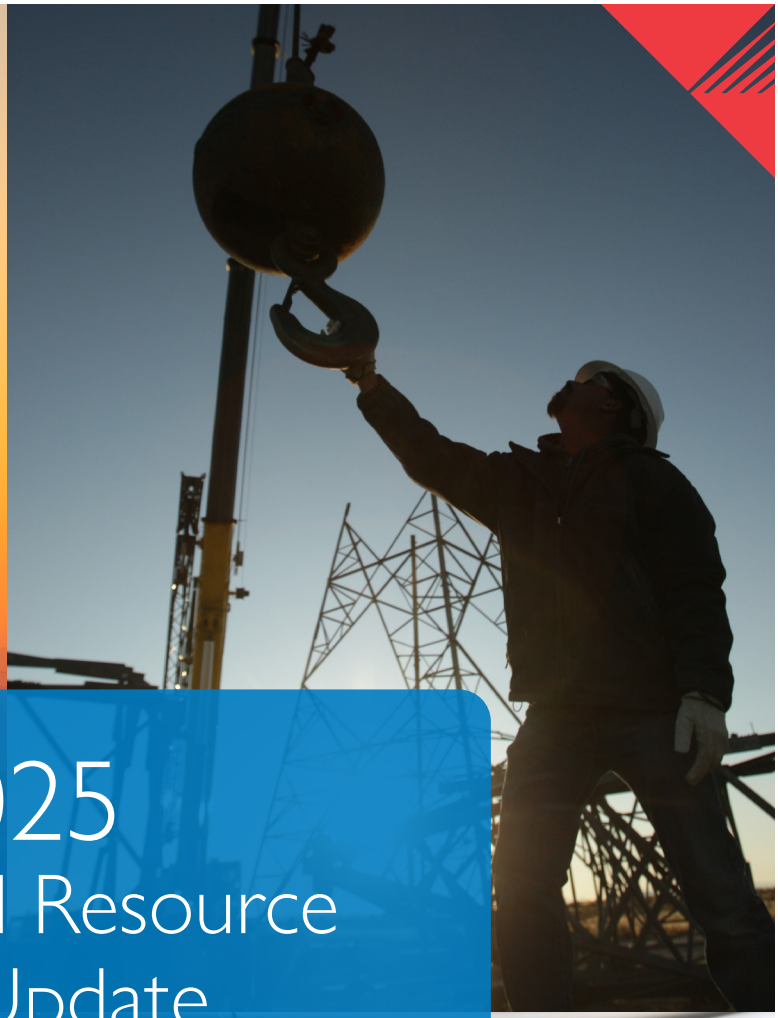

2025 Integrated Resource Plan Update

March 31, 2026

PacifiCorp

This 2025 Integrated Resource Plan Update is based upon the best available information at the time of preparation. The IRP action plan status update described herein is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually.

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CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp submitted its 2025 Integrated Resource Plan (IRP) on March 31, 2025. This 2025 Update summarizes resource planning and procurement activities since that filing, provides updated load-and-resource balance and portfolio information, and reports on action plan progress. It also offers an opportunity for stakeholder and regulatory input to inform the next IRP cycle already underway.[1]

The 2025 IRP and this Update are planning documents which embrace flexibility, not fixed resource plans or commitments. IRPs are intended to promote transparency and inform procurement decisions by evaluating multiple scenarios based on economic and policy assumptions. The 2025 IRP and this Update are forecasts driven by the best available information at a point in time. These planning processes are part of a larger regulatory process that drive actual procurement decisions, including but not limited to, cost recovery, compliance obligations and ever-changing state and Federal mandates.

Changes in this Update are largely driven by the July 4, 2025, repeal of major portions of the Inflation Reduction Act (IRA). The repeal was enacted through the H.R.1 – the One Big Beautiful Bill Act (OBBBA), which, significantly, phases out or eliminates highly impactful tax benefits, primarily for renewable solar and wind generation resources.

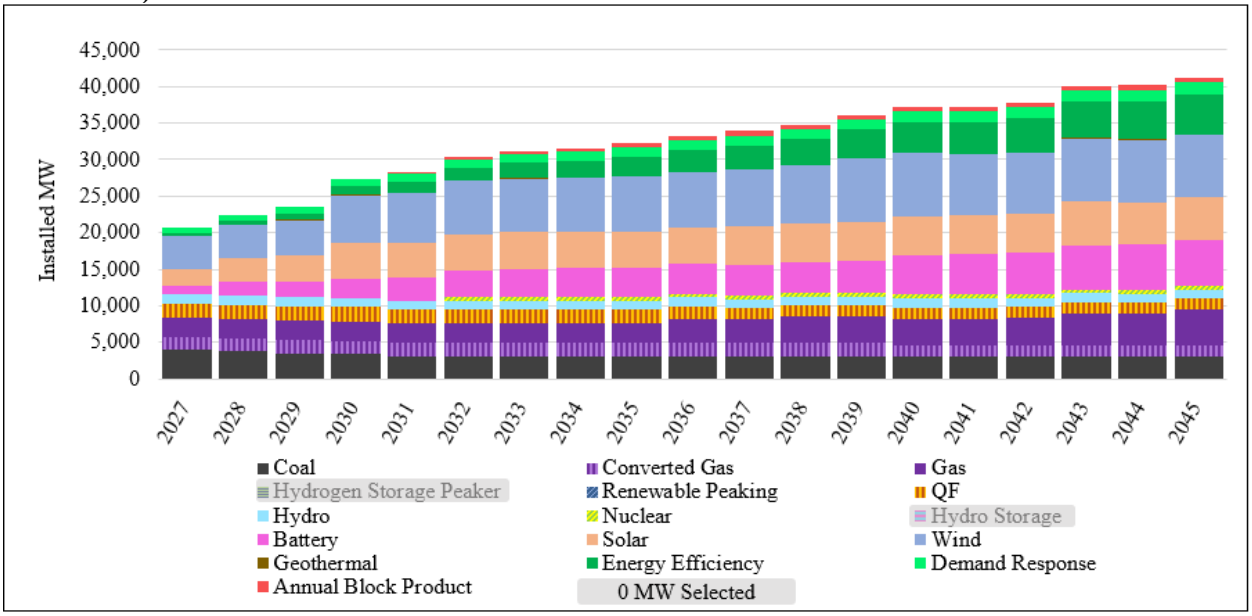
2025 IRP Update Preferred Portfolio Highlights

PacifiCorp's selection of the 2025 IRP Update preferred portfolio is supported by comprehensive data analysis, described in the chapters that follow. Figure 1.1 shows that PacifiCorp's 2025 IRP Update preferred portfolio continues to include substantial new renewables facilitated by incremental transmission investments, along with demand-side management (DSM) resources, significant storage resources, advanced nuclear development,[2] and dispatchable peaking resources. A more detailed summary of preferred portfolio resources by resource type is presented later in this section.

[1] The 2027 IRP public input meeting series has been advanced by three additional months to expand the timeline and opportunities for public feedback and to meet new regulatory requirements. This has in turn provided the opportunity for the 2027 IRP public input series to serve as a forum for discussion the 2025 IRP Update without unduly increasing regulatory burdens.

[2] The Kemmerer Unit 1 project, formerly referred to as the Natrium™ Demonstration project.

Figure 1.1 – 2025 IRP Update Integrated Portfolio Selections (Existing and Planned Resources)[1]



[1] "Coal" includes both minority and majority owned coal resources, including Jim Bridger Units 3 and 4 with CCS. "Coal" does not include coal resources converted to gas. Coal resources converted to gas are categorized under "Converted Gas" and only show at retirement, as the conversion does not increase the installed capacity of the resource. "Gas" includes only existing gas resources. "Nuclear" includes only the Kemmerer Unit 1 advanced nuclear project.

Transmission Upgrades

In the Draft 2025 IRP Update, many transmission upgrades and the accompanying resources reflect results of PacifiCorp's generator interconnection cluster study process for evaluating proposed resource additions. Transmission expansion projects can include development of new segments and exploration of new routes that have connections to other areas. Table 1.1 summarizes the new transmission paths selected to facilitate new generation resources identified as part of the 2025 IRP Update preferred portfolio.

In addition to providing increased interconnection capacity, transmission upgrades are also expected to allow for increased transfer capability between different areas of PacifiCorp's system. The 2025 IRP Update preferred portfolio includes the following transmission upgrades. Note that modeling for the 2025 IRP Update allowed for partial selection of lines.

Table 1.1 – 2025 IRP Update Transmission Selections

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2028	B2H	818	300	0	-	100%	Hemingway	Boardman
	B2H - Idaho Power Asset Transfer	600	300	0	-	100%	Borah	Hemingway
	B2H - IPC PTP Eastbound	200	200	0	-	100%	Walla Walla	Borah
	B2H-Enabled BPA Central OR Load Service	0	340	0	-	100%	n/a	n/a
	Serial queue: Central Oregon	0	0	152	4	100%	n/a	n/a
	Utah South - Wasatch Front: Spanish Fork - Mercer 345 kV	300	300	300	138	100%	Utah South	Wasatch Front
2029	Ben Lomond Upgrades	433	433	433	61	100%	NUT	Wasatch Front
	Cluster 1 Area 11: Willamette Valley	0	0	199	14	100%	n/a	n/a
	Serial/Cluster 1/2: Yakima	0	0	123	13	20%	n/a	n/a
2030	Cluster 1 Area 14: Summer Lake	400	400	400	115	100%	Summer Lake	Hemingway
	Cluster 2 Area 23: Willamette Valley	0	0	393	2	100%	n/a	n/a
	Serial/Cluster 1/2: Yakima	0	0	69	7	11%	n/a	n/a
2035	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	78	59	15%	n/a	n/a
2036	Utah South - Wasatch Front: Huntington - Clover 345 kV	800	800	800	277	100%	Utah South	Wasatch Front
2037	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	117	92	23%	n/a	n/a
	Goshen - Blackfoot 161 kV	75	75	42	16	100%	Goshen	Wasatch Front
2039	Cluster 1/2/3: Walla Walla	0	0	71	75	18%	n/a	n/a
	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	450	450	450	481	100%	Willamette Valley	Central OR
2043	Serial through Cluster 1 Area 13: Southern Oregon	0	0	54	13	23%	n/a	n/a
2045	Cluster 2 Area 6: Goshen	150	150	359	145	100%	Goshen	NUT
Grand Total		**4,226**	**3,748**	**4,041**	**1,510**			

Preferred Portfolio Resources

Resource selections in the updated preferred portfolio differ from those in the 2025 IRP preferred portfolio, driven by changes to model inputs and assumptions detailed in Chapter 6. Table 1.2 presents the breakout of resources by technology type, comparing the update to the full IRP.

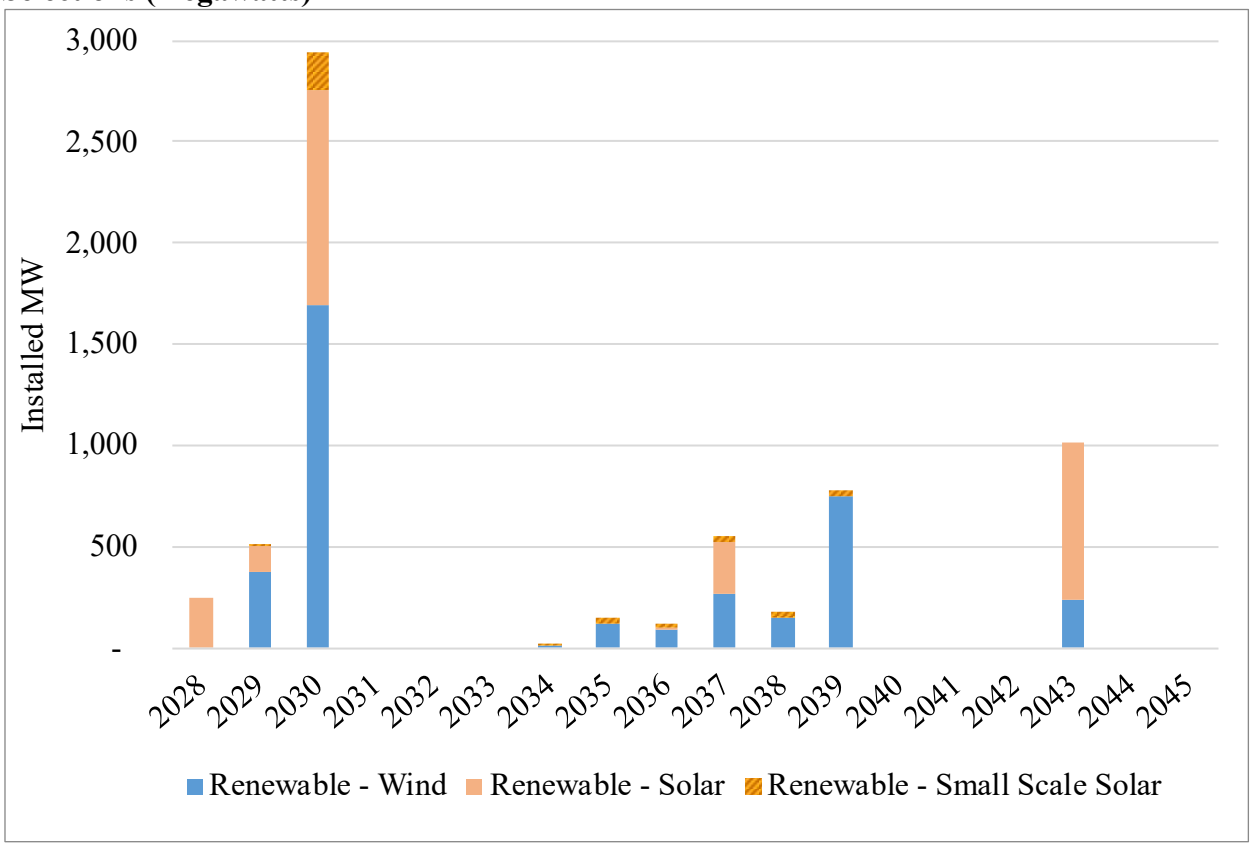
Table 1.2 – Resource Technology Type Comparison of the 2025 IRP Update to the 2025 IRP (megawatts)

Summary Portfolio Capacity by Resource Type and Year, Installed MW																				
	Installed Capacity, MW																			
Resource	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																				
Gas - CCCT																				
25 IRP Update	-	-	-	-	-	-	-	-	19	525	-	364	-	-	-	-	263	-	199	1,370
25 IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking																				
25 IRP Update	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	50	394	-	403	853
25 IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear																				
25 IRP Update	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
25 IRP	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking																				
25 IRP Update	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	20
25 IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
DSM - Energy Efficiency																				
25 IRP Update	213	224	235	269	346	329	276	308	306	315	278	305	284	265	272	293	264	207	164	5,153
25 IRP	209	220	239	261	329	291	299	295	299	315	347	314	293	300	303	315	238	205	182	5,254
DSM - Demand Response																				
25 IRP Update	2	28	182	112	22	42	32	34	33	27	5	71	34	33	51	32	25	51	215	1,031
25 IRP	-	63	21	120	99	5	1	3	3	21	112	18	5	24	61	106	29	26	52	769
Renewable - Wind																				
25 IRP Update	-	-	366	1,697	-	-	-	11	124	93	268	148	755	-	-	-	243	-	-	3,705
25 IRP	-	21	794	1,452	344	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,782
Renewable - Utility Solar																				
25 IRP Update	-	255	125	1,058	-	-	-	-	-	6	259	-	-	-	-	-	774	-	-	2,477
25 IRP	-	222	180	1,690	849	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,765
Renewable - Small Scale Solar																				
25 IRP Update	-	-	13	184	-	-	-	18	26	27	29	32	25	-	-	-	-	-	-	354
25 IRP	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
Renewable - Geothermal																				
25 IRP Update	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25 IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (< 8 hour)																				
25 IRP Update	-	715	102	548	228	154	152	57	17	55	86	9	244	1,033	129	200	298	127	-	4,154
25 IRP	-	1,146	242	296	-	119	39	210	20	47	-	175	67	113	67	713	5	459	733	4,451
Renewable - Battery (24+ hour)																				
25 IRP Update	-	-	-	4	54	227	46	-	19	-	-	-	3	-	-	-	11	16	143	523
25 IRP	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	319	402	197	358	3,073
Annual Block Product																				
25 IRP Update	-	-	-	-	212	208	345	457	640	640	640	640	640	640	640	640	640	640	640	516
25 IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Proxy Resource Technologies

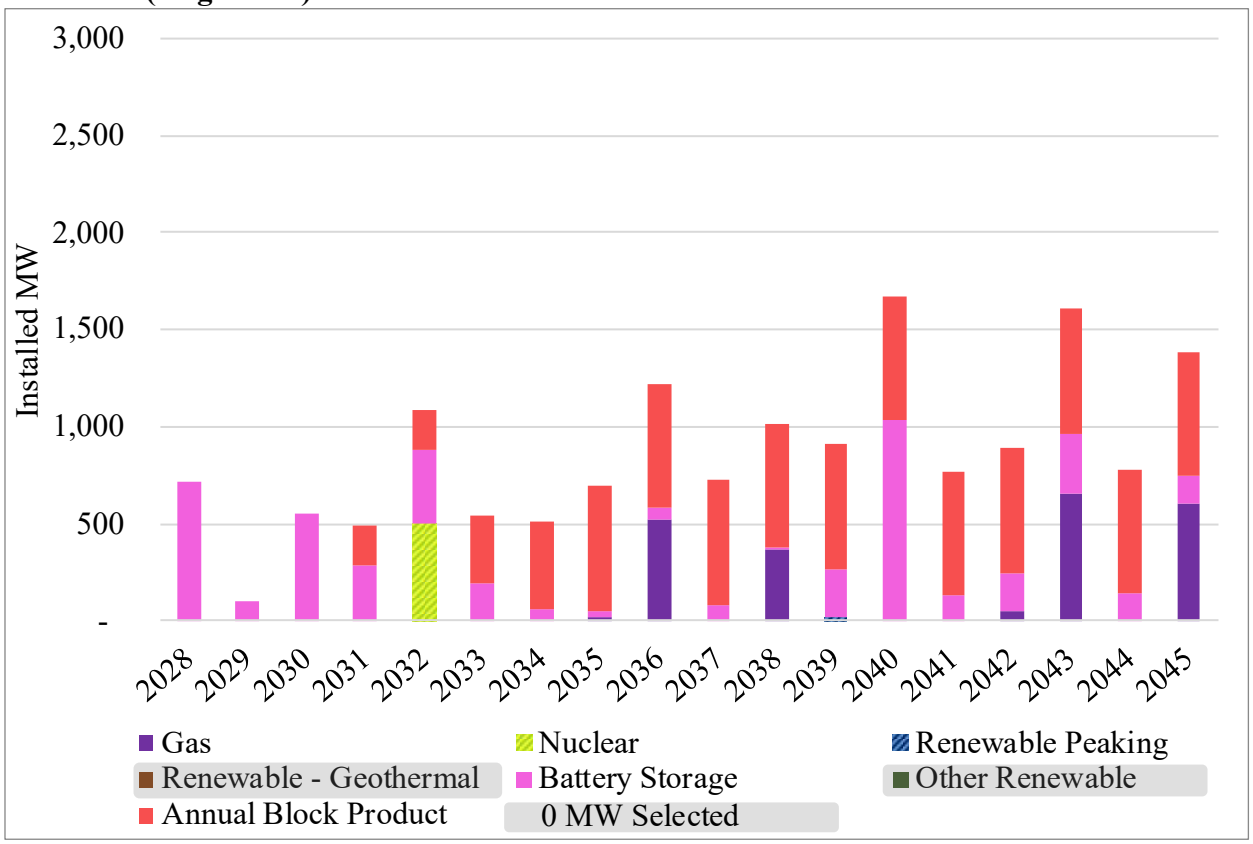
The 2025 IRP Update preferred portfolio is diverse, recommending a range of renewable, storage, nuclear and natural gas resources.

Figure 1.2 – 2025 IRP Update Preferred Portfolio Incremental Proxy Energy Resource Selections (megawatts)



The 2025 IRP Update preferred portfolio includes significant renewable energy resource selections including 3,705 MW of proxy wind, 2,477 MW of proxy utility scale solar and 354 MW of small-scale solar by the end of 2045.

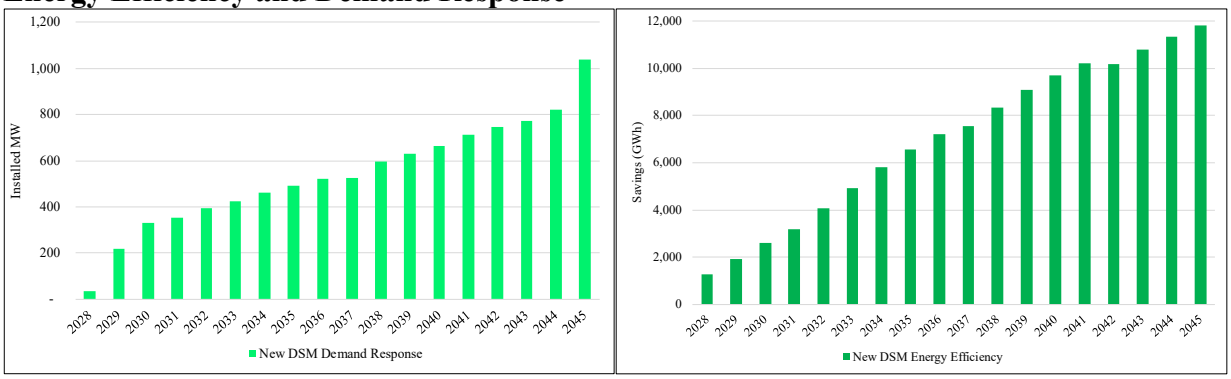
Figure 1.3 – 2025 IRP Update Preferred Portfolio Incremental Proxy Capacity Resource Selections (megawatts)[3]



In addition to significant renewable energy resource selections, the 2025 IRP Update preferred portfolio also selects significant capacity resources including 1,370 MW of proxy combined cycle gas turbines, 853 MW of proxy frame gas turbines, 4,154 MW of proxy 4-hour lithium-ion battery storage and 523 MW of proxy 100-hour iron-air battery storage by the end of 2045. The 2025 IRP Update preferred portfolio also selects proxy renewable peaking, Kemmerer Unit 1 and annual block product purchases.

[3] The "annual block product" resource option represents an annual capacity purchase available for selection in 25 MW increments in every year of the study horizon from 2030 onward. Up to 500 MW per year are available in both Mid-C and Wyoming East. Unlike other resource options shown in this chart which have technical lives that extend well beyond one year, the annual block product has a technical life of one year, meaning that the resource "retires" at the end of each year. This means that the only annual block product included in any specific year is the quantity of block product that was selected in that specific year.

Figure 1.4 – 2025 IRP Update Preferred Portfolio Cumulative Proxy Energy Efficiency and Demand Response

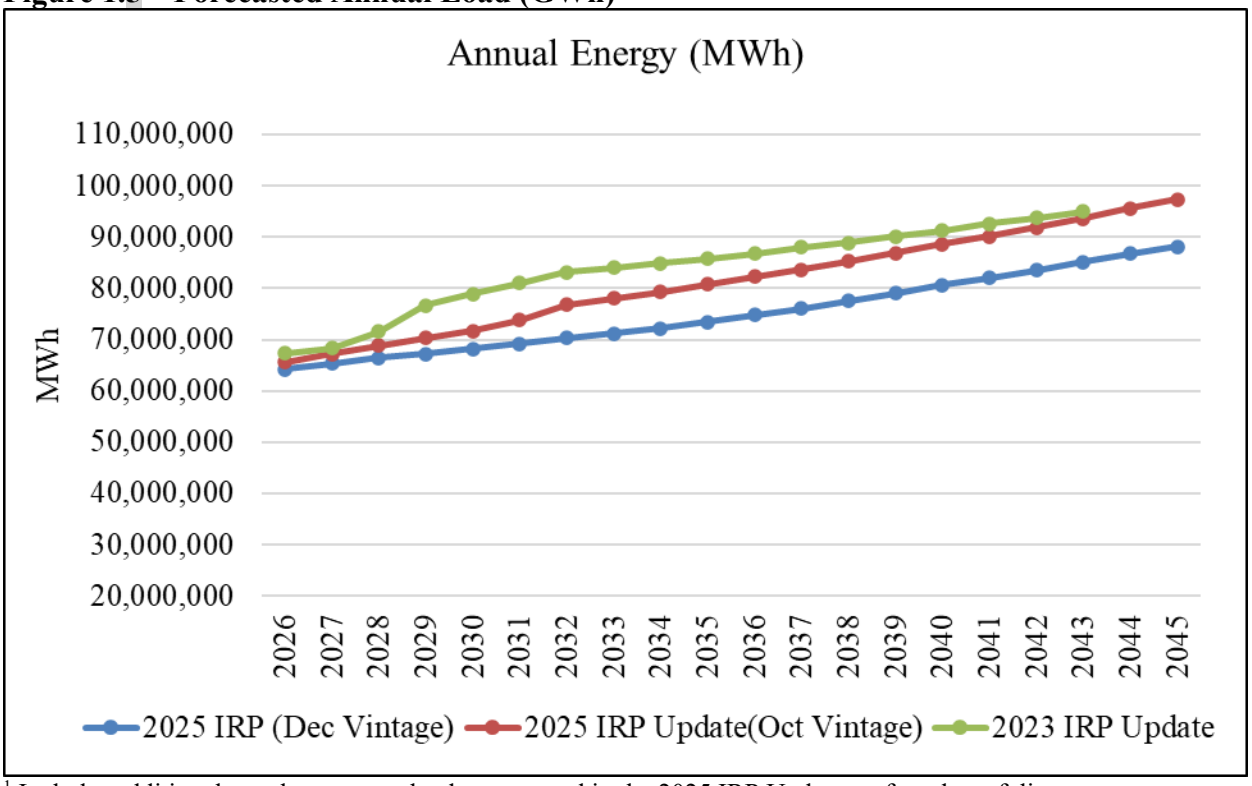


DSM resources continue to play a key role in PacifiCorp's resource mix. The 2025 IRP Update preferred portfolio includes 2,612 gigawatt-hours of cumulative energy efficiency savings by the end of 2030, 9,711 gigawatt-hours by the end of 2040 and 11,811 gigawatt-hours by the end of 2045. The Update preferred portfolio also includes 324 megawatts of new demand response capacity by the end of 2030, and 657 megawatts by the end of 2040 and 1,031 megawatts by the end of 2045.

Load Forecast

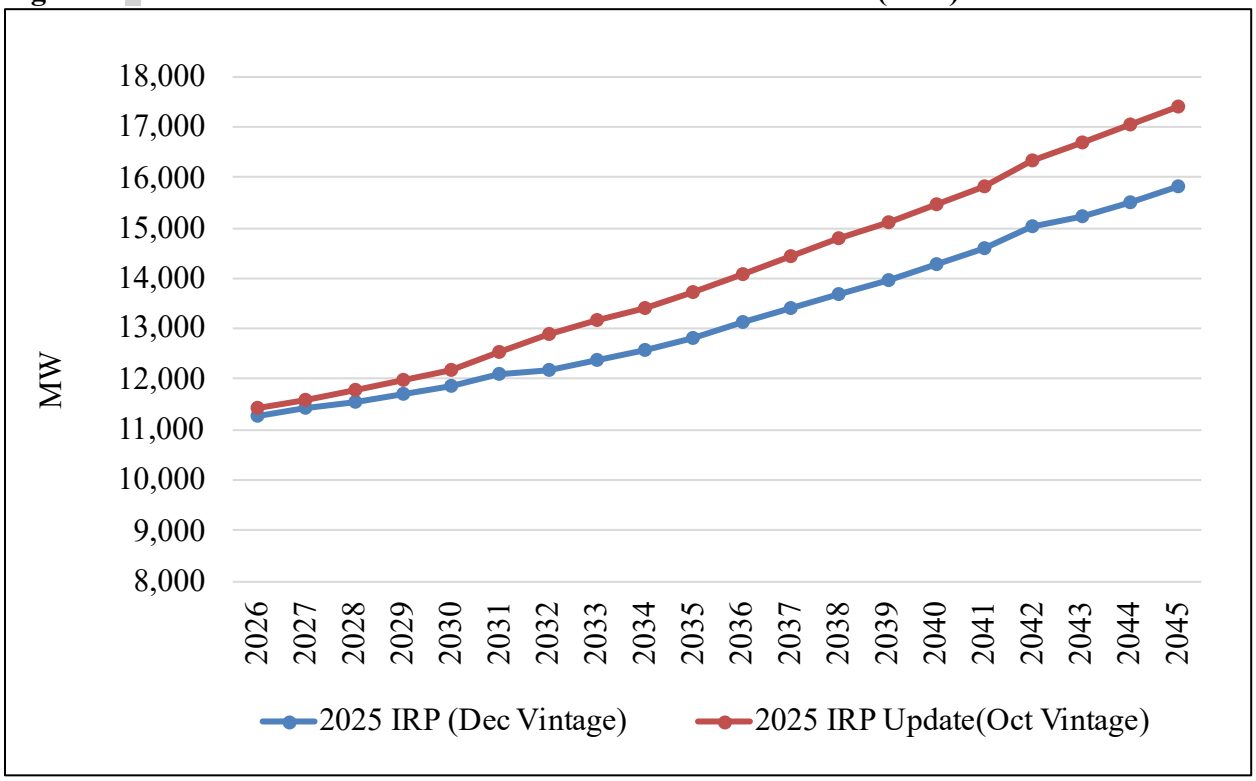
The 2025 Integrated Resource Plan (IRP) Update relies on PacifiCorp's October 2025 load forecast. Figure 1.5 compares PacifiCorp's most recent load forecast to the forecast used for the 2025 IRP and the 2023 IRP Update. Figure 1.6 compares PacifiCorp's most recent coincidence system peak load forecast to the forecast used for the 2025 IRP. Considering that PacifiCorp analyzes incremental energy efficiency and direct-load control programs as demand-side resource options in its IRP, both figures exclude incremental energy efficiency savings and direct-load control capacity included in the updated resource portfolio.

Figure 1.5 – Forecasted Annual Load (GWh)[1]



[1] Includes additional new large-meter load represented in the 2025 IRP Update preferred portfolio.

Figure 1.6 – Forecasted Annual Summer Coincident Peak Load (MW)[1]

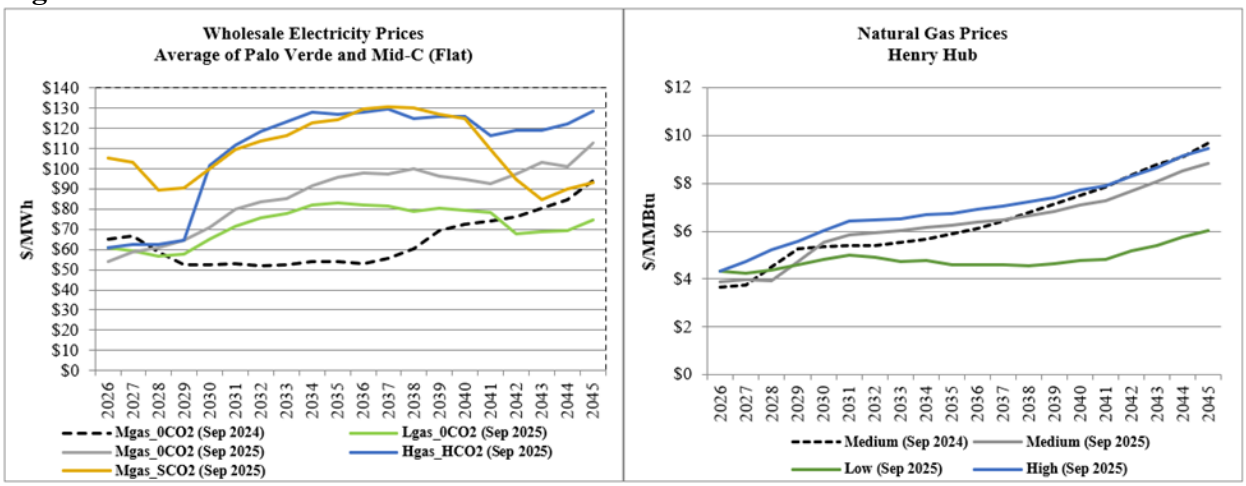


[1] Includes additional new large-meter load represented in the 2025 IRP Update preferred portfolio.

Wholesale Power Market Prices and Market Activity

Figure 1.7 illustrates the electricity and natural gas price forecasts used in the 2025 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts.

Figure 1.7 – Power and Natural Gas Price Forecasts



Market Activity

As in the 2025 IRP, PacifiCorp allowed economic purchases enabled by hourly transmission availability throughout the modeling horizon, except for certain key hours.[4] During key hours on the top five load days in each month PacifiCorp allowed zero hourly economic purchases. Hourly economic transactions do not count towards resource adequacy requirements.

Responsive to stakeholder feedback, PacifiCorp allowed block market purchases to count towards firm capacity requirements in the 2025 IRP Update. 500 megawatts of block purchases were available each at Mid-C and Wyoming East beginning in 2030. These block purchases generate a flat amount of energy in every hour during July and December, as these are the respective summer and winter months in which capacity requirements are evaluated during portfolio selection. In actual operations market purchases could also be required in additional months during the summer and winter seasons and would vary throughout each year. For additional information on block market purchases, refer to Chapter 5 "Resource Options".

The figures below present only hourly economic purchases for energy selected in the ST model. While the block purchases described above also help to meet energy requirements, block purchases have been omitted from the figures below as these products were treated on a comparable basis to other proxy resource options and were selected in the LT model to meet both energy and capacity requirements. This results in a slightly under-stated view of the total energy purchases presented in the figures below for the 2025 IRP Update as the energy benefit of block purchases is not shown.

Figure 1.8 – 2025 IRP Update Preferred Portfolio Summer Market Purchases[5,6]

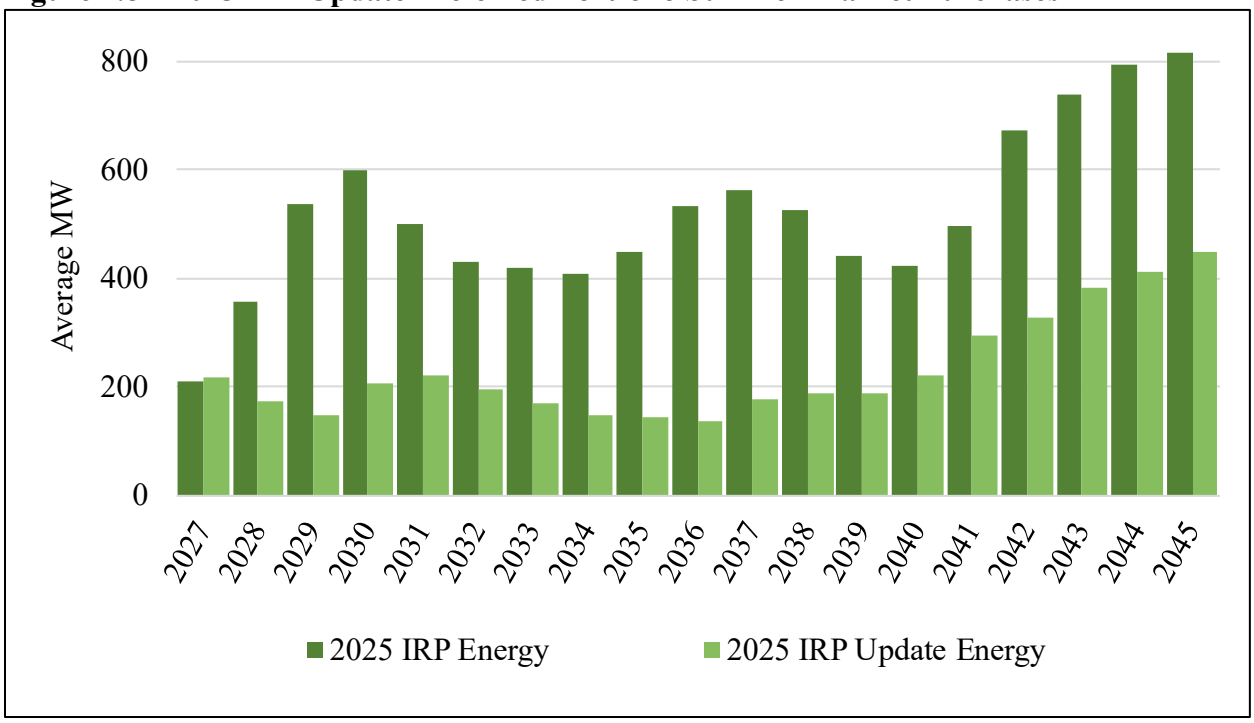
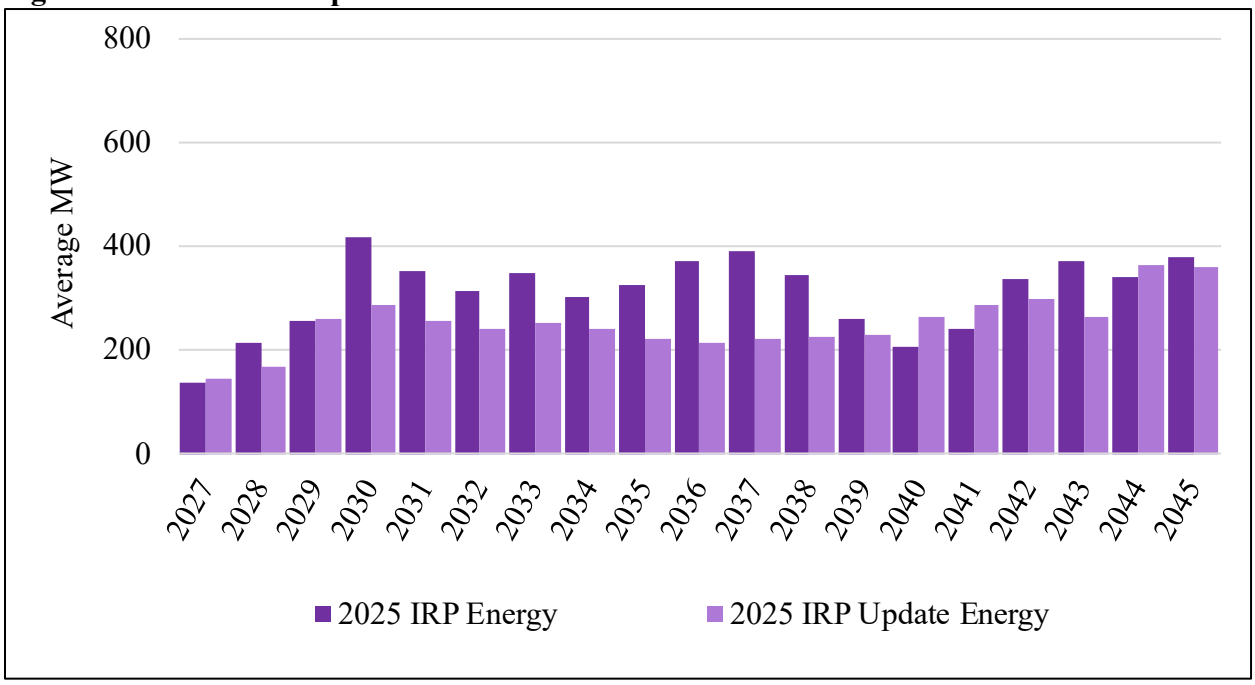


Figure 1.9 – 2025 IRP Update Preferred Portfolio Winter Market Purchases[6,7]



[5] "Summer Market Purchases" includes purchases from June through September.
[6] This figure uses short-term (ST) model results. For market data, it is appropriate to use ST model results because the ST model is run with an hourly granularity which more accurately represents the energy needed to meet load obligations compared to the less granular LT capacity expansion model.
[7] "Winter Market Purchases" includes purchases from December and January.

Coal and Gas Retirements/Gas Conversions

Coal resources have been, and remain, a valuable resource in PacifiCorp's resource portfolio, fulfilling roles as base load resources, and as dispatchable support for newer renewable and storage technologies. The operating capabilities of these facilities have adapted to the planning environment, and current indications point to changing roles in the future. PacifiCorp has been able to lower operating minimums and optimize coal dispatch through the Energy Imbalance Market (EIM). This in turn has enabled the company to both reduce fuel consumption and associated costs and emissions by increasingly buying low-cost, zero-emissions renewable energy from market participants across the West, accessible by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. EPA's approval of Wyoming's ozone plan and the stay of EPA's disapproval of Utah's ozone plan resulted in fewer restrictions on coal-fired operation than were projected in the recent past.

Table 1.3 compares coal unit dispositions side-by-side between the 2025 IRP and the 2025 IRP Update. Of the 22 resources listed, six report differences in conversions or retirements recommended by updated modeling.

Table 1.3 – Coal Unit Retirements in the 2025 IRP and 2025 IRP Update

Coal		
Unit	2025 IRP Retirement Year (1/1/XX)	2025 IRP Update Retirement Year (1/1/XX)
	As Selected	As Selected
Colstrip 3 (1)	2030	2030
Colstrip 4	2030	2030
Craig 1	2026	2026
Craig 2	2029	2029
DaveJohnston 1 (2)	2045+	2040
DaveJohnston 2 (3)	2045+	2044
DaveJohnston 3	2028	2028
DaveJohnston 4	2045+	2045+
Hayden 1	2029	2029
Hayden 2	2028	2028
Hunter 1	2045+	2045+
Hunter 2	2045+	2045+
Hunter 3	2045+	2045+
Huntington 1	2045+	2045+
Huntington 2	2045+	2045+
JimBridger 1	2045+	2045+
JimBridger 2	2045+	2045+
JimBridger 3 (4)	2043	2045+
JimBridger 4 (5)	2043	2045+
Naughton 1 (6)	2043	2040
Naughton 2	2045+	2045+
Wyodak	2045+	2045+

No Change
Change from 2025 IRP

Comparing the 2025 IRP Update to the 2025 IRP, there are six notable changes, keyed to the table entries above:

1. In the 2025 IRP, PacifiCorp modeled its share of Colstrip 3 as expiring at the beginning of 2026, to be replaced by an increase in PacifiCorp's share of Colstrip 4. In the 2025 IRP Update, PacifiCorp maintains a flat share of Colstrip 3 and Colstrip 4 until the retirement of both shares at the beginning of 2030. PacifiCorp's combined share of Colstrip 3 and Colstrip 4 is the same in the 2025 IRP Update as it was in the 2025 IRP.
2. In the 2025 IRP, Dave Johnston 1 was selected for gas conversion in 2029, and this gas conversion continued to operate throughout the horizon. In the 2025 IRP Update, Dave Johnston 1 is still selected for gas conversion in 2029, but the gas converted unit was selected for retirement at the beginning of 2040. This is viewed as acceptable given the

relatively low cost of gas conversion. The Dave Johnston sensitivity study selects continued coal-fired operation of Dave Johnston throughout the horizon.

3. In the 2025 IRP, Dave Johnston 2 was selected for gas conversion in 2029, and this gas conversion continued to operate throughout the horizon. In the 2025 IRP Update, Dave Johnston 2 is still selected for gas conversion in 2029, but the gas converted unit was selected for retirement at the beginning of 2044. This is viewed as acceptable given the relatively low cost of gas conversion.
4. In the 2025 IRP, Jim Bridger Unit 3 installed CCS in 2030 and retired at the beginning of 2042. In the 2025 IRP Update, Jim Bridger 3 installs CCS in 2031 and continues to operate through the end of the modeling horizon.
5. In the 2025 IRP, Jim Bridger Unit 4 installed CCS in 2030 and retired at the beginning of 2042. In the 2025 IRP Update, Jim Bridger 4 installs CCS in 2031 and continues to operate through the end of the modeling horizon.
6. In the 2025 IRP, Naughton 1 underwent gas conversion in 2026 and continued to operate until the beginning of 2043. In the 2025 IRP Update, Naughton 1 starts the modeling horizon as a gas-converted unit and continues to operate until it is selected for retirement at the beginning of 2040.

Resource Procurement and Requests for Proposals

PacifiCorp issued a Washington situs RFP to market on September 2, 2025. Final bids were received by October 7, 2025. PacifiCorp has completed bid evaluation and is in the process of contracting shortlisted bids. On October 13, 2025, PacifiCorp issued an Oregon situs RFP to market. PacifiCorp received final bids by November 18, 2025. PacifiCorp expects to complete bid evaluations in May 2026 and to finalize contracts afterwards. The RFP schedules for both Oregon and Washington are subject to change.

Carbon Dioxide Emissions

The 2025 IRP Update preferred portfolio reflects PacifiCorp's on-going efforts to provide valuable energy solutions for all its customers and comply with state-specific carbon dioxide (CO_2) and other carbon dioxide equivalent (CO_2e) emissions reductions requirements.

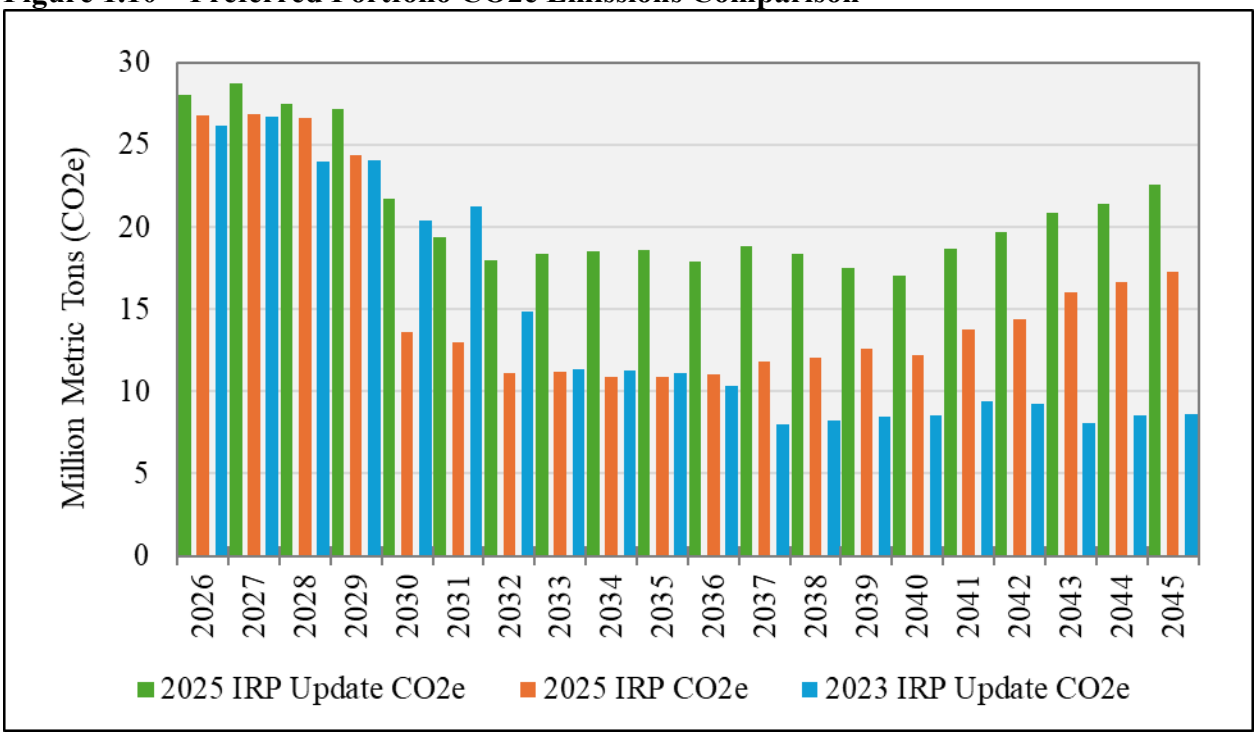
PacifiCorp's total system emissions have been declining and will continue to decline until 2030 largely due to participation in the EIM and a commitment to CAISO's Extended Day-Ahead Market (EDAM), which reduces customer costs and maximizes use of non-emitting renewable resources that have no fuel cost and may generate tax credits.

The chart below in Figure 1.10 compares projected annual CO_2e emissions between the 2025 IRP Update and 2025 IRP preferred portfolios. In this graph, emissions are assigned to market purchases at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour.

The 2025 IRP Update preferred portfolio shows a continued downward trajectory in emissions over the near term; however, emissions are higher than projected in the 2025 IRP starting in 2027. Removal of the Ozone Transport Rule, which limits summer generation from gas and coal-fueled resources, is a significant driver. Further, over the longer-term the load forecast in the 2025 IRP

Update is higher than in the 2025 IRP. Finally, the 2025 IRP Update accounts for the federal phase out of production tax credits for renewable electricity generation.

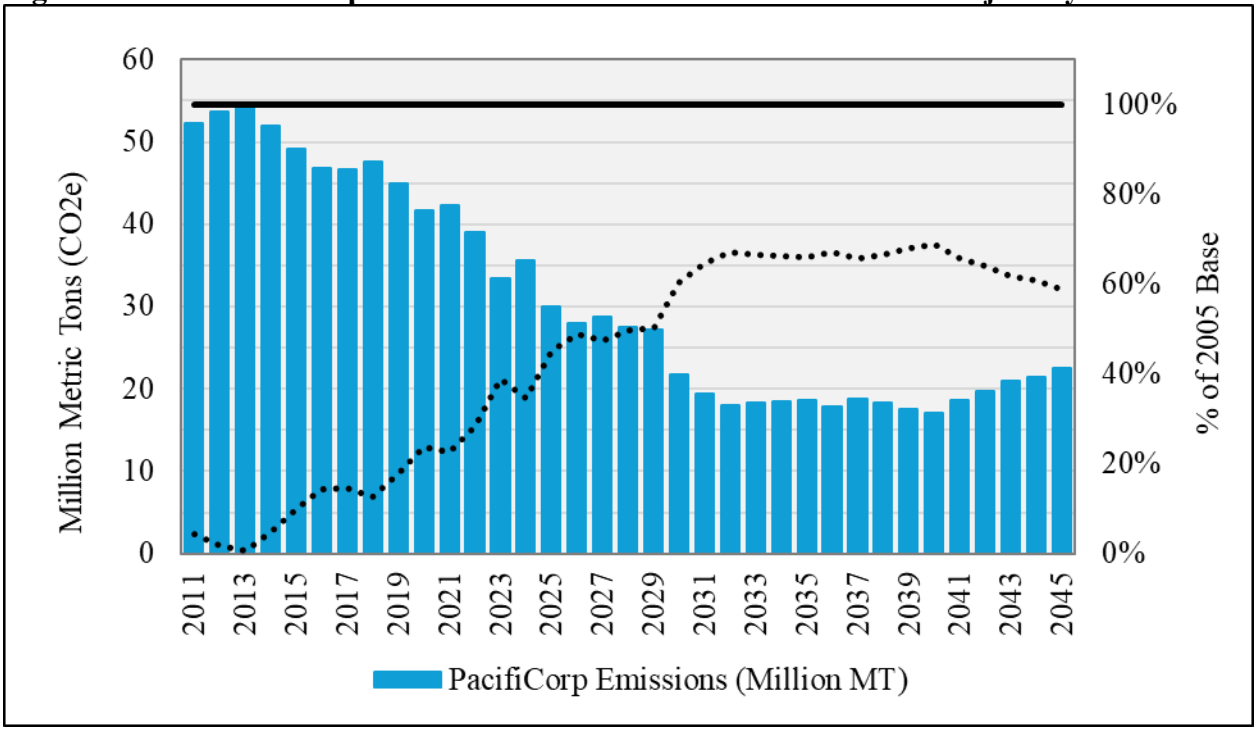
Figure 1.10 – Preferred Portfolio CO2e Emissions Comparison*



* PacifiCorp CO_2 equivalent emissions trajectory reflects those from the 2025 IRP Update preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/megawatt-hour). Emissions from sales are not removed.

Figure 1.11 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2045. This graph demonstrates that relative to a 2005 baseline, of 54.6 million metric tons, system CO_2e emissions are down 44% in 2025, 68% in 2030, 66% in 2035, 68% in 2040, and 60% in 2045.

Figure 1.11 – 2025 IRP Update Preferred Portfolio CO2e Emissions Trajectory*



* PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2023 from owned facilities, specified sources and unspecified sources. 2024 emissions were from the 2023 IRP Update forecasted values. 2025 emissions were not forecasted in the 2025 IRP Update and therefore reflect the forecast from the 2025 IRP Update. From 2026 through the end of the 20-year planning period in 2045, emissions reflect those from the 2025 IRP Update preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectory.

Renewable Portfolio Standards

Figure 1.12, shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the 2025 IRP Update preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

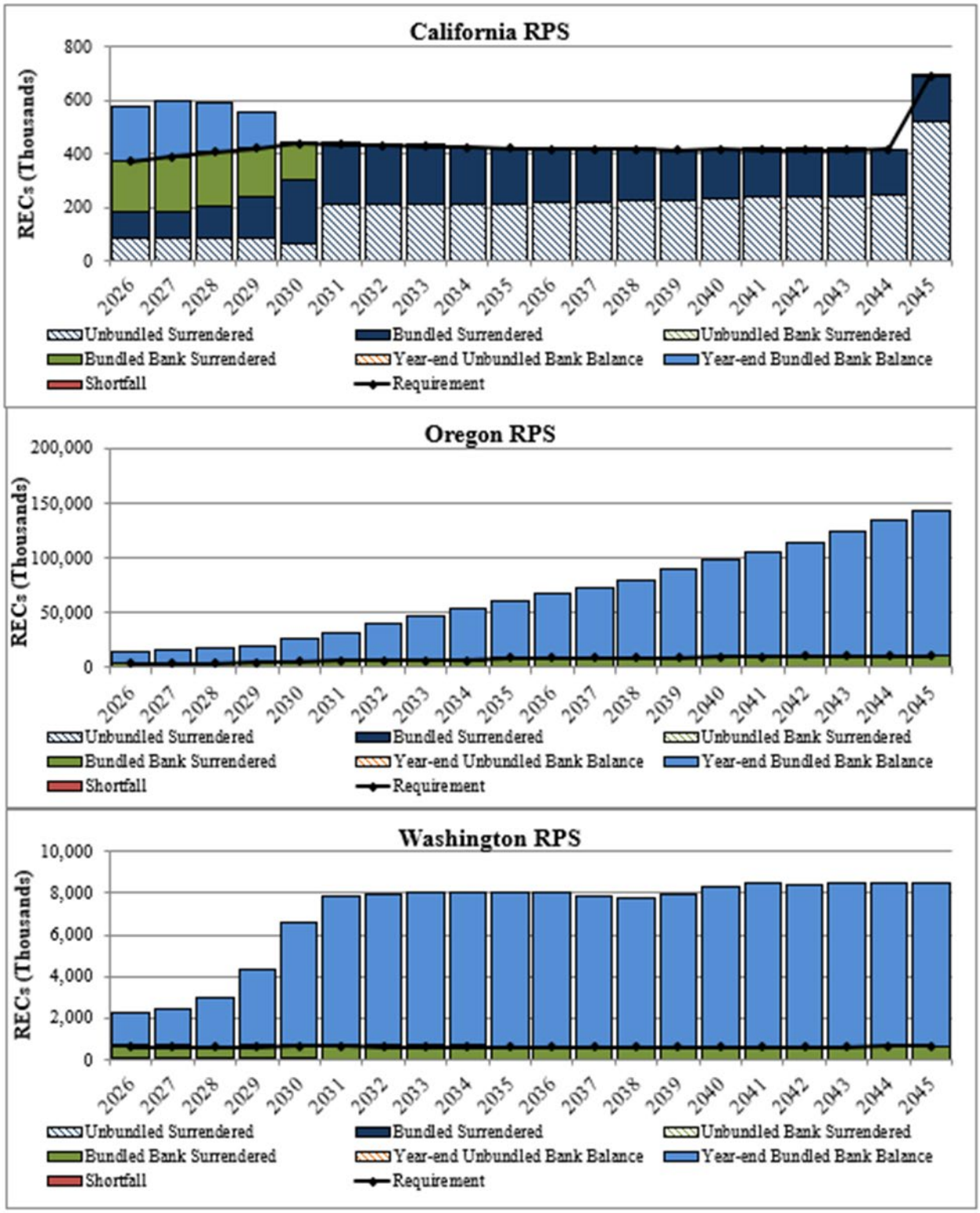
The California RPS compliance position will be met through year 2030 with owned and contracted renewable resources, as well as renewable energy credit (REC) purchases. Beyond 2030, the company may need to purchase approximately 200,000 unbundled RECs per year on a long-term contract to meet the RPS target of 60% in years where a shortfall is projected. Alternatively, PacifiCorp may consider the acquisition of new renewable resources to meet California's RPS. In 2045, California's RPS target increases to 100%.

Oregon RPS compliance is achieved through 2045 with the addition of new renewable resources in the 2025 IRP Update preferred portfolio.

Under PacifiCorp's 2026 Protocol Washington's RPS position is improved by receiving a system share of renewable resources across PacifiCorp's system, and there are no anticipated shortfalls.

While not shown in Figure 1.12, PacifiCorp meets the Utah 2025 state target to supply 20% of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources.

Figure 1.12 – Annual State RPS Compliance Forecast



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CHAPTER 2 – INTRODUCTION

The 2025 Integrated Resource Plan (IRP) Update describes resource planning activities following the filing of the 2025 IRP on March 31, 2025, and continues the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. As the owner of the IRP Update and its action plan, all policy judgments and decisions concerning the IRP Update are made by PacifiCorp considering its obligations to its customers, regulators, and shareholders.

PacifiCorp's 2025 IRP Update preferred portfolio reflects updates to load, existing resources, signed contracts, transmission options, and modeling. The 2025 IRP Update also includes variant analysis for carbon capture and nuclear technologies, a range of future market and environmental policy environments, and updated analysis of specific elements of state-specific planning, such as Oregon Clean Energy Plan and Washington's Clean Energy Implementation Plan.

PacifiCorp's selection of the 2025 IRP Update preferred portfolio is supported by comprehensive data analysis described in the chapters that follow. Chapter 3 describes the current planning environment, load updates, resource updates, state and federal policy updates, and transmission upgrades. Chapter 4 provides updated load-and-resource balance information. Chapter 5 describes changes to key resource inputs and assumptions relative to those used for the 2025 IRP. Chapter 6 presents the modeling methodology, while Chapter 7 presents model outcomes including the preferred portfolio, variant study results, and additional price-policy studies.

Chapter 7 also confirms that PacifiCorp's 2025 IRP Update preferred portfolio continues to include substantial new renewables facilitated by incremental transmission investments, along with demand-side management resources, energy storage, peaking resources, and the Kemmerer Unit 1 advanced nuclear project. In addition to these resource selections, the Update preferred portfolio includes substantial new gas resources, a notable change from the 2025 IRP preferred portfolio, driven primarily by changes in federal legislation.

Chapter 8 provides an analysis of sensitivities that serve as bookends and "what-if" scenarios contributing to the evaluation of the alternative path analysis and portfolio robustness analysis presented in Chapters 7 and 9.

Chapter 9 presents PacifiCorp's Alternative Path analysis, which previously resided with the Action Plan, but has been significantly expanded and given its own chapter.

A status update on the 2025 IRP Action Plan is provided in Chapter 10.

In addition to the main body of information provided in Chapters 1 through 10, the 2025 IRP Update also provides several detailed appendices to illuminate specific topics. Appendix A presents additional load forecast details. While the 2025 IRP Update is not subject to specific requirements or regulation in most jurisdictions, Appendix B nonetheless provides a summary of key regulatory elements. Appendix C details information regarding supply-side resource inputs given in summary for Chapter 5. Appendices D, E and F update key information relevant to the Oregon, Washington, and California jurisdictions. Appendix G details information regarding stakeholder feedback, including the role of the 2027 IRP public meeting series in this update and

a summary of new stakeholder feedback for the 2025 IRP received since the filing on March 31, 2025. Finally, Appendix Z provides a listing of acronyms and relevant definitions for PacifiCorp's IRP reporting.

CHAPTER 3 – PLANNING ENVIRONMENT

Introduction

The 2025 Integrated Resource Plan (IRP) Update reflects changes to the planning environment since the 2025 IRP was filed on March 31, 2025. PacifiCorp highlights these changes relative to 2025 IRP conditions and assumptions impacting the planning horizon through 2045.

The primary driver of change in the 2025 IRP Update is the July 4, 2025, repeal of major portions of the Inflation Reduction Act (IRA). The repeal was enacted through the H.R.1 – the One Big Beautiful Bill Act (OBBBA). Passage of the OBBBA is consistent with PacifiCorp's experience over several long-term planning cycles in which there is substantial volatility in the realm of policy, with material changes occurring with increasing frequency.

This chapter details important changes and milestones in the planning environment, including key federal and state policy updates.

Federal Policy Update

One Big Beautiful Bill Act

On July 4, 2025, President Trump signed the OBBBA which alters federal taxes, credits, and deductions, some of which are relevant to PacifiCorp and other electric utilities.

The OBBBA accelerated the phase out of production tax credits, technology neutral tax credits and added foreign entity of concern rules for credit qualification.

- December 31, 2030, is the placed-in-service deadline for wind and solar projects that began construction by July 4, 2026.
- December 31, 2027, is the placed-in-service deadline for wind and solar projects that did not begin construction by July 4, 2026.
- December 31, 2033, is the deadline for technology neutral projects (other than wind and solar) to begin construction to qualify for any tax credits, with the placed in service deadline being December 31, 2037.
- Projects and/or taxpayers are not credit eligible if (1) the project receives "material assistance" from a "prohibited foreign entity", (2) the taxpayer is determined to be a "specified foreign entity" or "foreign-influenced entity," or (3) it is determined that foreign entities have "effective control" over the taxpayer or the projects.

Coal Leasing

- The OBBA reduces the maximum royalty rate for all federal coal leases (surface and underground) to no more than 7.0% (down from 12.5% minimum, except for underground coal mining) from the date of enactment through September 30, 2034.
- This change will primarily affect powder river basin coal, where surface mining royalties will drop from 12.5% to 7.0% through 9/30/34. There are a few deep mines on federal coal where the rate will drop from 8.0% to 7.0%.

- The OBBBA requires the Secretary of Interior to make at least 4,000,000 additional acres of federal land available with known recoverable coal resources available for lease and requires the Secretary of Interior to take the actions necessary to authorize the mining of these federal lands. This increase in supply will likely reduce the cost of coal.

Advanced Manufacturing Production Credit (45X tax credits)

- The OBBBA includes "metallurgical coal" as an "applicable critical mineral" for purposes of the advanced manufacturing production credit. The bill defines "metallurgical coal" as "coal which is suitable for use in the production of steel…" and establishes a tax credit of 2.5% of the costs incurred by the taxpayer with respect to the production of such metallurgical coal.
- The tax credit for metallurgical coal will be available for such coal produced in 2026 through 2029.
- While there are phase-out provisions in 45X for the production of other critical minerals, there is no such phase-out applicable to metallurgical coal.

Carbon Capture and Sequestration

- The OBBBA creates parity between 45Q credit levels for carbon utilization projects and those storing captured CO2 underground. Specifically, for facilities placed in service after enactment, the credit amount ($17 per metric ton) would be the same regardless of whether the taxpayer disposed of the captured carbon oxide or whether the facility undertakes use or utilization of the captured carbon oxide.
- The $17 per metric value would apply for tax years beginning in a calendar year after 2024 and before 2027 (indexed to a base year of 2026 for annual inflation adjustment).
- The budget bill would reduce the benefit to direct air capture facilities by setting a flat credit of $26 per metric ton across all project categories. Currently, these projects are eligible for a credit of $36 per metric ton for carbon oxide stored in secure geological storage and $26 per metric ton for carbon oxide used in tertiary injection or otherwise utilized.
- Under OBBBA, developers of renewable hydrogen and nuclear power, and carbon capture, can still sell their credits to third parties in order to raise capital to finance projects.
- The OBBBA does, however, make foreign entities ineligible from claiming the 45Q credit.

General Impacts on Climate Funding

- By phasing out funding to renewable energy resources, the OBBBA will likely make coal a relatively more cost-effective resource, increasing the competitiveness of coal in the electric grid.
- The bill rescinds all unobligated funding from the Inflation Reduction Act from the $20 billion Greenhouse Gas Reduction Fund. The impacted funding includes funding to green banks and financial intermediaries that would then redeliver funds to cities for climate action projects under the National Clean Investment Fund (NCIF) and Clean Communities Investment Accelerator (CCIA).
- Additionally, the OBBBA phases out tax credits for wind and solar power, which may make coal a more competitive fuel source. Previously, companies building wind and solar farms could qualify for a tax credit worth at least 30 percent of costs if they began construction before 2034. Under the new law, projects would likely need to start

construction within the next year to increase the likelihood that they will qualify from the tax benefit.

The OBBBA is also anticipated to impact demand-side resources in the future. The bill accelerated the end dates of energy credits and deductions for homes and businesses which had been a part of the Inflation Reduction Act. Specifically, the OBBBA ends the energy efficient home improvement credit (section 25C), the residential clean energy credit (section 25D), and the energy efficient commercial buildings deduction (section 179D).[1] The possible range of impacts on DSM potential are not yet clear in the data but are being evaluated as part of the Conservation Potential Assessment and the Distributed Generation Study.[2]

Federal Climate Change Legislation

Federal climate change legislation is not anticipated in the near term but remains possible in the mid- to long-term.

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

New Source Performance Standards are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare, including thermal electric generating units. After two previous iterations, in 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 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.

[1] See Internal Revenue Service web page: https://www.irs.gov/newsroom/faqs-for-modification-of-sections-25c-25d-25e-30c-30d-45l-45w-and-179d-under-public-law-119-21-139-stat-72-july-4-2025-commonly-known-as-the-one-big-beautiful-bill-obbb

[2] See Appendix G, stakeholder feedback form #14 (Utah Clean Energy)

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.

On June 11, 2025, the EPA proposed to repeal the 2024 standards. If finalized as proposed, the rule would repeal the requirements to install carbon capture and sequestration (CCS) on existing coal-fired steam generating units. The EPA proposed two paths:

1. Primary Proposal: Repeal all greenhouse gas (GHG) emissions standards for fossil fuel-fired power plants on the basis that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution; or

2. Alternative Proposal: Repeal a narrower set of requirements that includes the emission guidelines for existing fossil fuel-fired steam generating units, the carbon CCS-based standards for coal-fired steam generating units undertaking a large modification, and the CCS-based standards for new base load stationary combustion turbines.

PacifiCorp commented on the action through Berkshire Hathaway Energy. The comments supported the alternative proposal that CCS is not the best system of emission reduction (BSER) for coal-fired steam generating units. The comments also requested removal of the "phase 1" standards applicable to new and reconstructed base load fossil fuel-fired stationary combustion turbines.

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The Clean Air Act requires the EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants that have the potential of harming human health or the environment. The six pollutants are carbon monoxide, lead, ground-level ozone, nitrogen dioxide (NO_X), particulate matter (PM), and sulfur dioxide (SO_2). The standards are set at a level that protects public health with an adequate margin of safety. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area determined to contribute to the nonattainment are required to reduce emissions. If an area is determined to be out of compliance with an established NAAQS standard, the state is required to develop a state implementation plan to bring that area into compliance, and that plan must be approved by the EPA. The plan is developed so that once implemented, the NAAQS for the pollutant of concern will be achieved.

Ozone NAAQS

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 the EPA that the states used to determine downwind impacts.

On January 31, 2023, the 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. The EPA finalized disapproval of Utah's CSAPR SIP along with 18 other states and issued a partial disapproval for two additional states. The 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 the 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. PacifiCorp and other industry petitions filed a motion in the Tenth Circuit to hold in abeyance EPA's disapproval of Utah's state plan. PacifiCorp filed a motion to request that litigation be suspended while the EPA proceeds with reconsideration of its action. The court has suspended the litigation until at least February 6, 2026.

Particulate Matter (PM2.5) NAAQS

On March 6, 2024, EPA revised the primary annual PM2.5 NAAQS from 12.0 µg/m3 to 9.0 µg/m3. The EPA has not yet designated areas as attainment, nonattainment, unclassifiable/attainment, or unclassifiable under this new standard. In March 2025, the EPA announced that the agency will revisit this PM2.5 NAAQS standard. The EPA also announced that it would release guidance to increase flexibility on NAAQS implementation, reforms to New Source Review, and direction on permitting obligations.

In November 2025, the EPA approved the redesignation of the Salt Lake City, Utah and Provo, Utah nonattainment areas to attainment for the 2006 24-hour PM2.5 NAAQS.

Regional Haze

EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility, by 2064, in certain national park and wilderness areas. Many of these areas are in the western United States where PacifiCorp owns and operates several coal-fired generating units (Utah, Wyoming, Colorado, and Montana as well as Arizona, where a PacifiCorp-owned

coal unit ceased operating in 2020). The states are required to update their regional haze rule plans approximately every ten years. State implementation plans for the second planning period revisions due in August of 2022. On January 6, 2026, the EPA finalized a rule that would extend the state implementation plan due date for the third planning period from July 31, 2028, to July 31, 2031.

Utah Regional Haze

On December 2, 2024, the EPA finalized a final partial approval and partial disapproval for Utah's regional haze state implementation plan for the second planning period without simultaneously finalizing a federal implementation plan. Specifically, the EPA disapproved the long-term strategy, reasonable further progress goals, and federal land management (FLM) consultation components of the SIP. EPA's disapproval of Utah's long-term strategy is based, in part, on EPA's rejection of Utah's finding that installation of SCR or other physical NOx pollution controls for Hunter and Huntington is not necessary to achieve reasonable progress. There are no new compliance obligations for PacifiCorp at this time, as the disapprovals did not include a simultaneously finalized FIP. PacifiCorp filed a petition for reconsideration on EPA's disapproval action on January 30, 2025, and filed a petition for review in the Tenth Circuit the next day. The EPA granted PacifiCorp's petition for reconsideration on EPA's disapproval of Utah's Regional Haze state implementation plan submission for the second planning period on April 30, 2025.

Wyoming Regional Haze

Naughton – In its 2014 rule, EPA approved Wyoming's determination that BART for Units 1 and 2 was low-nitrous oxide burners (LNB) and over-fired air (OFA). The EPA also indicated support for the conversion of the Naughton Unit 3 to natural gas in lieu of retrofitting the unit with SCR and stated that it would expedite consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. Wyoming submitted its regional haze SIP amendment regarding Naughton Unit 3 to EPA on November 28, 2017. On March 7, 2017, Wyoming issued PacifiCorp a permit for Unit 3's conversion to natural gas, which allowed operation of Unit 3 on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019, as required by the permit. EPA's final rule approval of Wyoming's SIP revision for Naughton Unit 3 gas conversion was published in the Federal Register on March 21, 2019, with an effective date of April 22, 2019. Naughton Unit 3 currently operates on natural gas. Environmental groups petitioned EPA's approval of LNB/OFA as BART for Units 1 and 2 in the Tenth Circuit. On August 15, 2023, the court determined EPA properly approved Wyoming's Naughton determination and denied environmental groups' petition.

Jim Bridger – On December 30, 2022, Wyoming submitted a state-approved revised regional haze SIP requiring natural gas conversion of Jim Bridger Units 1 and 2 to EPA for approval. The SIP conversion replaces the previous requirement for SCR at the units. Wyoming also issued an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 on December 28, 2022. On August 7, 2025, EPA finalized approval of Wyoming's plan addressing the regional haze long term strategy for the first planning period at Jim Bridger. On March 9, 2023, PacifiCorp submitted a notice of compliance and request for termination of the EPA order. The conversion process is underway at the units.

Wyodak – PacifiCorp and the state of Wyoming petitioned EPA's FIP requiring SCR at Wyodak in the Tenth Circuit. PacifiCorp and other parties successfully requested a stay of EPA's final rule relating to EPA's FIP pending court resolution of the petition. PacifiCorp subsequently submitted

a request for reconsideration to the EPA and engaged in a settlement process with the EPA and Wyoming. The EPA, state of Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020. The 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, the 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 the EPA for further review in accordance with the requirements of the Clean Air Act.

Dave Johnston – On January 30, 2014, the EPA disapproved Wyoming's state implementation plan for the first planning period and promulgated a federal implementation plan. EPA's January 20, 2014, FIP action required either the installation of SCR on Dave Johnston Unit 3 or that the unit retire by the end of 2027. PacifiCorp opted not to install SCR. The EPA approved Wyoming's NOx BART determination for Dave Johnston Unit 4 of an emission limit of 0.15 lb/MMBtu (30-day rolling average). The EPA also approved Wyoming's NOx reasonable progress determinations for Dave Johnston Units 1 and 2 that no controls were necessary. PacifiCorp filed a petition for reconsideration with the EPA on EPA's federal implementation plan. While the EPA has not granted PacifiCorp's petition for reconsideration, PacifiCorp has included a sensitivity in the 2025 IRP Update that allows continued operation of Unit 3 in the event that the EPA does reconsider the shutdown requirement currently applicable to this unit.

Wyoming Regional Haze Second Planning Period – On December 2, 2024, the EPA finalized partial approval and partial disapproval of Wyoming's regional haze SIP 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. There are no new compliance obligations for PacifiCorp at this time, as the disapproval action did not include a simultaneously finalized FIP. On January 30, 2025, the state of Wyoming submitted an "open letter" to the EPA stating its concerns about the agency's disapproval of the regional haze second planning period plan for the state. On January 31, 2025, the state also filed a petition for review in the Tenth Circuit. PacifiCorp filed a petition for reconsideration with the agency on January 30, 2025, and petition for review in the Tenth Circuit the next day. The EPA granted PacifiCorp's petition for reconsideration of EPA's disapproval action for Wyoming's Regional Haze state implementation plan submission for the second planning period April 30, 2025.

Colorado Regional Haze

Colorado Second Planning Period – Colorado's regional haze state implementation plan for the second planning period was adopted in phases in 2020 and 2021 by the Colorado Air Quality Control Commission. The state implementation plan 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 the EPA. On January 26, 2026, EPA finalized an action disapproving Colorado's Regional Haze state implementation plan for the second planning period. Specifically, EPA disapproved portions of Colorado's state

implementation plan submission pertaining to the cessation of coal handling at Hayden Units 1 and 2 and Craig Unit 2. Craig Unit 1 shut down by December 31, 2025, as required by Colorado's Regional Haze state implementation plan.

Mercury and Hazardous Air Pollutants

On April 25, 2024, the EPA finalized revisions to the National Emission Standards for Hazardous Air Pollutants for Coal- and Oil-Fired Electric Utility Steam Generating Units (EGUs), commonly referred to as the Mercury and Air Toxics Standards (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 existing lignite-fired units by 70 percent, sets a more stringent standard for emissions of filterable particulate matter (fPM) which serves as a surrogate for non-mercury hazardous air pollutant metals for existing coal-fired EGUs, and requires that continuous emissions monitoring be used to demonstrate compliance with the fPM standard. The EPA later proposed to repeal these amendments on June 17, 2025. The amendments that the EPA proposed to repeal include the revised fPM emission standard, the continuous emissions monitoring requirements; and the revised mercury emission standard for lignite-fired EGUs. The repeal of the 2024 Mercury and Air Toxics Standards (MATS) revisions was finalized as proposed on February 19, 2026. As a result, the applicable MATS requirements are those established in the original rule promulgated on February 16, 2012. All affected PacifiCorp units are in compliance with the current MATS requirements.

Coal Combustion Residuals

The EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule") in September 2020. A provision in Part A allows demonstrations to be submitted to the EPA allowing for operation of unlined Coal Combustion Residuals (CCR) ponds beyond the April 11, 2021, deadline for initiation of closure. PacifiCorp has submitted alternative closure demonstrations for the Naughton South Ash Pond and the Jim Bridger flue gas desulfurization (FGD) Pond 2. On October 12, 2023, Jim Bridger FGD Pond 2 ceased receiving waste, and the newly constructed FGD Pond 3 came into service. The EPA was notified on October 12, 2023, of PacifiCorp's withdrawal of its pending Part A alternative closure demonstration request. The Naughton South Ash Pond alternative closure demonstration remains under EPA review.

Separately, on August 10, 2017, the EPA issued proposed permitting guidance on how states' CCR permit programs should comply with the requirements of the final rule as authorized under the December 2016 Water Infrastructure Improvements for the Nation Act. To date, of the states in which PacifiCorp operates, only Wyoming has submitted an application to the EPA for approval of state permitting authority. Wyoming finalized its rule in late 2020 and received legislative approval in 2022. Wyoming submitted a primacy package to the EPA on February 6, 2023.

On May 8, 2024, the EPA finalized the legacy surface impoundment, which became effective on November 8, 2024. The rule encompasses legacy surface impoundments, which are inactive surface impoundments at inactive facilities; and CCR management units, which include CCR surface impoundments and landfills that closed prior to October 19, 2015, inactive CCR landfills, and other areas where CCR has been or is managed directly on the land. CCR management units include all units meeting that definition at active CCR facilities, as well as those at inactive

facilities with one or more legacy surface impoundment. EPA proposes to impose substantially the same regulatory obligations for both legacy surface impoundments and CCR management units as are applicable to currently regulated units, including groundwater monitoring and corrective action. All legacy surface impoundments and CCR management units would be required to initiate closure, including reclosure, within one year after the rule is finalized.

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

On August 5, 2024, Utah, Wyoming, and other Republican-led states filed a petition for review in the D.C. Circuit on the EPA's May 2024 legacy rule, arguing that the EPA acted arbitrarily and beyond its authority when enacting the new rule. On February 3, 2025, these same petitioners as well as power companies, utilities and trade groups filed their opening brief in a consolidated case contesting the rule in the D.C. Circuit.

On February 10, 2026, the EPA finalized an action to extend by three years, one compliance deadline applicable to certain CCR surface impoundments operating pursuant to the alternative closure requirements. Specifically, the EPA is proposing an extension of the deadline for owners and operators to complete closure of their unlined CCR surface impoundments larger than 40 acres from October 17, 2028, to October 17, 2031. Naughton's South Ash Pond is currently subject to the Part A requirements that would be impacted by this proposal if finalized as proposed.

On February 24, 2026, the EPA approved Wyoming's CCR permit program application. The approval allows Wyoming to operate a CCR program in lieu of the federal CCR permit program. Wyoming did not include several items in their application for program approval. For those items, which include requirements for vegetative cover for slope stability, suspension of groundwater monitoring, and groundwater protection standards for certain constituents, EPA will be the regulatory authority. The state of Utah adopted the federal final rule in September 2016, which required PacifiCorp to submit permit applications for two of its landfills by March 2017. Utah has signaled that they will similarly be submitting their program to the EPA for approval to obtain primacy over implementation of their CCR program.

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." In August 2014, EPA published a final rule, effective October 2014, under section 316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule establishes requirements that apply to existing power 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. The rule includes standards to address 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). 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. 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.

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 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. The 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, the 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 May 9, 2024, the EPA finalized the Supplemental ELG and Standards for the Steam Electric Generating Point Source Category (2024 ELG Rule), which includes a new subcategory for EGUs permanently ceasing coal combustion by 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. The rule also eliminates 2020 ELG Rule's less stringent BAT requirements for two subcategories: high-flow facilities and low-utilization electric generating units (LUEGUs), except to the extent they apply to one new permanent cessation of coal combustion subcategory. The rule maintains, however, the 2020 ELG Rule subcategory for EGUs permanently ceasing the combustion of coal by 2028 and oil-fired and small (50 megawatts (MW) or less) EGUs established in the 2015 rule. The rule finalizes additional reporting and recordkeeping requirements and zero-discharge limitations applicable after EGUs cease coal combustion, as well as procedural requirements for affected facilities to demonstrate permanent cessation of coal combustion or that permanent retirement will occur.

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. In October 2021, the Dave Johnston plant submitted a notice of planned participation in 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.

On December 31, 2025, the EPA finalized a rule to extend deadlines promulgated in the 2024 ELG Rule, update the 2024 ELG Rule's transfer provision to allow facilities to switch between compliance alternatives, and create authority for alternative applicability dates and paperwork submission dates, based on site-specific factors. PacifiCorp is evaluating compliance obligations in light of this final action.

State Policy Update

California

In 2002, California established a renewable portfolio standard (RPS) requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded several times since its inception. In September 2018, Governor Brown signed into law 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. The California Energy Commission, California Public Utilities Commission, and California Air Resources Board have not introduced rules on if and how electric utilities will demonstrate compliance with SB 100. 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 December 2022, Oregon Department of Environmental Quality (DEQ) 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 plug-in hybrid electric vehicles (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 medium- and heavy-duty vehicles (MHDV) 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. In 2025, the Oregon DEQ issued a delayed enforcement memo to the Advanced Clean Truck Rules.[3]

Washington

In December 2022, the Washington Department of Ecology adopted the Advanced Clean Cars II Rulemaking on Low and Zero Emission Vehicles which requires 100% of new LDVs be 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 MHDV 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

[3] See Oregon DEQ memorandum: https://www.oregon.gov/deq/aq/Documents/aqACTenfDiscDir.pdf

In 2025, Washington Department of Ecology issued updated guidance on the clean vehicles rules, pausing deficit generations at least through 2026.[4]

Utah

In March 2024, the Utah Legislature passed HB 191, Electrical Energy Amendments, which 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

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 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 pounds CO_2 per megawatt-hour, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. In September 2018, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 925 pounds CO_2 per megawatt-hour. The Washington Department of Commerce updated the standard in January 2025 and lowered the average estimated greenhouse gas emissions rate of combined-cycle natural gas power plants from 925 to 876 pounds per megawatt-hour.

Energy Gateway Transmission Program Planning

With the energization of Gateway South (Segment F) and Gateway West Segment D1 in 2024, there are three remaining segments in the Energy Gateway transmission project that have not yet been constructed. Figure 3.1 shows a high-level geography of the Energy Gateway transmission project.

Gateway West (Segment D3)
Under the National Environmental Policy Act (NEPA), the U.S. Bureau of Land Management (BLM) has completed the environmental impact statement (EIS) for the Gateway West project.

[4] See Washington Department of Ecology memorandum: https://apps.ecology.wa.gov/publications/documents/2514036.pdf

The BLM released its final EIS on April 26, 2013, followed by the record of decision (ROD) on November 14, 2013, providing a right-of-way grant for all of Segment D and for all but two segments of Segment E, followed with a record of decision on these two segments of the line on April 19, 2018. Gateway West (Segment D3) is the last part of segment D and is a single-circuit 500 kilovolt line running approximately 200 miles between the new Anticline substation and the Populus substation in southeast Idaho. The line is scheduled as in-service in 2035, at the earliest.

Gateway West (Segment E)

The Populus-to-Hemingway transmission project consists of two single-circuit 500 kilovolt lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho. The line is scheduled in service 2036 at the earliest.

Boardman to Hemingway

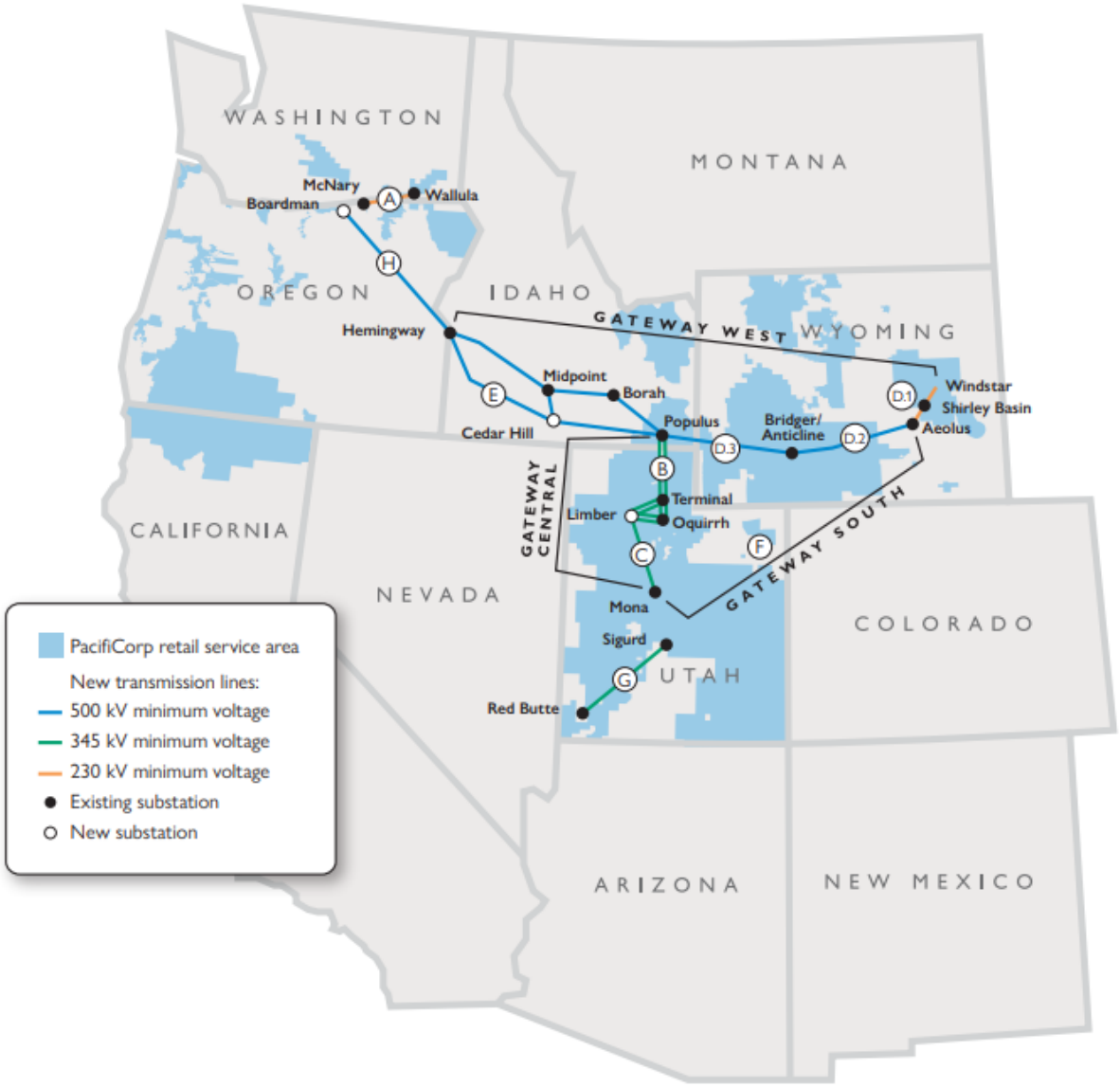
The Boardman to Hemingway project represents a significant improvement in the connection between PacifiCorp's east and west control areas. Idaho Power leads the permitting efforts on this project and PacifiCorp continues to support the permitting efforts under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement. The BLM's ROD was issued in November of 2017, followed by the U.S. Forest Service ROD issued on November 9, 2018. The Oregon Energy Facilities Siting Council's final order on the Site Certificate is currently under process. In January 2020, the three parties signatory to the permitting agreement entered a non-binding term sheet that addresses the terms required to move the project to the next step of construction. Construction is underway, with an expected in-service date of 12/31/2027.

Several years ago, PacifiCorp requested redirect rights from Bonneville Power Administration (BPA) to transfer energy from Longhorn to other points in PacifiCorp's service territory. PacifiCorp last received communication from BPA related to this request earlier this year, and the requests are still pending within BPA's transmission service request queue. As of this time, PacifiCorp is unsure as to when this study will be completed and whether or not the request will be granted in a timely manner.

In alignment with stakeholder feedback, PacifiCorp offers a "Boardman to Hemingway Redirects" sensitivity in Chapter 8, which assumes that BPA redirect rights are available as an option to serve load deeper in the west side of the system.[5,6,7]

[5] See Appendix G, stakeholder feedback form #2 (Sierra Club, et al.)
[6] See Appendix G, stakeholder feedback form #9 (Sierra Club, et al.)
[7] See Chapter 8 - Sensitivities

Figure 3.1 – Energy Gateway Map[a]



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

Regional Markets

Increased renewable generation has contributed to the need for balancing demand and supply across a broader and more diverse market. For sub-hourly balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the EIM. The EIM became operational November 1, 2014, and currently has 22 utilities participating with Black Hills and PowerWatch (formerly Berkshire Hathaway Energy Montana) planning to enter in 2026.[8] The multi-service area footprint brings greater resource and geographical diversity allowing for

[8] https://www.westerneim.com/Pages/About/default.aspx

increased reliability and cost savings in balancing generation with demand using fifteen-minute interchange scheduling and five-minute dispatch. The CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. The CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. In December 2022, PacifiCorp announced its plan to join the CAISO's Extended Day-Ahead Market which is an extension of the EIM with planning practices that are done in the day-ahead timeframe. PacifiCorp and CAISO are preparing for parallel operations, where EDAM-related functionality will be tested but not operationally or financially binding, leading up to a scheduled go-live date in May 2026. Similarly, Portland General Electric is scheduled to go-live in October 2026.

Since the Western Resource Adequacy Program (WRAP) was announced in 2021, PacifiCorp participated in design and implementation of the program.[9] WRAP includes a forward showing (FS) planning program and an operational program to help participants that are experiencing extreme events meet customer demand. WRAP does not replace or supplant the resource planning processes used by states or provinces or the regulatory requirements of the Federal Energy Regulatory Commission, North America Electric Reliability Corporation or Western Electricity Coordinating Council. The program is designed to be supplemental and complementary to those processes and requirements.

The 2025 IRP contemplated PacifiCorp's binding participation in WRAP starting in 2028; however, PacifiCorp provided a two-year notice that it was exiting WRAP on October 30, 2025, ahead of the start of binding compliance in November 2027.[10] Given its exit from WRAP, PacifiCorp can continue making use of a broader range of market products than are allowed for WRAP compliance. PacifiCorp is continuing to evaluate ways to manage resource supply risk through participation in regional resource adequacy programs.

[9] https://www.westernpowerpool.org/

[10] PacifiCorp's WRAP Withdrawal Letter. October 30, 2025. Available at: https://www.westernpowerpool.org/private-media/documents/WRAP_Withdrawal_Letter_-_Oct_30_2025.pdf

CHAPTER 4 – LOAD AND RESOURCE BALANCE

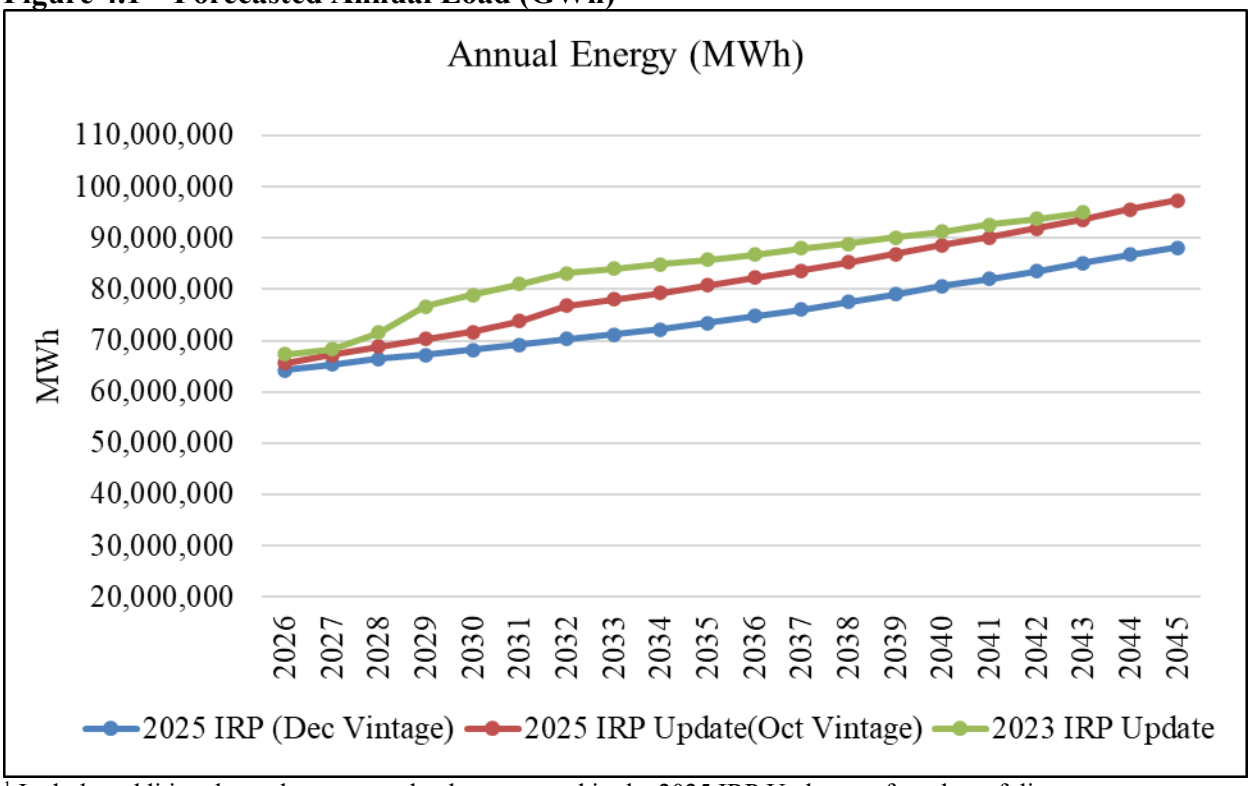
Introduction

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

System Coincident Peak Load Forecast

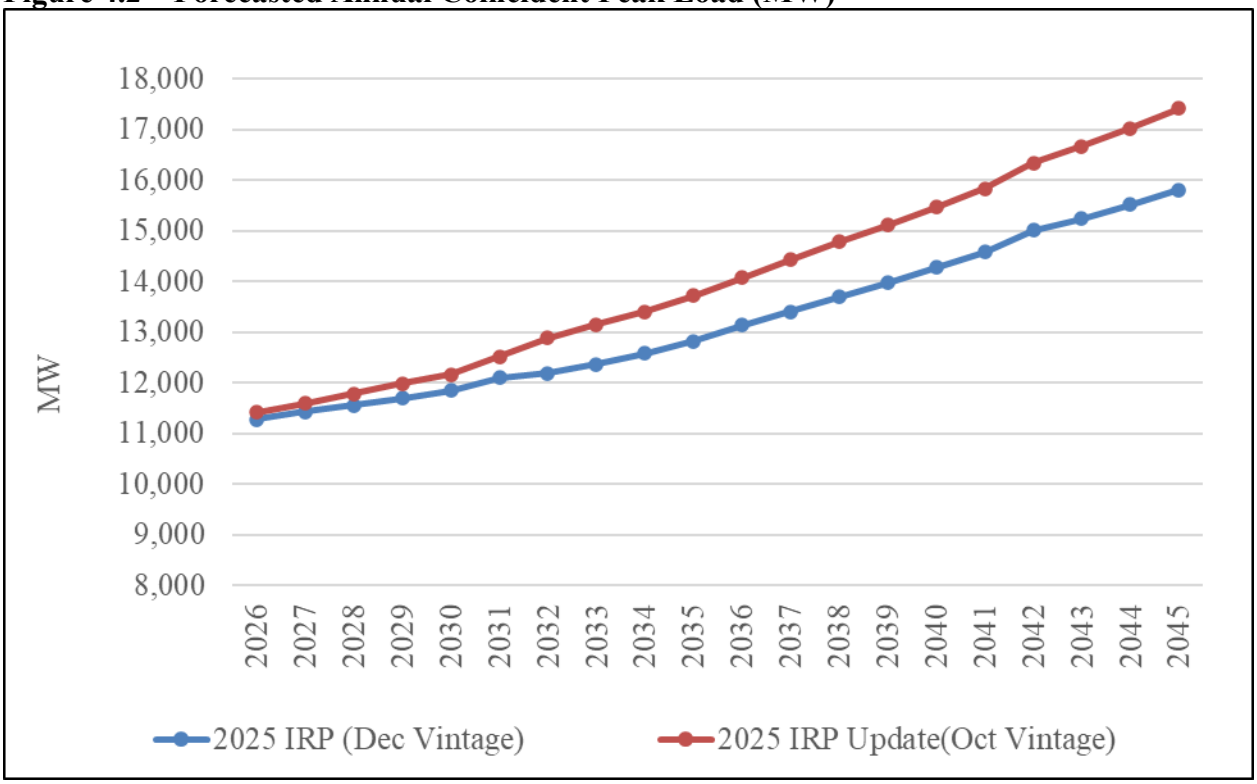
The 2025 Integrated Resource Plan (IRP) Update relies on PacifiCorp's October 2025 load forecast. Figure 4.1 compares PacifiCorp's most recent load forecast to the forecast used for the 2025 IRP and the 2023 IRP Update. Figure 4.2 compares PacifiCorp's most recent coincident system peak load forecast to the forecast used for the 2025 IRP. Considering that PacifiCorp analyzes incremental energy efficiency and direct-load control programs as demand-side resource options in its IRP, both figures exclude incremental energy efficiency savings and direct-load control capacity included in the updated resource portfolio.

Figure 4.1 – Forecasted Annual Load (GWh)[1]



[1] Includes additional new large-meter load represented in the 2025 IRP Update preferred portfolio.

Figure 4.2 – Forecasted Annual Coincident Peak Load (MW)[1]



[1] Includes additional new large-metered load represented in the 2025 IRP Update preferred portfolio.

Resource Updates

Table 4.1 summarizes recent long-term contracts that have been executed and modeled in PLEXOS since the 2025 IRP was prepared.

Table 4.1 – New Power Purchase Agreements

Power Purchase Agreements	Resource Type	Capacity (MW)	State	COD Year
Oregon Community Solar				
Goodling Community Solar	Solar	1.0	Oregon	2025
Chapman Creek Solar	Solar	3.0	Oregon	2025
Marble Solar	Solar	2.9	Oregon	2025
Perrydale Solar	Solar	1.0	Oregon	2025
Burlingame Solar	Solar	2.1	Oregon	2025
Kelly Creek Solar	Solar	2.3	Oregon	2026
	Sub-total	***12.2***		
Other Qualifying Facilities				
Kettle Butte Digester	Biogas	1.7	Idaho	2025
Eagle Point Irrigation District	Hydro	0.9	Oregon	2025
Dee Bridge Hydro	Hydro	0.1	Oregon	2026
	Sub-total	***2.8***		
	Total	***15.0***		

Updated Capacity Load-and-Resource Balance

Load-and-Resource Balance Components

The capacity balance compares generating capability to load obligations across both summer and winter. For the 2025 IRP Update, the load and resource balance uses 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 Update. 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. The load and resource balances for capacity presented 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. The capacity balance makes use of the following main components: resources, obligation, reserves, system 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.

Existing Resources

Capacity contribution is a measure of the ability for a resource to reliably meet demand.

Coal and Gas resources
These categories include all thermal plants. This includes the existing fleet of coal-fueled units, coal-fueled units that have converted to natural gas-fueled, and natural gas combustion turbines and combined cycle combustion turbines. Presently, these thermal resources account for well over half of the firm capacity available in the PacifiCorp system.

Energy Storage
Energy storage resources can be called upon as needed, but only for a limited duration before they must be recharged. For the purpose of the load and resource balance in the 2025 IRP Update, the capacity contribution is also based on the updated WRAP qualifying capacity contribution values. The WRAP capacity contributions decrease over time starting out at just under 80% in 2027 and tapering down to an average of 59% by 2045.

Variable Energy Resources: Wind and Solar
The availability of wind and solar resources is dependent on weather conditions. With access to wind and solar technologies and a broad geographic area, PacifiCorp's system is better suited to utilizing the capacity provided by wind and solar than most other utilities. However, many periods still exist in which both wind and solar output is at low levels, both in individual hours, and over an extended length of time. While short-duration energy storage can help to address a few hours of shortfalls, weather events which result in low variable energy resource output over multiple days limit the capacity contribution of these resources, as well as the contribution of short-duration energy storage. Similar to energy storage, the wind and solar WRAP capacity contributions decrease over time starting out at and average of 23% in 2027 and tapering down to an average of 19.5% by 2045.

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

Obligation

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

Load and Distributed Generation
The largest component of the obligation is retail load. In the 2025 IRP Update, 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 Balancing Authority Areas thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks. The energy balance counts the average load on a monthly basis. For simplicity, load net of distributed generation is referred to as load in the following sections.

Energy Efficiency
An adjustment is made to load to remove the projected embedded energy efficiency as a reduction to load. Due to timing issues with the vintage of the load forecast, there was a level of 2024 energy efficiency that was not incorporated in the forecast for the 2025 IRP. The 2024 energy efficiency

forecast of 158 megawatts was accounted for by adding an existing energy efficiency resource in the load-and-resource balance; this adjustment was not required for the 2025 IRP Update because the 2024 projected embedded energy efficiency is included in the load forecast. The energy efficiency line includes the selected energy efficiency from the 2025 IRP Update 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 Update, demand response is used for operating reserves and dispatched within the PLEXOS model based on economic 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 currently. 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.

Planning Reserve Margin

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

System Position

The system position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources. This view of system need does not consider jurisdictions, but rather is a traditional view based on which balancing authority contains the surplus or deficit. For this reason, the traditional "system" view might now be better characterized as a "total" view. This is because in modern parlance, "system" increasingly refers to a shared obligation or need, and not the total obligation or need.

Capacity Balance Determination and Results

Methodology

The capacity balance is developed by first determining the system coincident peak load for each of the 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 **-** Sales

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

Obligation = Load – Distributed generation – Energy Efficiency

The volume of reserves to be added to the obligation is then calculated. This is accomplished by the net system obligation calculated above multiplied by the 12.3 percent PRM for July and 12.7 percent PRM for December adopted from WRAP for the 2025 IRP Update. The formula for this calculation is:

Planning Reserves = Obligation x PRM

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

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

Capacity Balance Results

Table 4.2 and Table 4.3 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using the target PRM mentioned previously to calculate the planning reserve amount. Balances for PacifiCorp's system and the east and west control areas are shown. While east and west control area balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis.

Table 4.2 – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2025 IRP Update (2027-2036) (Megawatts)[1]

East	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Coal	3,592	3,407	3,133	3,133	2,866	2,866	2,866	2,866	2,866	2,866
Gas	3,360	3,360	3,534	3,535	3,535	3,535	3,535	3,535	3,535	3,535
Hydroelectric	75	75	75	75	75	75	75	75	75	75
Wind	545	545	544	535	521	521	521	520	520	520
Solar	602	596	590	584	577	571	565	559	552	546
Other Renewable	48	48	47	47	46	46	45	45	44	44
Storage	844	834	824	815	806	796	787	777	767	758
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	400	391	382	373	364	353	340	328	318	295
Demand Response	413	410	407	403	400	397	393	390	387	383
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,435)	(1,163)	(997)	(927)	(554)	(542)	(384)	(266)	(114)	0
East Existing Resources	**8,444**	**8,503**	**8,540**	**8,572**	**8,635**	**8,616**	**8,742**	**8,828**	**8,950**	**9,021**
Load	7,825	7,999	8,161	8,329	8,542	8,562	8,764	8,987	9,242	9,549
Distributed Generation	(143)	(191)	(242)	(297)	(356)	(261)	(297)	(330)	(361)	(392)
Energy Efficiency	(163)	(237)	(314)	(399)	(496)	(629)	(682)	(796)	(911)	(979)
East Total obligation	**7,519**	**7,571**	**7,604**	**7,633**	**7,690**	**7,672**	**7,784**	**7,861**	**7,970**	**8,178**
Planning Reserve Margin (12.3%)	925	931	935	939	946	944	957	967	980	1,006
East Obligation + Reserves	8,444	8,503	8,540	8,572	8,635	8,616	8,742	8,828	8,950	9,184
East Position	0	0	0	0	0	0	0	0	0	(163)
West										
Coal	97	97	97	0	0	0	0	0	0	0
Gas	681	681	681	681	681	681	681	681	681	681
Hydroelectric	710	710	710	710	710	710	710	710	710	710
Wind	39	39	39	39	39	39	39	39	39	39
Solar	71	70	69	69	65	65	65	65	65	65
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	1	1	1	1	1	1	1	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	230	226	219	215	209	200	196	193	189	184
Demand Response	16	16	16	16	15	15	15	15	15	14
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	1,435	1,163	997	927	554	542	384	266	114	0
West Existing Resources	**3,280**	**3,002**	**2,828**	**2,657**	**2,274**	**2,253**	**2,090**	**1,968**	**1,812**	**1,693**
Load	3,972	4,050	4,171	4,267	4,502	4,693	4,807	4,890	4,987	5,090
Distributed Generation	(59)	(82)	(108)	(136)	(166)	(107)	(123)	(139)	(154)	(168)
Energy Efficiency	(110)	(151)	(192)	(235)	(289)	(330)	(361)	(403)	(443)	(486)
West Total obligation	**3,804**	**3,816**	**3,871**	**3,896**	**4,047**	**4,256**	**4,323**	**4,348**	**4,391**	**4,436**
Planning Reserve Margin (12.3%)	468	469	476	479	498	524	532	535	540	546
West Obligation + Reserves	4,272	4,285	4,347	4,375	4,545	4,780	4,854	4,883	4,931	4,982
West Position	(992)	(1,284)	(1,519)	(1,718)	(2,271)	(2,527)	(2,764)	(2,915)	(3,119)	(3,289)
System										
Total Resources	11,724	11,505	11,368	11,228	10,909	10,869	10,832	10,795	10,762	10,714
Obligation	11,323	11,387	11,475	11,529	11,737	11,928	12,107	12,209	12,360	12,615
Planning Reserves (12.3%)	1,393	1,401	1,411	1,418	1,444	1,467	1,489	1,502	1,520	1,552
Obligation + Reserves	12,716	12,788	12,887	12,947	13,181	13,396	13,596	13,710	13,881	14,166
System Position	(992)	(1,284)	(1,519)	(1,718)	(2,271)	(2,527)	(2,764)	(2,915)	(3,119)	(3,452)
Uncommitted FOTs to meet remaining Need	992	1,284	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	0	0	(1,519)	(1,718)	(2,271)	(2,527)	(2,764)	(2,915)	(3,119)	(3,452)

[1] The Energy Efficiency line includes selected Energy Efficiency from the 2025 IRP Update resource portfolio.

Table 4.2 (cont.) – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2025 IRP Update (2037-2045) (Megawatts)[2]

East	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,866	2,866	2,866	2,866	2,866	2,866	2,866	2,866	2,866
Gas	3,535	3,535	3,535	3,322	3,322	3,322	3,322	3,234	3,234
Hydroelectric	75	75	75	75	75	75	75	75	75
Wind	520	520	519	519	463	462	462	462	462
Solar	509	503	498	492	487	481	476	451	446
Other Renewable	43	11	11	10	9	9	8	8	0
Storage	748	739	730	720	711	702	692	683	674
Purchase	0	0	0	0	0	0	0	0	0
Qualifying Facilities	243	234	226	214	207	199	192	185	178
Demand Response	380	377	373	370	367	363	360	357	353
Sale	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0
East Existing Resources	**8,918**	**8,860**	**8,832**	**8,589**	**8,506**	**8,480**	**8,454**	**8,319**	**8,287**
Load	9,813	10,102	10,370	10,649	10,943	11,252	11,556	11,837	12,133
Distributed Generation	(421)	(450)	(478)	(505)	(533)	(559)	(585)	(610)	(636)
Energy Efficiency	(1,072)	(1,186)	(1,284)	(1,365)	(1,457)	(1,436)	(1,526)	(1,546)	(1,574)
East Total obligation	**8,319**	**8,466**	**8,608**	**8,778**	**8,953**	**9,257**	**9,444**	**9,681**	**9,924**
Planning Reserve Margin (12.3%)	1,023	1,041	1,059	1,080	1,101	1,139	1,162	1,191	1,221
East Obligation + Reserves	9,343	9,507	9,666	9,858	10,054	10,395	10,606	10,872	11,145
East Position	(425)	(647)	(834)	(1,269)	(1,548)	(1,915)	(2,153)	(2,553)	(2,857)
West									
Coal	0	0	0	0	0	0	0	0	0
Gas	681	681	681	681	681	681	681	681	681
Hydroelectric	710	710	710	710	710	710	710	710	710
Wind	39	39	39	39	39	39	39	39	39
Solar	65	65	65	65	25	25	25	25	25
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0
Qualifying Facilities	168	164	159	156	152	149	136	132	128
Demand Response	14	14	14	14	13	13	13	13	12
Sale	0	0	0	0	0	0	0	0	0
Transfers	0	0	0	0	0	0	0	0	0
West Existing Resources	**1,676**	**1,672**	**1,667**	**1,664**	**1,621**	**1,617**	**1,604**	**1,600**	**1,595**
Load	5,224	5,328	5,437	5,544	5,667	5,905	5,972	6,083	6,214
Distributed Generation	(183)	(197)	(211)	(225)	(240)	(254)	(267)	(281)	(295)
New Energy Efficiency	(541)	(573)	(605)	(631)	(665)	(747)	(561)	(568)	(576)
West Total obligation	**4,500**	**4,558**	**4,621**	**4,688**	**4,762**	**4,904**	**5,144**	**5,234**	**5,343**
Planning Reserve Margin (12.3%)	553	561	568	577	586	603	633	644	657
West Obligation + Reserves	5,053	5,118	5,189	5,264	5,348	5,508	5,776	5,878	6,001
West Position	(3,377)	(3,447)	(3,522)	(3,600)	(3,727)	(3,890)	(4,173)	(4,278)	(4,405)
System									
Total Resources	10,595	10,531	10,499	10,253	10,127	10,097	10,057	9,919	9,883
Obligation	12,819	13,023	13,228	13,466	13,715	14,161	14,588	14,915	15,267
Planning Reserves (12.3%)	1,577	1,602	1,627	1,656	1,687	1,742	1,794	1,835	1,878
Obligation + Reserves	14,396	14,625	14,855	15,122	15,402	15,903	16,382	16,750	17,145
System Position	(3,801)	(4,094)	(4,357)	(4,869)	(5,275)	(5,806)	(6,325)	(6,831)	(7,262)
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	(3,801)	(4,094)	(4,357)	(4,869)	(5,275)	(5,806)	(6,325)	(6,831)	(7,262)

[2] The Energy Efficiency line includes selected Energy Efficiency from the 2025 IRP Update resource portfolio.

Table 4.3 – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2025 IRP Update (2027-2036) (Megawatts)

East	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Coal	3,705	3,481	3,184	3,183	2,906	2,906	2,906	2,906	2,906	2,906
Gas	3,405	3,405	3,596	3,597	3,597	3,597	3,597	3,597	3,597	3,597
Hydroelectric	32	32	32	32	32	32	32	32	32	32
Wind	1,081	1,081	1,081	1,058	1,018	1,018	1,018	1,018	1,018	1,018
Solar	156	154	153	151	149	147	146	144	142	141
Other Renewable	44	44	43	43	42	42	41	41	40	40
Storage	577	567	558	549	539	529	520	510	501	492
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	178	173	168	163	158	151	142	126	122	114
Demand Response	139	139	139	139	139	139	139	139	139	139
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,600)	(1,600)	(1,562)	(1,428)	(1,203)	(1,005)	(802)	(602)
East Existing Resources	**7,716**	**7,477**	**7,353**	**7,314**	**7,019**	**7,134**	**7,339**	**7,509**	**7,696**	**7,877**
Load	5,984	6,104	6,245	6,350	6,536	6,705	6,946	7,166	7,399	7,605
Distributed Generation	(2)	(3)	(4)	(5)	(6)	(8)	(9)	(9)	(10)	(11)
Energy Efficiency	(119)	(162)	(205)	(251)	(302)	(367)	(426)	(494)	(560)	(605)
East Total obligation	**5,862**	**5,938**	**6,036**	**6,094**	**6,228**	**6,330**	**6,512**	**6,662**	**6,828**	**6,989**
Planning Reserve Margin (12.7%)	744	754	767	774	791	804	827	846	867	888
East Obligation + Reserves	6,606	6,692	6,803	6,868	7,019	7,134	7,339	7,509	7,696	7,877
East Position	1,110	785	551	446	0	0	0	0	0	0
West										
Coal	132	132	132	0	0	0	0	0	0	0
Gas	719	719	719	719	719	719	719	719	719	719
Hydroelectric	728	728	728	728	728	728	728	728	728	728
Wind	41	41	41	41	41	41	41	41	41	41
Solar	6	6	6	5	4	4	4	4	4	4
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	1	1	1	1	1	1	1	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	64	63	61	61	60	59	59	58	58	56
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	1,562	1,428	1,203	1,005	802	602
West Existing Resources	**3,291**	**3,290**	**3,288**	**3,156**	**3,116**	**2,982**	**2,755**	**2,557**	**2,353**	**2,151**
Load	3,671	3,743	3,865	3,943	4,135	4,342	4,442	4,515	4,603	4,735
Distributed Generation	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)
Energy Efficiency	(98)	(152)	(208)	(266)	(325)	(384)	(440)	(495)	(553)	(610)
West Total obligation	**3,572**	**3,590**	**3,656**	**3,676**	**3,809**	**3,957**	**4,000**	**4,017**	**4,048**	**4,123**
Planning Reserve Margin (12.7%)	454	456	464	467	484	503	508	510	514	524
West Obligation + Reserves	4,026	4,046	4,120	4,142	4,292	4,459	4,508	4,527	4,562	4,647
West Position	(735)	(756)	(831)	(987)	(1,176)	(1,478)	(1,753)	(1,971)	(2,209)	(2,495)
System										
Total Resources	11,007	10,767	10,642	10,470	10,135	10,116	10,095	10,065	10,049	10,028
Obligation	9,434	9,528	9,692	9,769	10,037	10,287	10,512	10,680	10,876	11,112
Planning Reserves (12.7%)	1,160	1,172	1,192	1,202	1,234	1,265	1,293	1,314	1,338	1,367
Obligation + Reserves	10,594	10,700	10,884	10,971	11,271	11,552	11,805	11,993	12,214	12,479
System Position	413	67	(242)	(501)	(1,136)	(1,437)	(1,711)	(1,928)	(2,165)	(2,451)
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	413	67	(242)	(501)	(1,136)	(1,437)	(1,711)	(1,928)	(2,165)	(2,451)

Table 4.3 (cont.) – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2025 IRP Update (2037-2045) (Megawatts)[3]

East	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,906	2,906	2,906	2,906	2,906	2,906	2,906	2,906	2,906
Gas	3,597	3,597	3,597	3,381	3,381	3,381	3,381	3,278	3,278
Hydroelectric	32	32	32	32	32	32	32	32	32
Wind	1,018	1,018	1,018	1,018	924	924	924	924	924
Solar	137	136	134	132	131	129	127	118	117
Other Renewable	39	8	8	8	7	6	6	5	0
Storage	482	472	463	454	444	435	425	416	406
Purchase	0	0	0	0	0	0	0	0	0
Qualifying Facilities	100	95	92	88	84	80	76	73	69
Demand Response	139	139	139	139	139	139	139	139	139
Sale	0	0	0	0	0	0	0	0	0
Transfers	(313)	(54)	0	0	0	0	0	0	0
East Existing Resources	**8,139**	**8,350**	**8,389**	**8,158**	**8,048**	**8,032**	**8,017**	**7,892**	**7,872**
Load	7,902	8,151	8,440	8,687	8,941	9,263	9,560	9,853	10,155
Distributed Generation	(11)	(12)	(13)	(13)	(13)	(14)	(14)	(15)	(15)
Energy Efficiency	(669)	(730)	(785)	(836)	(895)	(903)	(965)	(997)	(1,044)
East Total obligation	**7,221**	**7,409**	**7,643**	**7,838**	**8,033**	**8,346**	**8,581**	**8,841**	**9,096**
Planning Reserve Margin (12.7%)	888	911	940	964	988	1,027	1,055	1,087	1,119
East Obligation + Reserves	8,110	8,321	8,583	8,802	9,022	9,373	9,636	9,928	10,215
East Position	29	30	(193)	(644)	(974)	(1,341)	(1,619)	(2,036)	(2,343)
West									
Coal	0	0	0	0	0	0	0	0	0
Gas	719	719	719	720	720	720	720	720	720
Hydroelectric	728	728	728	728	728	728	728	728	728
Wind	41	41	41	41	41	41	41	41	41
Solar	4	4	4	4	2	2	2	2	2
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	55	54	53	52	52	51	50	50
Demand Response	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0
Transfers	313	54	0	0	0	0	0	0	0
West Existing Resources	**1,862**	**1,602**	**1,547**	**1,547**	**1,543**	**1,543**	**1,542**	**1,541**	**1,541**
Load	4,824	4,900	5,009	5,124	5,235	5,389	5,509	5,608	5,738
Distributed Generation	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)
Energy Efficiency	(653)	(700)	(746)	(802)	(843)	(884)	(767)	(784)	(801)
West Total obligation	**4,168**	**4,197**	**4,261**	**4,319**	**4,389**	**4,501**	**4,739**	**4,820**	**4,933**
Planning Reserve Margin (12.7%)	529	533	541	548	557	572	602	612	627
West Obligation + Reserves	4,698	4,730	4,802	4,867	4,946	5,072	5,341	5,432	5,560
West Position	(2,836)	(3,127)	(3,255)	(3,320)	(3,403)	(3,529)	(3,799)	(3,891)	(4,019)
System									
Total Resources	10,000	9,953	9,936	9,705	9,591	9,575	9,559	9,433	9,413
Obligation	11,390	11,606	11,904	12,157	12,422	12,847	13,320	13,661	14,029
Planning Reserves (12.7%)	1,401	1,428	1,464	1,495	1,528	1,580	1,638	1,680	1,726
Obligation + Reserves	12,791	13,034	13,368	13,652	13,950	14,427	14,958	15,341	15,755
System Position	(2,790)	(3,081)	(3,432)	(3,947)	(4,359)	(4,852)	(5,399)	(5,908)	(6,342)
Uncommitted FOTs to meet remaining Need	0	0	0	0	0	0	0	0	0
Net Surplus/(Deficit)	(2,790)	(3,081)	(3,432)	(3,947)	(4,359)	(4,852)	(5,399)	(5,908)	(6,342)

[3] The Energy Efficiency line includes selected Energy Efficiency from the 2025 IRP Update resource portfolio.

Figure 4.3 and Figure 4.4 are graphic representations of the above tables for the 2025 IRP Update annual capacity position for the summer system, and winter system respectively. Also shown in the summer system capacity position graph are the jurisdictional reliability need.

Figure 4.3 – Summer System Capacity Position Trend

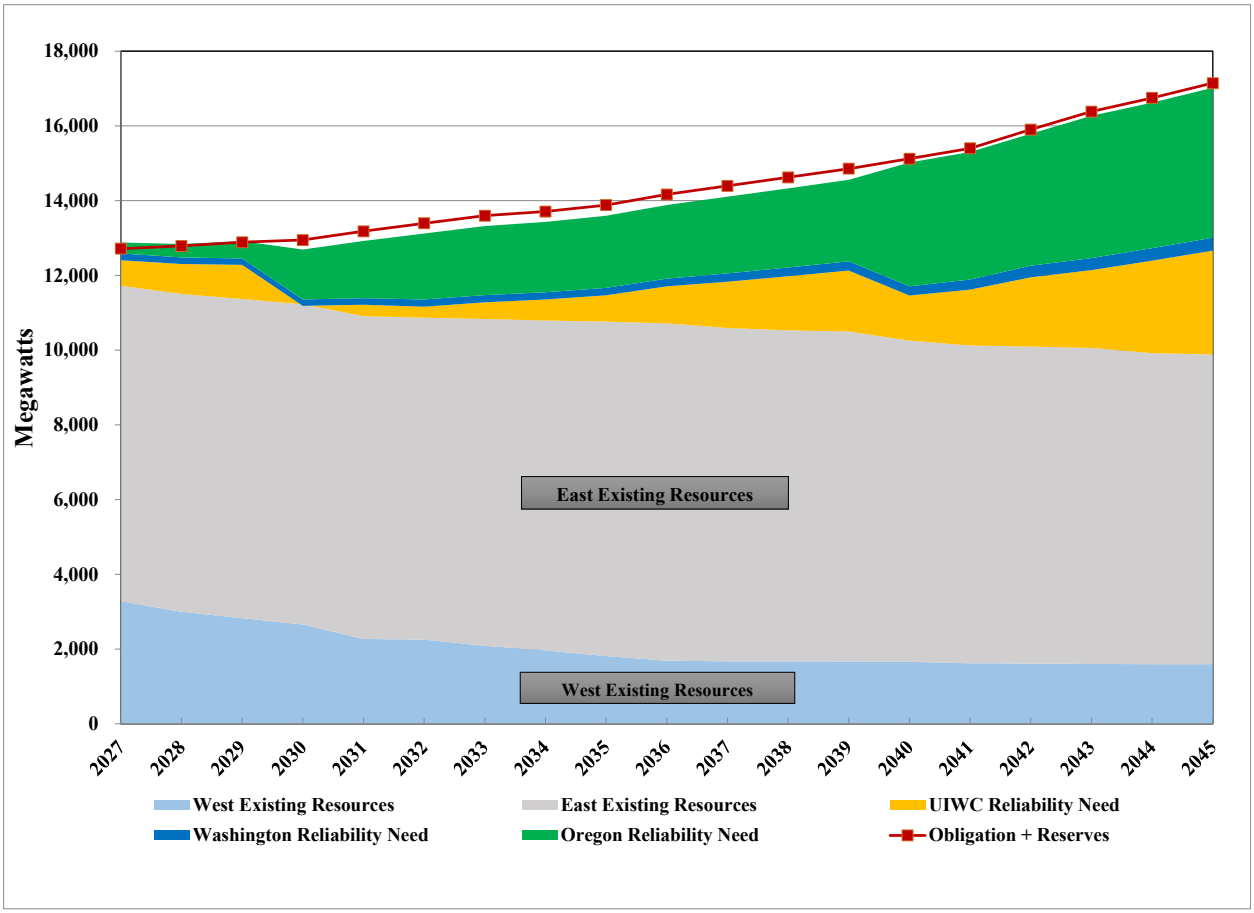
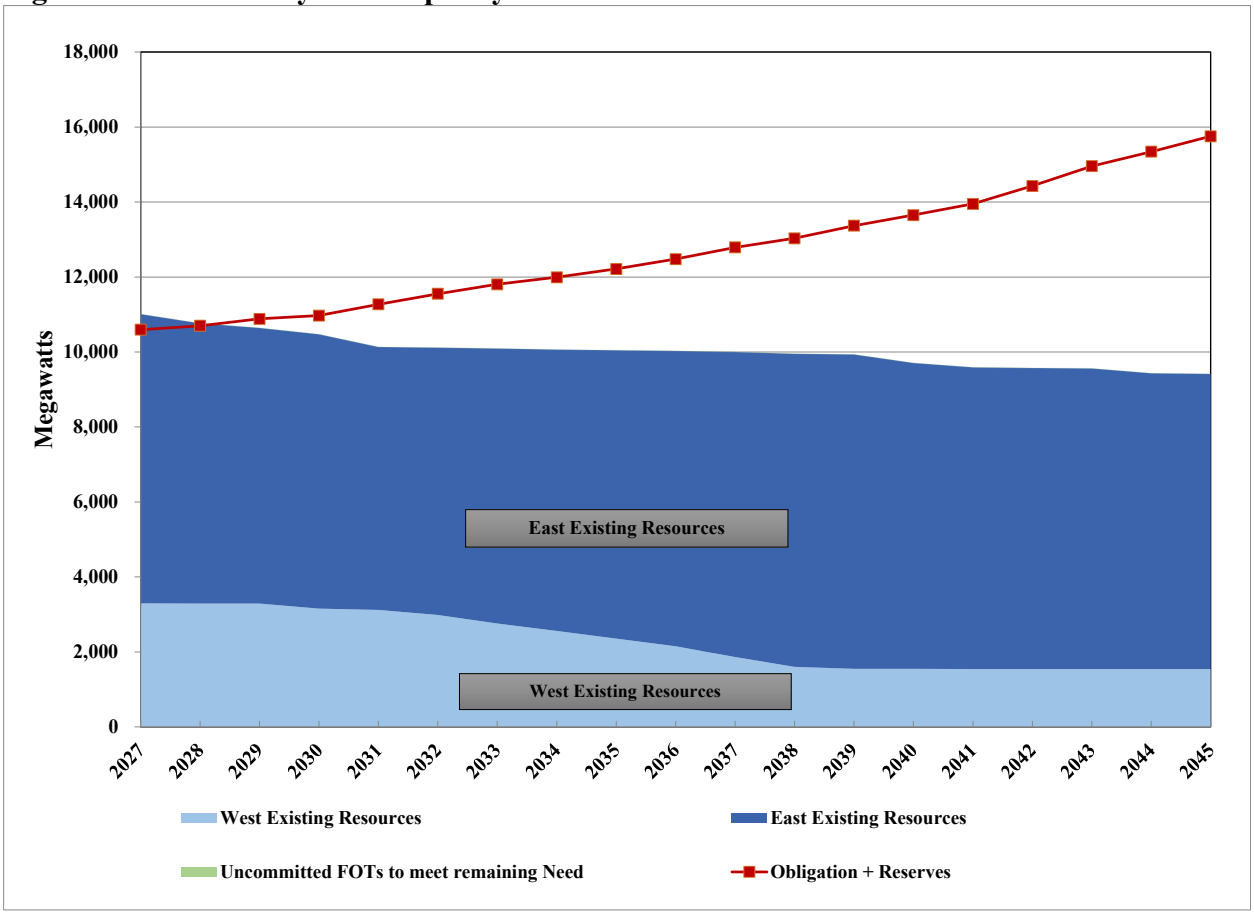


Figure 4.4 – Winter System Capacity Position Trend



CHAPTER 5 – RESOURCE OPTIONS

General Assumptions

The study period for the 2025 IRP Update is 2027-2045, with a focus on the 2027-2029 planning horizon.[1] While many assumptions are unchanged from the 2025 IRP, PacifiCorp has materially updated certain assumptions in the 2025 IRP Update as discussed below.

Inflation Rates

The 2025 IRP Update model simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.22% is assumed. The annual escalation rate reflects the average of annual inflation rate projections for the 20-year study period, using PacifiCorp's September 2025 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for Gross Domestic Product inflator and Consumer Price Index.

Discount Factor

The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2025 IRP Update is 6.33%. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[2] Present-value revenue requirement values reported in the 2025 IRP Update are reported in 2025 dollars.

Front Office Transactions

PacifiCorp develops its front office transaction (FOT) planning limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and depth, and consideration of regional resource supply.

New to the 2025 IRP Update, PacifiCorp modeled block market purchases as a selectable resource option. Block purchases were available for the model to select in 25 MW increments or "blocks" up to 500 MW per year in Mid-C and Wyoming East from 2030 onward, priced at Mid-C and Palo Verde heavy-load hour (HLH) and light-load hour (LLH) forward prices. While the model could select any amount up to 500 MW in 25 MW increments in both regions, the purchase was only available for the months of July and December where, if selected, the model was required to pay for the block purchase in all hours in those months in a given year. Unlike typical long-term resources, which generally have an economic that extends beyond the end of the IRP model horizon, block market purchases represent a commitment for a single year, and the selected quantity can be adjusted up or down in each successive year.

The block purchase contributed to both UIWC energy needs and system WRAP requirements, selectable only in the system model run. This block treatment provides substantially more certainty

[1] As year 2025 has passed into history and 2026 is underway, they are not generally reported in this 2025 IRP Update; however, some workpapers will still contain 2025-26 information as an artifact of developing data for the remainder of the 20-year modeling horizon.
[2] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

that the assumed purchase would be available because it is contracted significantly in advance of any triggering event, and also more accurately reflects actual front office activity.

Block products are not eligible to be selected in the Oregon and Washington jurisdictional runs in the IRP Update. Block products are not eligible to serve Oregon and Washington per the current assumption that these are unspecified, non-REC generating purchases. As such, an unspecified purchase would contribute to Oregon emissions and harm compliance and also would not contribute RECs to Washington's CETA position. PacifiCorp is open to revising this assumption for the 2027 IRP.[3]

In the 2025 IRP, no market purchases provided firm capacity to meet WRAP requirements; market purchases in the 2025 IRP were all hourly economic purchases to fill energy needs, limited only by transmission limits and during key hours on the top five loads days in each month. PacifiCorp modeled market purchases in this manner in the 2025 IRP in light of Western Resource Adequacy Program (WRAP) rules which did not count standard heavy-load-hour (HLH) market products toward resource adequacy requirements because those standard transactions do not have a specified source. Given that PacifiCorp has provided notice that the Company will be exiting WRAP ahead of binding operations, this restriction on market products is no longer necessary. Additionally, stakeholders have requested that the IRP compare the economics of resource procurement and additional firm market purchases. The goal in modeling a selectable quantity of firm market purchases in each year from 2030 onward in the 2025 IRP Update is to compare the economics of firm market purchases which have unique characteristics compared to hourly economic purchases and additional long-term resource procurement.

Stakeholders have expressed concern that the near-term years of the IRP continue to allow liberal market purchases.[4] Because of the time required to procure and bring online long-term resources, short-term resources are always necessary to meet requirements in the first few years of an IRP, regardless of quantity. While upper limit values for short-term purchases have been listed in the early years of the load and resource balance, short-term resource procurement in that time frame will always be "as necessary" to meet requirements. Over the longer term, both long-term and short-term resources are viable alternatives and their relative costs and risks can be evaluated in the IRP. A reduction in market reliance only occurs with successful procurement of long-term resources, which is more complex than IRP modeling, requiring both a viable, shovel-ready project and two counterparties that are willing and able to make a long-term commitment. For instance, while PacifiCorp's battery storage procurement in its 2020 and 2022 all-source request for proposals was limited, PacifiCorp pursued additional battery storage outside of those processes and has approximately 1,000 MW of battery storage scheduled to come online in 2026, reducing reliance on short-term purchases this year.

Federal Tax Credits

The 2025 IRP reflected Inflation Reduction Act ("IRA") tax credit eligibility. While the IRA has not been fully repealed, on July 4, 2025, H.R.1 – the One Big Beautiful Bill Act (OBBBA) - became law and materially impacts the costs and benefits of certain renewable and storage resources. H.R.1 phases out and repeals certain IRA tax credits, resulting in a narrow window of

[3] See Appendix G, stakeholder feedback form #20 (Public Utility Commission of Oregon)
[4] See Appendix G, stakeholder feedback form #2 (Sierra Club, et al.)

time in which new projects may qualify for federal tax credits. New Foreign Entity of Concern (FEOC) restrictions could also potentially further limit the ability for projects to qualify. In accordance with H.R.1 and the assumed online date for certain new proxy resources, in the 2025 IRP Update, new wind and solar resources will not be eligible for federal tax credits while proxy geothermal, pumped hydro[5] storage and nuclear will be eligible for tax credits if built no later than 1/1/2037. Additionally, proxy battery storage resources will be eligible for investment tax credits if built no later than 1/1/2037.

Stochastic Parameters

Stochastic parameters assumed in the 2025 IRP Update are consistent with those applied in the 2025 IRP. PacifiCorp provided a detailed description of its stochastic parameters and their development in Volume II, Appendix H of the 2025 IRP, filed March 31, 2025.

Flexible Reserve Study

PacifiCorp applied its Flexible Reserve Study methodology from the 2025 IRP in its 2025 IRP Update. PacifiCorp provided a detailed description of its Flexible Reserve Study in Volume II, Appendix F of the 2025 IRP.

Natural Gas and Power Market Price Updates

Portfolio modeling for the 2025 IRP Update was prepared using four market price forecasts. This includes the official forward price curve (OFPC) and three scenarios.

Wholesale Electricity and Natural Gas Forward Prices

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 Update modeling inputs were prepared, the September 2025 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.[6] As such, these 36 months are market forwards as of September 2025. 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[7] (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

[5] While the Update does not review each resource type, specific stakeholder interest is noted in pumped hydro. See Appendix G, stakeholder feedback form #11 (rPlus Energies, LLC)
[6] The September 2025 OFPC prompt month is November 2025; October 2025 would be traded as "balance of month" when the OFPC is released.
[7] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

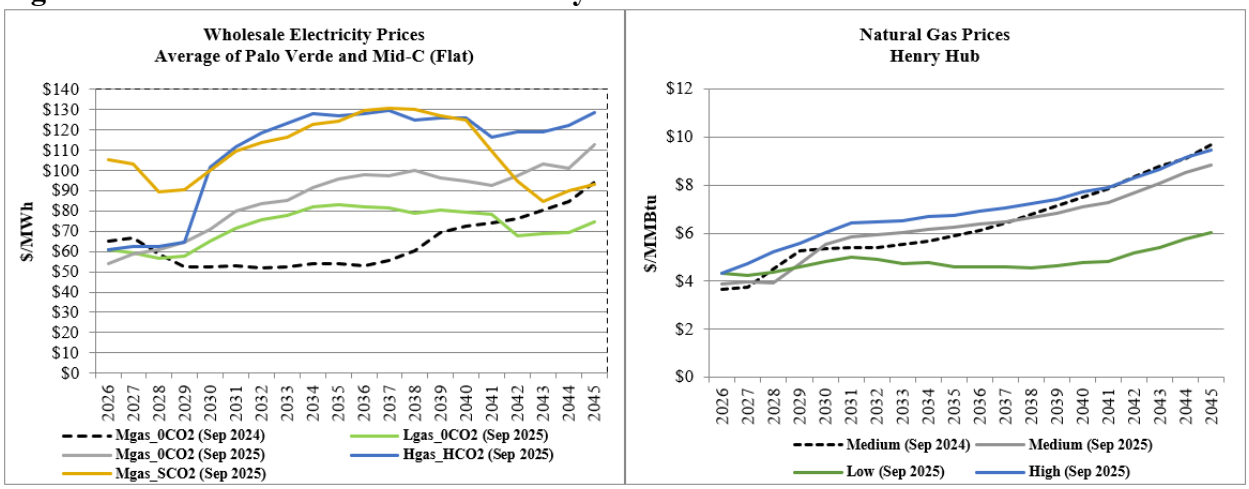
participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

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 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 include 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. The increased cost calculated for coal pricing was developed by evaluating the percentage difference in the average annual gas prices at Henry Hub between the medium and high cases. Annual percentage differences were then applied to each coal plant's coal supply price over the 20-year horizon.

Figure 5.1 summarizes the four wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2025 IRP Update.

Figure 5.1 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Carbon Dioxide Emission Policy

PacifiCorp used three different CO_2 price scenarios in the 2025 IRP Update—zero, high, and a price forecast that aligns with the social cost of greenhouse gases (SCGHG. 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.

The SCGHG scenario complies with Washington RCW 19.280.030 including an adjusted cost of greenhouse gas emissions reflecting inflation, defined by the Washington Utilities and

Transportation Commission.[8] 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 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 (CCA) passed by the Washington Legislature in 2021.[9] This is in addition to the assumed 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.[10]

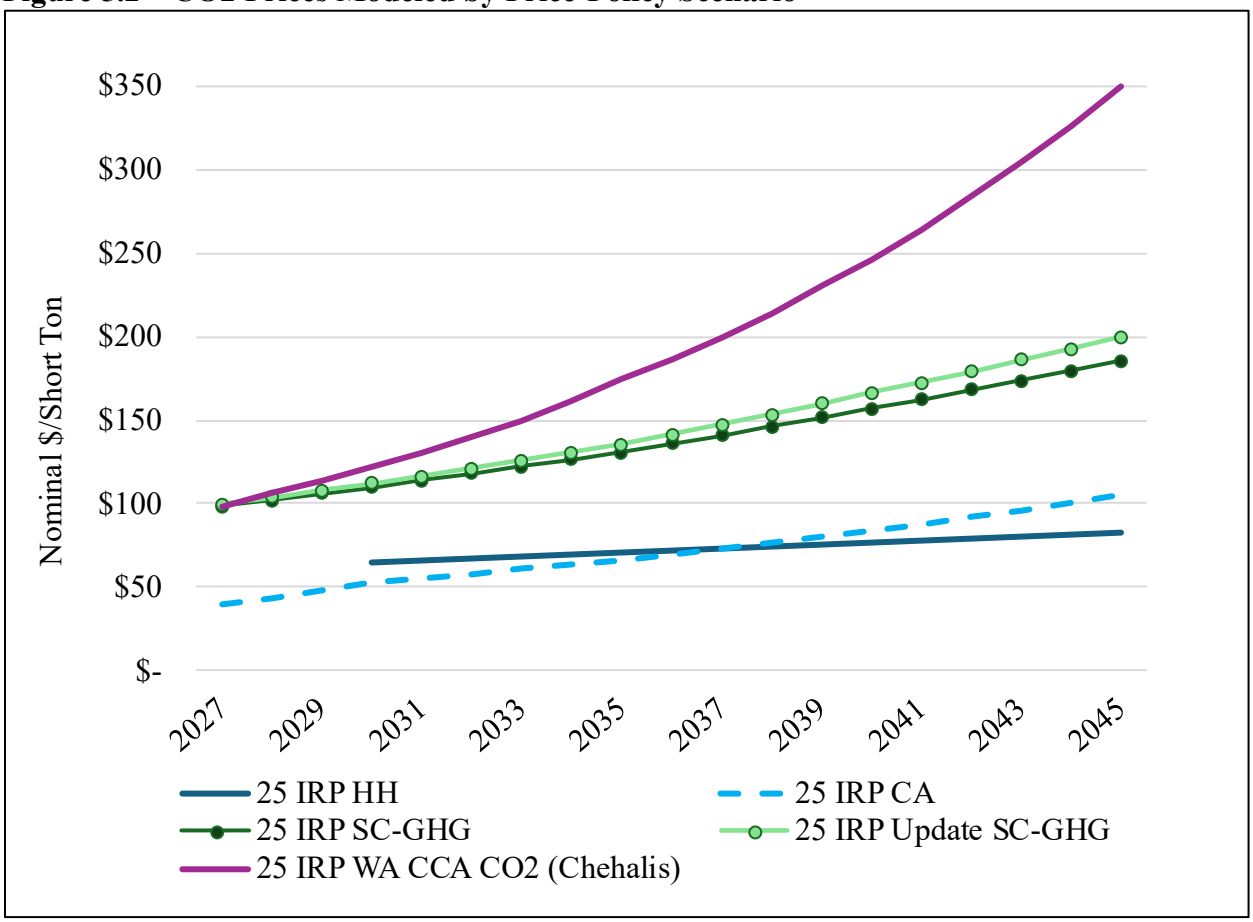
Figure 5.2 summarizes the different CO_2 price scenarios used in the 2025 IRP, along with a forecast of the Washington SC-GHG CO_2 price forecast used in the 2025 IRP Update.

[8] 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).

[9] 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).

[10] 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 5.2 – CO2 Prices Modeled by Price-Policy Scenario



Supply-Side Resources

Proxy resource costs and operating characteristics have been updated from assumptions used in the 2025 IRP in response to stakeholder comments. In the 2025 IRP, cost escalation rates for proxy resources started in 2025 but should have been applied beginning in the earliest commercial operation year for each proxy resource. This correction has been implemented for the 2025 IRP Update. Additionally, PacifiCorp has moved to using the 2024 NLR ATB construction finance factors rather than applying PacifiCorp specific adjustments for property tax, surcharge, and AFUDC. This change makes more of the underlying data for PacifiCorp's supply-side resource costs publicly available. For certain proxy resource options such as enhanced geothermal, moving to using NLR's construction finance factors has a significant impact on the estimated build cost for that resource option. Stakeholder feedback indicates that enhanced geothermal cost estimates based on the 2020 ATB are outdated.[11] In the 2025 IRP Update, PacifiCorp leveraged 2024 NLR ATB overnight capital costs for estimating build costs for supply-side resources. 2024 NLR ATB overnight capital costs are used as opposed to NLR's CAPEX costs because NLR's CAPEX costs include grid connection costs which PacifiCorp models separately from the costs of proxy supply-side resources via transmission expansion options that enable new proxy generation and storage resources.

[11] See Appendix G, stakeholder feedback form #1 (Fervo Energy).

Tax credit changes related to the One Big Beautiful Bill Act (OBBBA) were not included in the 2025 IRP as the law was not passed until July 4th, 2025, over 3 months after the final filing of the 2025 IRP. OBBBA tax credit assumptions have now been included in modeling for the 2025 IRP Update. Within the 2025 IRP Update supply-side resource table detail, all costs are presented in real levelized 2025 dollars. Depending on the assumed implementation time, proxy resources can be selected in any size and combination at any location, with hourly generation limited by available transmission. As an example, if a selected transmission upgrade allows for 400 additional megawatts of resources, the model is allowed to select 600 megawatts of wind resources, 300 megawatts of battery resources, 300 megawatts of solar resources, and 200 megawatts of gas peaking resources. This would cause the location to have 1400 megawatts of nameplate resources, of which only 400 megawatts could be generating into the system at any point in time. Any excess generation could flow into storage resources or would otherwise be curtailed. Tables 5.1-5.3 present the proxy supply-side resource costs for proxy resource in the 2025 IRP Update. Additional details on the costs and characteristics of proxy supply-side resources are presented in Appendix C.

Supply-Side Table Column Headers:

Column headers for Table 5.1 (below) are defined as follows:

- Resource Description: A brief description of the primary fuel or source used for electricity generation or storage.
- Modeled IRP: A “yes/no indicator signaling whether a given resource option from the supply-side table was modeled in PLEXOS and available for selection.
- Availability Year: The year when a given resource option is available for generation and dispatch.
- Asset Life (yrs): The average number of years a given resource option is expected to be "used and useful.”
- Total Fixed Cost ($/kW-yr): A sum of the fixed costs for a given resource option which includes fixed operation and maintenance (O&M) costs, demolition costs and build costs.
- Total Fixed Cost ($/MWh): A conversion of the total fixed cost in dollars per kilowatt-year to dollars per megawatt-hour. The total fixed cost in dollars per megawatt-hour also applies the assumed capacity factor for each resource option.
- Total Resource Cost ($/MWh): A sum of fixed costs, fuel costs and variable operations and maintenance costs (VOM) in dollars per megawatt-hour. Total resource cost is presented without tax credits applied for eligible resource options. For storage resources, fuel costs do not include the costs associated with charging storage resources.

Table 5.1 - 2025 IRP Update Supply Side Resources (2025$)[12]

Resource Description	Modeled IRP	Availability Year	Asset Life (yrs)	Total Fixed Cost ($/kW-yr)	Total Fixed Cost ($/MWh)	Total Resource Cost ($/MWh)
Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	Yes	2032	30	$202.34	$24.97	$390.74
SCCT Aero, with SCR	No	2032	40	$177.19	$61.30	$122.81
SCCT Aero x4, with SCR	No	2032	40	$123.85	$42.84	$102.66
SCCT Frame "F" x1, with SCR	Yes	2032	40	$120.22	$41.59	$105.99
Goshen*	Yes	2032	40	$240.37	$83.15	$148.25
Wasatch Front	Yes	2032	40	$137.68	$47.63	$112.75
Wyoming East	Yes	2032	40	$151.42	$52.38	$109.70
CCCT Dry "H", 1X1, DF, with SCR	Yes	2033	40	$171.11	$25.04	$62.39
Goshen*	Yes	2033	40	$248.70	$36.40	$74.49
Wasatch Front	Yes	2033	40	$181.74	$26.60	$64.77
Wyoming East	Yes	2033	40	$190.71	$27.91	$61.39
CCCT Dry "H", 2X1, DF, with SCR	Yes	2033	40	$143.10	$20.94	$58.20
Goshen*	Yes	2033	40	$221.55	$32.42	$70.43
Wasatch Front	Yes	2033	40	$154.07	$22.55	$60.64
Wyoming East	Yes	2033	40	$163.16	$23.88	$57.22
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	No	2033	40	$322.11	$47.14	$91.59
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	No	2033	40	$265.55	$38.86	$83.24
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	No	2032	30	$187.68	$64.92	$118.63
SCCT Aero, with SCR + Δ for CT Brownfield construction	No	2032	40	$161.28	$55.79	$116.45
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	No	2032	40	$112.94	$39.07	$98.21
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	Yes	2032	40	$112.17	$38.80	$102.23
Goshen-Brownfield*	No	2032	40	$232.25	$80.34	$143.44
Wasatch Front-Brownfield	Yes	2032	40	$129.72	$44.87	$108.02
Wyoming East-Brownfield	Yes	2032	40	$143.46	$49.62	$112.39
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	Yes	2033	40	$160.14	$23.44	$60.44
Goshen-Brownfield*	No	2033	40	$237.62	$34.78	$71.88
Wasatch Front-Brownfield	Yes	2033	40	$170.88	$25.01	$62.22
Wyoming East-Brownfield	Yes	2033	40	$179.85	$26.32	$63.53
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	Yes	2033	40	$133.89	$19.60	$56.57
Goshen-Brownfield*	No	2033	40	$212.25	$31.06	$68.14
Wasatch Front-Brownfield	Yes	2033	40	$144.95	$21.21	$58.39
Wyoming East-Brownfield	Yes	2033	40	$154.05	$22.54	$59.72
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	No	2033	40	$301.64	$44.15	$87.94
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	No	2033	40	$248.69	$36.40	$80.18
SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	No	2032	40	$124.82	$43.18	$109.06
CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	No	2033	40	$174.86	$25.59	$63.46
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	No	2033	40	$146.23	$21.40	$59.09
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	2032	40	$284.15	$98.29	$163.19
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	2033	40	$346.42	$50.70	$88.54
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	2033	40	$310.01	$45.37	$83.12
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	2032	40	$245.77	$85.02	$150.08
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	2033	40	$308.38	$45.13	$83.14
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	2033	40	$271.87	$39.79	$77.70
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	No	2033	40	$169.07	$24.74	$62.07
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	No	2033	40	$139.40	$20.40	$57.60
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1 with 95% CCS	No	2033	40	$305.30	$44.68	$88.77
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1 with 95% CCS	No	2033	40	$245.26	$35.89	$79.86
Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer	Yes	2033	40	$198.35	$23.10	$23.10
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	No	2030	40	$36.96	$4.35	$28.26
CCS Dave Johnston 4 (costs on post retrofit basis)	No	2032	30	$592.72	$79.60	$92.31
CCS Hunter 1-3 (costs on post retrofit basis)	No	2032	30	$501.99	$67.42	$78.27
CCS Huntington 1&2 (costs on post retrofit basis)	No	2032	30	$510.86	$68.61	$79.35
CCS Jim Bridger 3&4 (costs on post retrofit basis)	Yes	2031	30	$497.79	$66.85	$78.64
CCS Wyodak (costs on post retrofit basis)	No	2032	30	$634.62	$85.23	$98.26

[12] The "*" by proxy gas resource options in Goshen indicates that while the Goshen locational cost modifier has been applied to PLEXOS resource options for proxy gas resource options near Goshen in PacifiCorp's IRP topology bubble, no proxy gas resource options are available at the Goshen IRP topology bubble in PacifiCorp's 2025 IRP Update. This is due to the lack of availability of existing gas pipelines to serve a new gas resource in the Goshen IRP topology bubble.

Table 5.1 - 2025 IRP Update Supply Side Resources (2025$) (continued)

Resource Description	Modeled IRP	Availability Year	Asset Life (yrs)	Total Fixed Cost ($/kW-yr)	Total Fixed Cost ($/MWh)	Total Resource Cost ($/MWh)
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	Yes	2035	60	$713.57	$87.59	$91.03
Goshen	Yes	2035	60	$722.61	$88.70	$92.14
Wasatch Front	Yes	2035	60	$722.61	$88.70	$92.14
Wyoming East	Yes	2035	60	$709.05	$87.03	$90.48
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	No	2034	60	$464.73	$57.04	$59.89
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	No	2035	60	$784.84	$96.34	$100.12
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	No	2034	60	$511.14	$62.74	$65.88
Large Light Water Reactor, Moderate Technology Case	No	2037	60	$571.38	$70.14	$79.52
Large Light Water Reactor, Advanced Technology Case	No	2035	60	$447.07	$54.88	$62.76
Near Field Enhanhanced Geothermal System (NF-EGS) Binary	Yes	2028	30	$1,032.89	$147.39	$147.39
Southern OR	Yes	2028	30	$1,166.65	$166.47	$166.47
Wasatch Front	Yes	2028	30	$1,032.89	$147.39	$147.39
Near Field Enhanhanced Geothermal System (NF-EGS) Binary Low Cost	Yes	2028	30	$812.44	$115.93	$115.93
Li-Ion, 4-hour, 20 MW	No	2026	20	$170.57	$116.83	$116.83
Li-Ion, 4-hour, 200 MW	Yes	2027	20	$139.57	$95.60	$95.60
Portland North Coast	Yes	2027	20	$145.16	$99.43	$99.43
Southern OR	Yes	2027	20	$147.03	$100.70	$100.70
Walla Walla	Yes	2027	20	$142.37	$97.51	$97.51
Goshen	Yes	2027	20	$141.44	$96.87	$96.87
Wasatch Front	Yes	2027	20	$125.96	$86.28	$86.28
Wyoming East	Yes	2027	20	$122.86	$84.15	$84.15
Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW	Yes	2027	20	$230.92	$79.08	$79.08
Portland North Coast	Yes	2027	20	$239.86	$82.14	$82.14
Southern OR	Yes	2027	20	$242.84	$83.16	$83.16
Walla Walla	Yes	2027	20	$235.39	$80.61	$80.61
Goshen	Yes	2027	20	$233.90	$80.10	$80.10
Wasatch Front	Yes	2027	20	$209.14	$71.62	$71.62
Wyoming East	Yes	2027	20	$204.19	$69.93	$69.93
Li-Ion, 4-hour, 1000 MW	No	2028	20	$144.13	$98.72	$98.72
Gravity Battery, 4-hour, 1000 MW	Yes	2028	50	$116.43	$79.74	$79.74
Wasatch Front	Yes	2028	50	$118.20	$80.96	$80.96
Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	No	2028	50	$196.83	$67.41	$67.41
Adiabatic CAES, 500 MW, 4000 MWh	No	2028	50	$184.94	$63.34	$65.94
100-hour Iron Air	Yes	2030	20	$165.17	$62.71	$62.71
Portland North Coast	Yes	2030	20	$200.84	$76.24	$76.24
Wasatch Front	Yes	2030	20	$168.98	$64.15	$64.15
Pumped Hydro, Two New Reservoirs, 4-hour	No	2030	100	$122.43	$83.85	$84.43
Pumped Hydro, Two New Reservoirs, 10-hour	Yes	2030	100	$182.63	$50.04	$50.73
Portland North Coast	Yes	2030	100	$191.45	$52.45	$53.14
Southern OR	Yes	2030	100	$194.39	$53.26	$53.95
Goshen	Yes	2030	100	$185.57	$50.84	$51.53
Wasatch Front	Yes	2030	100	$159.78	$43.78	$44.47
Wyoming East	Yes	2030	100	$154.92	$42.44	$43.13
Pumped Hydro, One New Reservoir, 4-hour	No	2030	100	$119.12	$81.59	$82.17
Pumped Hydro, One New Reservoir, 10-hour	No	2030	100	$159.69	$43.75	$44.44
Pumped Thermal Energy Storage, 10-hour	No	2031	60	$212.01	$68.21	$68.91
Pumped Thermal Energy Storage, 24-hour	No	2031	60	$390.72	$125.70	$126.40

Table 5.1 - 2025 IRP Update Supply Side Resources (2025$) (continued)

Resource Description	Modeled IRP	Availability Year	Asset Life (yrs)	Total Fixed Cost ($/kW-yr)	Total Fixed Cost ($/MWh)	Total Resource Cost ($/MWh)
PV, 20 MW, Class 1-10	Yes	2028	25	$151.12	$63.12	$63.12
Portland North Coast	Yes	2028	25	$158.71	$73.99	$73.99
Southern OR	Yes	2028	25	$165.04	$64.32	$64.32
Walla Walla	Yes	2028	25	$153.65	$67.57	$67.57
Goshen	Yes	2028	25	$152.39	$62.60	$62.60
Wasatch Front	Yes	2028	25	$151.12	$59.50	$59.50
Wyoming East	Yes	2028	25	$151.12	$62.80	$62.80
PV, 200 MW, Class 1-10	Yes	2028	25	$121.93	$50.92	$50.92
Portland North Coast	Yes	2028	25	$127.63	$59.50	$59.50
Southern OR	Yes	2028	25	$132.38	$51.60	$51.60
Walla Walla	Yes	2028	25	$123.83	$54.45	$54.45
Goshen	Yes	2028	25	$122.88	$50.47	$50.47
Wasatch Front	Yes	2028	25	$121.93	$48.00	$48.00
Wyoming East	Yes	2028	25	$121.93	$50.67	$50.67
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	2028	25	$141.36	$59.04	$59.04
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	2028	25	$114.17	$47.68	$47.68
Wind Class 1-10, 20 MW	Yes	2028	30	$243.13	$95.07	$95.07
Portland North Coast	Yes	2028	30	$263.74	$120.85	$120.85
Southern OR	Yes	2028	30	$276.85	$125.49	$125.49
Walla Walla	Yes	2028	30	$250.62	$123.70	$123.70
Goshen	Yes	2028	30	$246.88	$93.08	$93.08
Wasatch Front	Yes	2028	30	$245.00	$91.95	$91.95
Wyoming East	Yes	2028	30	$239.38	$66.25	$66.25
Wind Class 1-6, 200 MW	Yes	2030	30	$142.35	$47.61	$47.61
Portland North Coast	Yes	2030	30	$152.82	$46.37	$46.37
Southern OR	Yes	2030	30	$159.48	$53.45	$53.45
Walla Walla	Yes	2030	30	$146.16	$51.20	$51.20
Goshen	Yes	2030	30	$144.25	$54.38	$54.38
Wasatch Front	Yes	2030	30	$143.30	$53.78	$53.78
Wyoming East	Yes	2030	30	$140.44	$40.28	$40.28
Wind Class 7, 200 MW	No	2030	30	$147.04	$48.84	$48.84
Offshore, Wind Class 12	Yes	2032	30	$434.22	$159.81	$159.81
Southern OR	Yes	2032	30	$490.83	$114.48	$114.48
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	No	2028	30	$228.89	$89.50	$89.50
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	No	2030	30	$133.32	$44.28	$44.28
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	No	2030	30	$137.79	$45.77	$45.77
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	No	2032	30	$318.06	$43.00	$43.00

Demand Side Management

PacifiCorp evaluates new demand side management (DSM) opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. The optimal determination of DSM resources therefore results in the selection of cost-effective DSM as a core function of IRP modeling. As in the 2025 IRP, DSM for Washington in the 2025 IRP Update preferred portfolio reflects selections from the Washington compliance scenario, under SC-GHG price-policy assumptions. In the 2025 IRP Update, energy efficiency shapes for heating and cooling measures have been updated to align with updated load, representing the relative effectiveness of these bundles to meet system needs.

Modeling Enhancements and Resource Update

Transmission Option Updates

In the 2025 IRP Update, transmission projects do not have to be selected as one unit or zero units but can be selected in any size from zero to 100% of a line. In practice, this means that if the model deems it most economic to build 25% of a local area upgrade in 2033, the model can choose to build another 30% in 2034 and the remaining 45% of the line can remain unbuilt. For local area upgrades, this correlates more closely to real world cluster project transmission and funding where (as an example) 30% of the cluster chooses to move forward and the balance withdraws. When considering incremental lines, given the far future timelines for those items, this modeling provides appropriate flexibility considering permitting nuances and the complex nature of transmission approvals. Selection of a portion of an incremental transmission line in the distant future signals that this transmission option has value to the system and warrants further study to determine the best sizing and timing of the line. Further engagement with stakeholders regarding transmission modeling methodology will occur in the 2027 IRP public input meetings series.

Other Contracts

PacifiCorp continually updates and negotiates with contracted facilities. The most current contracted resources, as of January 1, 2026, are being used for the 2025 IRP Update. Given timing, this is the last update to contracted resources that will be made for the Update. Between the 2025 IRP and the 2025 IRP Update, PacifiCorp has signed an additional nine megawatts of small Oregon Community Solar Projects that will be reflected in the 2025 IRP Update.

As an original purchaser of the output of the Priest Rapids and Wanapum hydro projects, PacifiCorp has an annual option to purchase approximately 100 megawatts of the output from these hydro plants at market-based rates. Current contract quantities as of January 1, 2026, are reflected for these purchases in all years in the 2025 IRP Update.

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CHAPTER 6 – MODELING METHODOLOGY

Introduction

PacifiCorp used two PLEXOS optimization models to develop an updated preferred portfolio[1,2] based on key changes that have changed since the 2025 Integrated Resource Plan (IRP). This chapter describes the technical means for arriving at the best available portfolio leading ultimately to the selection of the preferred portfolio. The primary factors for evaluation include key updates to data, methodologies and assumptions. Such changes can come from a variety of sources, and may be driven policy, such as the federal government's Big Beautiful Bill, updated fundamentals such as pricing and load forecasts, requests from stakeholders, or changes to regulatory requirements stemming from laws and commission orders.

Updates

Key Updates and Methodological Changes

PacifiCorp implemented a number of updates and modeling changes due to new federal policies, updates to pricing, and stakeholder feedback. Changes, which are further detailed below, include:

- Impacts related to the One Big Beautiful Bill Act (OBBBA)
- Changes in load and price curves
- Changes to proxy resource costs
- Implementation of sampled LT chronology
    - Corresponding updates to reliability load addition process to align with sampled methodology
- A system level resource adequacy run[3]
- Removal of deliverability requirement for Oregon and Washington *energy* compliance

As discussed in Chapter 5, key input changes in this 2025 IRP Update are driven by the updated tax credit treatment resulting from the OBBBA, ongoing resource acquisition strategy, forecast load demand, supply-side resource cost updates, and updates to coal, natural gas, and wholesale power market price updates.

The first of these items, the tax credit implications of the OBBBA on new resources, is particularly impactful on the system as a whole. Since the time the 2025 IRP inputs were finalized, the United States Congress passed the OBBBA, which made significant changes to tax credit eligibility for

[1] (From Appendix Z). Portfolio: a coordinated set of resources (including generation, demand-side management, storage, purchases and transmission) which meet all modeled requirements for a given set of conditions. Portfolios result from running models which employ advanced math to make optimal resource selections aligned with the specified conditions.
2 (From Appendix Z). Preferred portfolio: the optimal portfolio, selected from among eligible portfolios, based on cost and risk metrics.
[3] See Appendix G, stakeholder feedback form #19 (Sierra Club, et al.). See also Appendix G, stakeholder feedback form #20 (Public Utility Commission of Oregon).

new renewable and storage resources. Production tax credits for wind and solar resources will be going away for any projects that have not begun construction by the end of 2025. In the 2025 IRP Update, this means that no proxy wind and solar resources are assumed to be eligible to receive production tax credits. Investment tax credits remain available for storage, geothermal, nuclear and carbon capture and sequestration projects. In the 2025 IRP Update, 2037 is the last year of tax credit eligibility for proxy storage, geothermal, and nuclear resources. The phaseout of new tax credits increases the cost of proxy resources.

Other Updates

In addition to the key updates noted above, the 2025 IRP Update includes conventional planning updates where data has changed following PacifiCorp's filed 2025 IRP. This includes updates to the load forecast, market prices, changes in existing resources, new resource adequacy requirements consistent with the Western Resource Adequacy Program (WRAP), and PacifiCorp's contracts with other entities.[4]

Coal and gas plants are eligible to be retired any time after January 1, 2029. This serves to standardize assumptions and allows the model to indicate if any retirements are economic for the system.

Large-Meter Load Considerations

The treatment of large-meter loads (LML) in the 2025 IRP Update builds upon the approach applied in the 2025 IRP. The 2025 IRP is represented by indicator "A" in Figure 6.1, below, where no new LML was modeled. Also in the 2025 IRP, the company prepared an "All-in" bookend study representing all potential LML known at the time of the study. The "all-in" study is represented by indicator "E" in Figure 6.1.

For the 2025 IRP Update, the preferred portfolio is initially developed assuming only existing contracts, consistent with the 2025 IRP (Indicator "A", below). Once this stage of the portfolio was developed, portfolio selections were locked. The preferred portfolio was then completed by adding new committed[5] near-term data center load and corresponding resources. This approach is indicated as "B" in Figure 6.1.

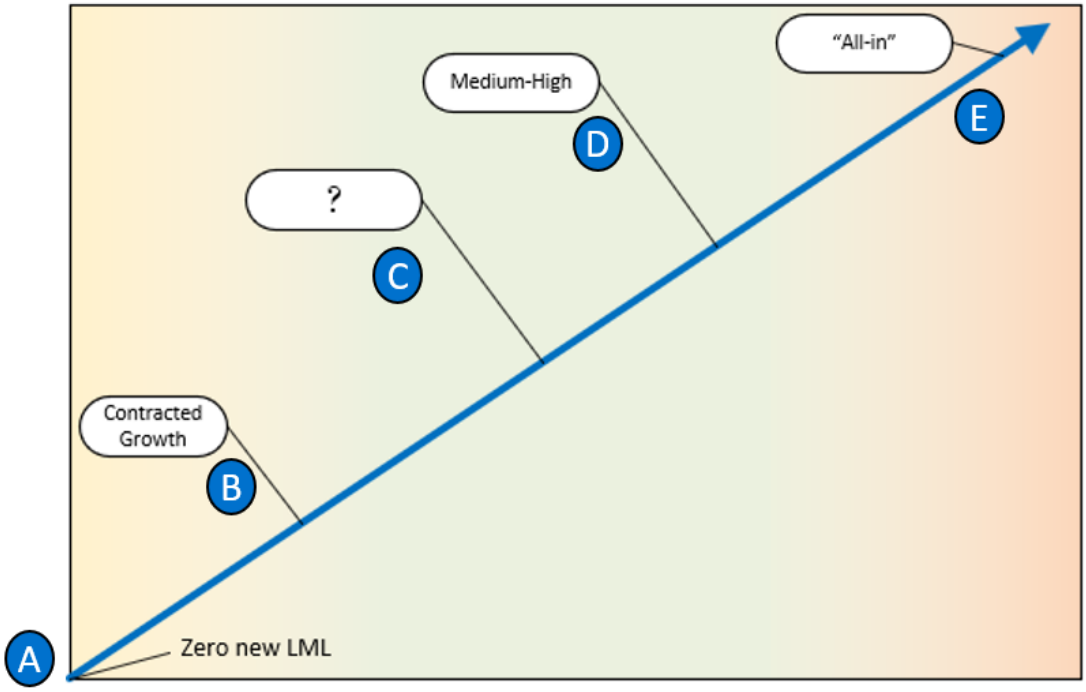
For the 2027 IRP, PacifiCorp proposes two additional sensitivities based on future forecasting. As forecasts, these studies are distinct from the bookend approach used in the 2025 IRP and 2025 IRP Update. The most difficult forecast will be "C", below, for which a forecasting strategy has not yet been developed. This forecast will attempt to quantify expected LML that has a factual basis specifically for PacifiCorp, taking into account the challenges of inaccurate estimates provided by customers, requests submitted to multiple utilities, unserious requests, and heavy flux in the planning environment.

[4] See Appendix G, stakeholder feedback form #4 (Sierra Club, et al.)
[5] The definition of a "committed" resource has been refined since the 2025 IRP and is given in Appendix Z. For convenience, the operational definition of "committed" is "Something that PacifiCorp Energy Supply Management is obligated to serve". See also Appendix G, stakeholder feedback forms, 5, 12 and 15.

The last proposed study is labeled "D" below and is similar to "C" with the exception of intentionally aiming high. This forecast attempts to represent the upper limit of what PacifiCorp may expect as a subset of all of the potential LML represented in the "All-in" bookend study.

PacifiCorp is open to alternative strategies for appropriately forecasting large loads and has continued to discuss this challenge with stakeholders in the 2027 IRP public input process. The company encourages interested parties to review the reasons for limited inclusion of large loads as detailed in the 2027 IRP public input meeting series.[6,7]

Figure 6.1 – Proposed Large-Meter Load Growth Studies for the 2027 IRP



Portfolio Development Overview

PacifiCorp has made a variety of adjustments to modeling methodology for use in the 2025 IRP Update. Some of these are in response to stakeholder feedback, while others have been developed in concert with Energy Exemplar, the PLEXOS software vendor.

[6] PacifiCorp IRP January 28-29, 2026 Public Input Meeting materials, pp. 9-12
[7] See Appendix G, stakeholder feedback form #4 (Sierra Club, et al.). Also see Appendix G, stakeholder feedback form #20 (Public Utility Commission of Oregon)

PLEXOS Chronology Background

In response to stakeholder feedback, PacifiCorp explored changing the LT model chronology from 4 blocks per month to a sampled days chronology. In the 2025 IRP, PacifiCorp used partial chronology in the LT model. This meant that the LT model grouped similar hours into a block, calculated the average load and resource parameters specific to each block, and then concurrently solved the entire modeling horizon. When using sampled chronology, the LT model first dispatches the set of days that best capture the annual variation in the load forecast. This set of days can either be selected directly by PLEXOS or fed into the model as an input. In addition to dispatching the set of days, PLEXOS uses the load forecast to identify, for each of the 365 days in a year, which of the selected sampled days best represents its pattern. As an example, if July 21st, 2026, is one of the sampled days that is dispatched by the model, PLEXOS may decide that July 21st is the best match among the sampled days for the load pattern on July 22nd, 2026. Since the load on July 22nd may be lower or higher than the load on July 21st, when representing July 22nd, PLEXOS scales the data from July 21st to mimic the load forecast for July 22nd.

Sampled chronology more accurately represents the hourly granularity of the load forecast within the limited granularity of the LT model compared to the partial chronology PacifiCorp previously used. However, sampled chronology distorts other model inputs, particularly renewable shapes. The model does not scale the renewable dispatch from sampled days to mimic the annual shape. So, if the 12 sampled days used in 2026 have an average capacity factor of 15% for Wyoming East wind, then the average capacity factor for the entire year will only be 15%. In the 2025 IRP Update, PacifiCorp used the sampled days selected by PLEXOS, which do not adjust for this distortion in renewable shapes. PacifiCorp is currently exploring alternate methods for selecting sampled days which consider the distortion in renewable shapes as well as load and may update its approach in the 2027 IRP.

PLEXOS Chronology Testing

Initially, PacifiCorp tested a range of sampled days from 8 to 14 days per year, stepping up in increments of 2 days. PacifiCorp also tested using blocks within each sample day, either having the model select 8 (3 hour) blocks, or having the model select 12 (2 hour) blocks for each sampled day. In this way, PacifiCorp was able to evaluate model results and run-times over 8 different variations of sampled chronology.

Ultimately, for most studies, using 12 sampled days per year with 12 (2-hour) blocks per sampled day produced the lowest-cost, most reliable portfolios using a lower number of iterations while maintaining LT model runtimes that were reasonable. As a result, PacifiCorp elected to move forward with this setup. Because PacifiCorp uses an iterative process, to ensure each subsequent iteration leveraged the same information and sample days, once the model selected the 12 sample days per year, PacifiCorp locked those days for all subsequent iterations.

While using sampled chronology produced reasonable results and runtimes for the systemwide and Washington jurisdictional studies—the Oregon sampled runs began to show persistent infeasibilities and long runtimes after corrections and adjustments were made following the 2025 IRP Update draft filing. PacifiCorp worked with Energy Exemplar throughout January and February to diagnose and resolve these issues and was eventually able to complete sufficient

phases of iteration for the Base MN Oregon jurisdictional study. PacifiCorp determined that the prudent course of action was to use partial chronology for the remaining Oregon model runs. As previously described, PacifiCorp has observed only minimal differences in resource selection as a result of changing model chronology.

Final PLEXOS Chronology

UIWC Study Name	Chronology used
Base MN	12 day/year Sampled
Base HH	12 day/year Sampled
Base LN	12 day/year Sampled
Hunter Retire	12 day/year Sampled
All Coal Retire	12 day/year Sampled
No Natrium	12 day/year Sampled
No Future Technology	12 day/year Sampled
B2H Redirects	12 day/year Sampled

Washington CETA Study Name	Chronology used
Base SC	12 day/year Sampled
No Natrium	12 day/year Sampled
No Future Technology	12 day/year Sampled
B2H Redirects	12 day/year Sampled

Oregon Study Name	Chronology used
Base MN	12 day/year Sampled
Base HH	4 Blocks per Month
Base LN	4 Blocks per Month
No Natrium	4 Blocks per Month
No Future Technology	4 Blocks per Month
B2H Redirects	4 Blocks per Month
No HB 2021	12 day/year Sampled

System-Level Resource Adequacy Run[8,9]

Stakeholders expressed an interest in seeing the portfolio that would be selected for the system as a whole if resource adequacy constraints were implemented on a systemwide basis. To accommodate this request, PacifiCorp created a system resource adequacy constraint requiring that system firm capacity be no less than system load plus a planning reserve margin. PacifiCorp did not impose any locational constraints related to resource adequacy for this model run. No preference is given to a resource that would help any individual jurisdiction meet a requirement such as emissions reductions or renewable energy generation. This model run serves as a baseline

[8] OR LC-85 Order # 26-054. Item 3.a.i. "Present a resource acquisition plan that addresses system reliability as well as state-specific needs…" pg. 2

[9] See Appendix G, stakeholder feedback form #3 (Public Utility Commission of Oregon). Also see Appendix G, stakeholder feedback form #20 (Public Utility Commission of Oregon)

to identify the lowest-cost portfolio of resources that meets system-level resource adequacy requirements in the absence of any state regulations. Therefore, this model does not account for Oregon or Washington state policies.

Change to Deliverability Considerations

In the 2025 IRP, resource additions were only eligible for compliance with Oregon HB 2021 and Washington CETA requirements if they were located in PACW. In the 2025 IRP Update, this requirement is removed. Proxy resources that are located in PACE are eligible to contribute towards HB 2021 and CETA requirements. However, consistent with the 2025 IRP, only PACW proxy resources are eligible to count towards Oregon and Washington resource adequacy.

Emissions Methodology

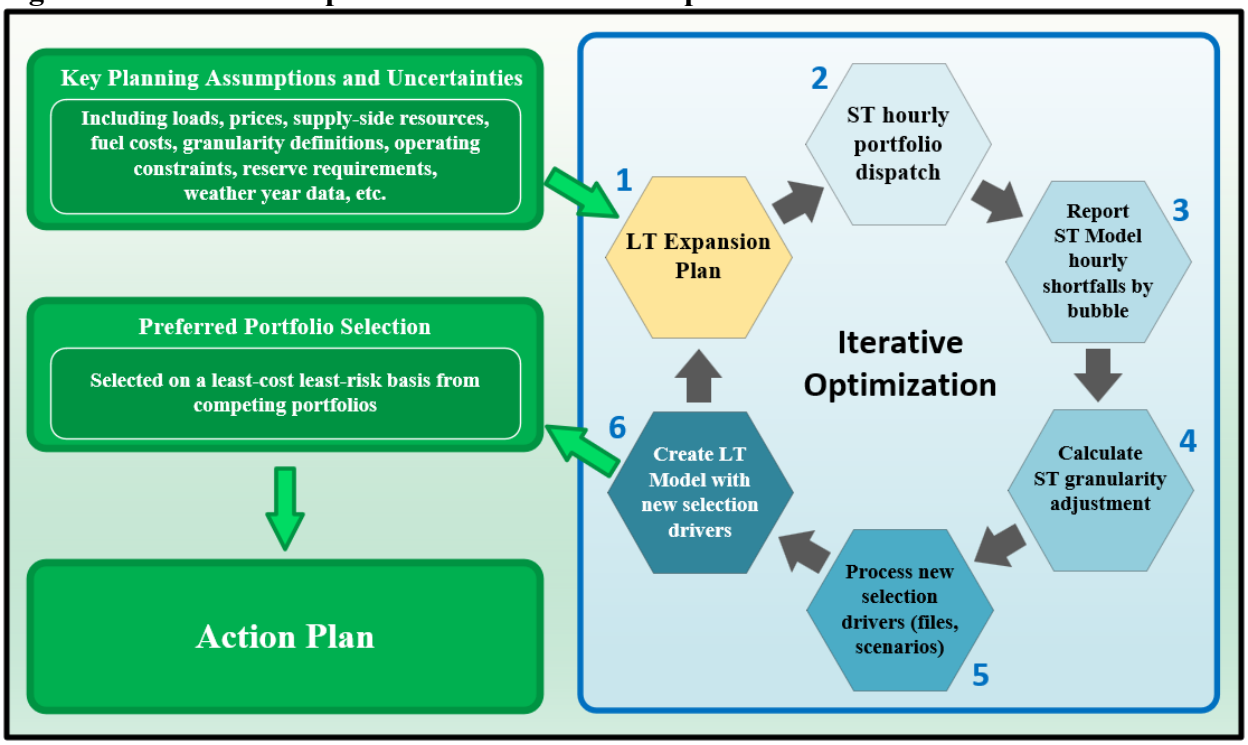
Rather than enforce a hard cap via a modeling constraint, PacifiCorp is using a price to disincentivize the model from dispatching emitting resources above regulatory requirements. In the ST model, annual constraints are not always sufficiently bound or reasonably parsed into weekly targets. In practice, this leads to emission budgets which may mis-allocate generation into a period where other, non- or lower-emitting resources may be available for dispatch. State-level requirements also impute emissions or penalize PacifiCorp based on energy shortages, which cannot be adequately included in an emission constraint.

Stakeholders have requested that PacifiCorp complete studies using PLEXOS emissions constraints. For the 2025 IRP Update, PacifiCorp is unable to complete testing and provide vetted results of various methodologies to stakeholders for review. As such, in order to be consistent with the 2025 IRP, the 2025 IRP Update is using the same methodology as in the 2025 IRP. PacifiCorp does plan to provide a comparative dispatch and compliance position for stakeholder review as part of the 2027 IRP process.

Iterative Process

In the 2025 IRP Update, PacifiCorp used the same iterative process as the 2025 IRP for developing candidate portfolios. Each iteration in the portfolio process represents one “phase,” and each phase consists of six steps. Figure 6.2 illustrates the six cyclical steps in this new process, followed by an overview and detailed description of these steps. Completion of all six steps of this process constitutes a single phase of a study.

Figure 6.2 – The Six Steps of One Portfolio Development Phase



Overview of Steps

Step 1

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

Step 2

The LT model expansion plan is fed into the short-term (ST) model. The ST model performs an hourly dispatch of the portfolio.

Step 3

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

Step 4

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

Step 5

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

Step 6

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

Granularity Adjustment Detail

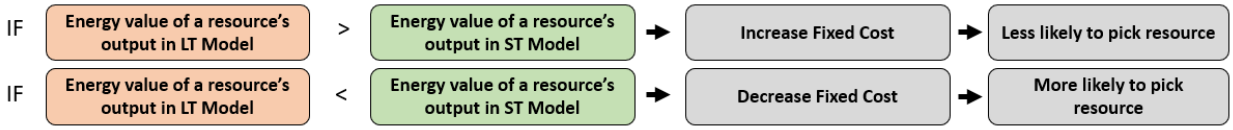
The capacity expansion/LT and ST models in PLEXOS each run and solve using a different view of the study horizon. The LT model in the 2025 IRP used a blocked chronology method where 4 blocks of hours were grouped together in each month over a 21 year horizon. For the Update, the LT model uses 12 sampled days per year over a 20 year horizon. In contrast, the ST model concurrently dispatches each week of each year, or 52 steps of 168 hours each, given a specified portfolio of resources selected in the LT model. In the sampled LT view, a resource is seen as having a certain amount of value to the system in the 144 periods it evaluates during each year (12 sample days times 12 blocks per sampled day). When the ST model dispatches those same resources at an hourly granularity, the ST model also reports the value it calculates for each resource on an annual basis. The mathematical difference between the value of a resource in the ST and in the LT is the granularity adjustment.

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

A new granularity adjustment is calculated for every portfolio and variant developed and for each run of an iteration, rather than using one granularity adjustment calculated for each price-policy scenario.

Figure 6.3 illustrates the calculation of the granularity adjustment, which is completely derived from ST and LT model outputs. A distinct granularity adjustment is calculated for every individual resource in each year of every phase of every study.

Figure 6.3 – 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

While granularity adjustments are included as an increase or decrease in fixed costs, reliability adjustments are 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 added to the LT need as further detailed below. The change from using a partial blocked chronology to using a sampled chronology led to methodological changes. ST studies are always run with the base load forecast to verify whether LT additions were sufficient to eliminate shortfalls in all hours. However, the adjusted load file used in the LT model to select a reliable portfolio continues to be applied in each consecutive

phase 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.

Moving to sampled chronology required a change in the methodology for adding shortfalls identified in the ST model to the LT model Shortfalls can occur on any day of the horizon in the ST and often are present on days that are not one of the 12 sampled days used in the LT model. If shortfalls identified on a given day in the ST model were directly added to the same day in the LT model load forecast, most of these shortfalls would not be adequately "seen" by the model because they would fall outside of the 12 sampled days. As a result, PacifiCorp determined instead to apply the peak hourly shortfall in any given year to the peak sampled days in the summer and the winter. This peak shortfall is then increased by 75% so that the model continues to add resources for reliability as it iterates through progressive phases.

As an example, the model could see shortfalls in the year 2030 in the "Central OR" topology bubble. Instead of adding every shortfall hour for hour, PacifiCorp takes the highest shortfall in that year and applies that shortfall to the most load-constrained days of that year as additional load in Central OR. Adding it in this way guarantees that the LT model will continue to build to cover the times additional resources are required.

These changes in the application of reliability and granularity adjustments support the iterative process that loops from the LT model to the ST model and back to the LT model. The process is considered complete once portfolios are reliable and the present value revenue requirement (PVRR) of reliable portfolios report changes within a small range.

Resource Adequacy

Similarly to the 2025 IRP, resource adequacy is modeled using qualifying capacity contributions and planning reserve requirements consistent with data provided by the Western Resource Adequacy Program (WRAP). Although PacifiCorp has elected not to commit to binding WRAP participation, use of WRAP contribution factors is still an appropriate proxy for utilities within the broader western footprint. As discussed above, responsive to stakeholder feedback, PacifiCorp has implemented an additional model run which enforces a system resource adequacy constraint. As in the 2025 IRP, PacifiCorp completes jurisdictional model runs which enforce resource adequacy constraints that are specific to the appropriate jurisdiction.

Stochastic Analysis

Consistent with 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, using historical data based on 2015, 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, random 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).

The stochastic model runs shock each hour of data based on the relative historical variation in that hour of the representative year. As an example, if the load at noon on January 1, 2013, was 15% higher than the representative load for that hour in the load forecast, each of the 20 standard load forecast January 1 noon hours is multiplied by 1.15 for the 2013 stochastic simulation.

End Effects Mitigation

"End effects" are distortions that occur in the output of long-term planning models due to simulating an infinite future as a fixed time-span. Optimization models natively operate as if time stops at the end of the fixed horizon, which is the year 2045 in the 2025 IRP Update. The distortion in outcomes results from several factors, a key component of which is disregarding post-horizon costs and value. End effects can be mitigated through various means including the mathematical extension of the later years of analysis. This has the effect of more heavily weighting a model's end-state on an annualized basis and accounting for the time-value of money.

In the 2025 IRP Update, end effects mitigation will be applied to all portfolios based on the MN stochastic risk adjusted PVRR. This is consistent with the approach used in the 2025 IRP. Applying end effects allows PacifiCorp to review the long tail of significant investment choices which have useful lives long past the 20-year window of the IRP. Assessing end effects allows PacifiCorp to mitigate the potential for outsized costs or benefits in early years from outweighing the late-term performance of a portfolio.

Stakeholders have expressed concerns regarding the mitigation of end effects[10], but appear supportive of exploring the topic further in the 2027 IRP.[11] End effects mitigation strategies can become highly complex and far-reaching. PacifiCorp's application of end effects mitigation is limited and conservative. The current intention is that future IRP analysis will continue to include some form of mitigation and the company welcomes further discussion and feedback in the ongoing public input meeting series.

In practice, assume two portfolios (A and B) have a total cost difference of $200 million after the risk adjustment. Further assume portfolio A is the least cost, least risk portfolio. If the final year difference between them is $500 million, this has a $146 million impact on the 20-year present value of revenue requirement for PacifiCorp investments. If portfolio A is $500 million less expensive in the final year, a consideration of end effects shows that this portfolio would continue to outperform portfolio B. However, if portfolio B were $500 million less expensive, it would be important to consider that one additional year with $500 million less cost would have a $284 million total impact on the portfolio values, suggesting that PacifiCorp should consider portfolio

[10] See Appendix G, stakeholder feedback form #4 (Sierra Club, et al.)
[11] For the 2027 IRP, a discussion of end effects mitigation is anticipated for the 2027 IRP April 22-23, 2026 public input meeting. A follow-up discussion will be included in the July 15, 2026 public input meeting which is dedicated to the review of all inputs.

B. Without applying end effects mitigation, this analysis could indicate portfolio choices which may harm customers in the long run.

The application of end effects mitigation in the 2025 IRP Update is aligned with the approach taken in the 2025 IRP. The company is committed to refining end effects mitigation with ongoing stakeholder feedback relevant to the 2027 IRP.

Integrated Portfolio Development

Integrated portfolios are the culmination of multiple iterative studies, each designed to produce a system-wide capacity expansion plan driven by each jurisdiction's requirements while adhering to all relevant constraints. The iterative study process detailed above was completed for all competitive studies in the 2025 IRP Update, placing them all on the same "playing field" for comparison while remaining faithful to each study's individual objectives. The optimal (least-cost, least-risk) integrated portfolio is then selected from among all competitive portfolios and becomes the preferred portfolio.

The preferred portfolio plays a significant role in fulfilling purposes of the 2025 Update as outlined in Chapter 1. The preferred portfolio looks backward to the full 2025 IRP with regard to marking new or ongoing trends and it also looks forward to provide substance for discussion in the forthcoming 2027 IRP. By incorporating key changes to inputs and assumptions driven by stakeholder interest and the planning environment, the updated preferred portfolio is not designed to be a complete re-evaluation of each detail of the previous preferred portfolio but rather provides insight into where future activity may lead.

PacifiCorp has received feedback stemming from the 2025 IRP regarding desired enhancements to the jurisdictional integration approach.[12,13] Changes in the 2025 IRP Update are limited due to the need for broader feedback, time and resource constraints, and the need to maintain reasonable alignment with 2025 IRP methodologies for comparison purposes. However, please also see the section "Systemwide Portfolio" below, which accommodates a significant component of the requested modeling changes.

Under ordinary circumstances, the least-cost least-risk portfolio is the one developed under "expected case" conditions. For the 2025 IRP and this Update, the expected case portfolio is the one which assumes a medium natural gas forward price curve and no additional carbon price driver. This expected case is designated "MN" representing medium gas and "no" *new* CO_2 adder.[14] The reason no *new* CO_2 adder is currently anticipated is because jurisdictions have already passed legislation defining expected future conditions, and the federal government is currently engaged in a trend to reduce emissions restrictions and to reduce or eliminate programs which encourage the development of renewables.

[12] See Appendix G, stakeholder feedback form #2 (Sierra Club, et al.)
[13] See Appendix G, stakeholder feedback form #9 (Sierra Club, et al.)
[14] Capacity expansion selections for the state of Washington are selected under the SC-GHG price-policy scenario to align with regulatory requirements. See appendix E for additional information regarding Washington regulatory obligations.

Jurisdictional Integrity

Each of the three identified jurisdictions is unique and requires distinct consideration. While Oregon and Washington rely on their own jurisdictional analysis due to regulatory requirements and practical modeling considerations, the other states (Utah, Idaho, Wyoming and California) can all participate in the systemwide portfolio as their requirements are compatible to the extent that they can be modeled under the same mathematical umbrella.

State Requirements Impacting Allocation

Oregon's jurisdictional requirements, as defined primarily by SB 1547 and HB 2021, lead PacifiCorp to measure and reduce carbon emissions allocated to Oregon. This requirement is unique and distinct from merely meeting reliability measurements at the lowest possible cost regardless of technology type. In contrast, Washington requires resources to be selected under the Social Cost of Greenhouse Gases (SCGHG) price policy scenario and measures environmental compliance based on eligible megawatt-hours that are allocated to Washington. While these objectives appear similar, the regulatory requirements for enacting each is distinct and incompatible in terms of mathematical modeling. Because no two jurisdictions' modeling requirements align, even when they appear to have similar broad objectives, PacifiCorp runs separate jurisdictional models for Oregon and Washington for each study, as described earlier in the chapter.

Allocation Protocol

PacifiCorp's jurisdictional modeling approach relies on assumptions regarding the cost-allocation of existing resources and newly selected proxy resources between each jurisdiction. While cost-allocation assumptions for Washington State are determined by the recently approved Washington 2026 Protocol,[15] there is currently no decision or agreement among five of PacifiCorp's states (Oregon, Idaho, California, Wyoming and Utah), and therefore no clear cost-allocation methodology beginning in 2026. In lieu of a clear determination, PacifiCorp assumes allocations prescribed by the previously approved 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol).[16] Taken together, these cost-allocation assumptions result in most existing resources being allocated to each jurisdiction on a system basis, barring resources that are prohibited (e.g. coal in Oregon and Washington), and all proxy resource selections being situs (100 percent) allocated to the jurisdiction for which the resource was optimally selected. To the extent that resources are not retired in the system model run, it is assumed that jurisdictions which can receive the output of these resources would continue to share in their costs and benefits. IRP modeling has historically been agnostic about future cost-allocation determinations, but the requirement to forecast state-specific generation outcomes for compliance and to fairly allocate states' contribution to resource adequacy, cost-allocation assumptions drive the representation of jurisdictional needs.

2025 IRP Update Approach

Given state policy requirements, a single systemwide portfolio cannot be expected to meet all state-specific compliance obligations. To generate an optimal, six-state preferred portfolio, the

[15] Final Order 08 entered December 22, 2025. *WUTC v. PacifiCorp d/b/a Pacific Power & Light Company, Docket No. UE-250224 (Apr. 1, 2025)*

[16] For example, see Oregon PUC docket UM 1050, Order No. 20-024 entered January 23, 2020.

systemwide portfolio must be integrated with selections optimized under each state's requirements, requiring additional studies. These additional studies are created by calculating a portfolio based on the resource selections of the least-cost MN system portfolio, the least-cost MN Oregon jurisdictional portfolio and the least-cost SCGHG Washington jurisdictional portfolio.

When modeled and enacted programmatically and without bias, this manifests in a preferred portfolio that maintains the integrity of jurisdictional directives.

Jurisdictional Shares

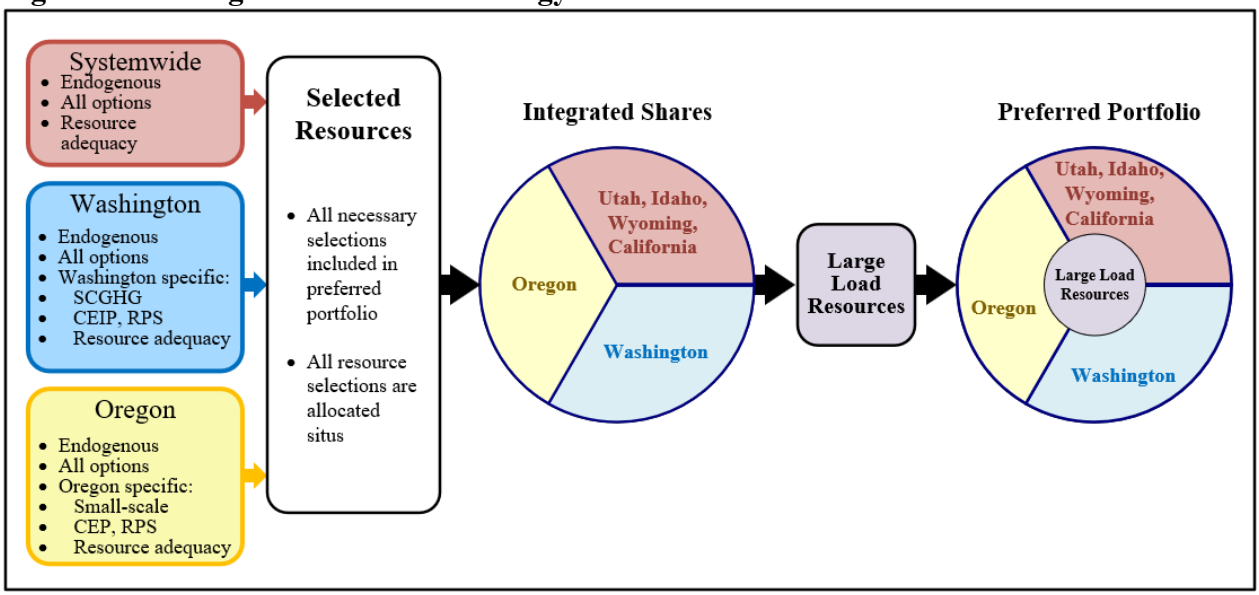
Some jurisdictional resource "shares" – the portion of a proxy resource included in an integrated portfolio that is assumed to be allocated to a given jurisdiction – will result from resource selections that share many characteristics with the selections of other jurisdictions. For example, two or all three of the jurisdictions may identify 500 MW of new wind at a particular location and in a particular year. Other jurisdictional resource shares may be unique selections for only one jurisdiction.

Recognize, however, that focusing on whether or not resource shares are obviously situs or seemingly split from a larger multijurisdictional share has significantly less relevance than it might at first seem. If two jurisdictions select a given resource type in a given location in the same year, this does not mean that the two jurisdictions are sharing a single project. The proxy-driven IRP analysis does not assume the number or size of individual projects, even when only one jurisdiction makes a unique selection which would be self-evidently situs. This is because any amount of proxy resource could represent a single project or multiple projects if a selected resource of a given type in a given location were to materialize in the real world. For example, an identified resource volume of 500 MW could be a single resource, five 100 MW resources, or 500 1 MW resources. These resources may, in reality, turn out to be miles distant from each other within the broad areas defined by the IRP topology. IRP analysis, including in this 2025 IRP Update, is proxy based and must necessarily leave certain determinations to the future and to downstream processes. Proxy resource analysis in an IRP therefore focuses on the amount, type, timing, and location of resources selected for a jurisdiction as a signal to other processes. For IRP purposes, it makes no difference if a particular jurisdiction selects 50 MW of a larger 100 MW resource, or 50 MW of a distinct resource. That determination does not impact the intended market signal of an IRP analysis and will later be resolved based on actual projects when proposed resource sizes, locations and costs become known. For the purposes of IRP reporting, all jurisdictional shares are considered situs in this regard, such that each state can see what the model selected for its benefit.

Preferred Portfolio Integration Strategy

Figure 6.4 illustrates the strategy for the integration of optimal resource selections for all states. The most cost-effective resources from the Oregon and Washington jurisdictional run are selected for those jurisdictions. Similarly, the most cost-effective resources from the systemwide resource adequacy run are selected for the UIWC jurisdiction.

Figure 6.4 – Integrated Portfolio Strategy



Systemwide Portfolio[17]

This portfolio is developed through the iterative process without any restrictions on resource selection or requirements to comply with emissions policies.[18] A system level resource adequacy constraint is implemented as discussed above to ensure adequate capacity selections to achieve resource adequacy requirements. This portfolio serves as a baseline against which to compare any changes to the resource adequacy selections in the final portfolio based on state requirements. As an example, if the systemwide portfolio were to only select new gas resources, Oregon and Washington would need to acquire other resources for resource adequacy as they are not able to participate in new gas and meet emissions targets.
Additionally, the systemwide portfolio determines the selections for the UIWC jurisdiction.

Utah, Idaho, Wyoming and California (UIWC) Portfolio

In this Update, these four states continue to have policies that can be represented together in a single portfolio without policy conflicts, and without conflicting with a systemwide "unconstrained" model run. For this reason, the systemwide portfolio determines the selections for the UIWC jurisdiction.

Oregon and Washington Policy Portfolios

Oregon and Washington state policies require special consideration in modeling. Because Washington requires resource selection and evaluation under SCGHG, PacifiCorp must model the

[17] Dispatch of coal resources is based on economics in all portfolios using the marginal cost of fuel rather than a 0 cost for fuel once the current minimum take contracts expire in 2030. OR LC-85 Order 26-054 item 5.a part 2 "Additionally we direct the company to…allow the preferred portfolio…coal fleet is allowed to dispatch economically…"
[18] See Appendix G, stakeholder feedback form #9 (Sierra Club, et al.)

entire system in both capacity expansion and dispatch under this price policy in distinct runs for Washington. Resource selections made under SCGHG are unlikely to be the most economic selections for the system as a whole or for Oregon, so the Washington jurisdictional portfolio is only used to determine Washington proxy resource selections. Additionally, Washington's compliance with the Clean Energy and Transformation Act (CETA) is based on generation of clean energy. In contrast, Oregon Senate Bill 1547 mandates that Oregon customers no longer participate in coal generation beginning in 2030. Any consideration of Oregon resources must evaluate how Oregon will replace participation in the existing coal capacity. On top of this need, Oregon compliance with House Bill 2021 is based on Oregon-allocated emissions. As a result, Oregon-allocated emitting resources are required to generate below the level generally dictated by economics in order to ensure emissions reductions are met. To achieve these goals, Oregon-allocated gas generation must decrease and Oregon-allocated clean energy must increase relative to unconstrained system operations.

Large Load Resources

Table 6.1 presents aggregated large load data in compliance with the Oregon Public Utility Commission's order in docket LC-85.

Table 6.1– Large Load Resource Status[19]

Status	PACE (MW)	PACW (MW)
Load Service Evaluation	2600	500
Energized 2025 year-end	839	592
Forecasted 2027 year-end	565	772
Contracted load, Max Ramp	839	1054

In the 2025 IRP Update, new contracted large load is not included in jurisdictional portfolios. The new contracted large load is added to the integrated shares in the integrated portfolio LT model run. PLEXOS selects proxy resources to accompany the new contracted large load in this model run. PacifiCorp selected this approach so that resources required for new contracted large load could be identified separately from those resources required to serve existing retail load.

[19] Oregon PUC Order No. 26-054 p.4 – Report on large load

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CHAPTER 7 – PREFERRED PORTFOLIO ANALYSIS

Introduction

This chapter presents the analysis and selection of the 2025 IRP Update preferred portfolio.[1] This analysis includes a comparison of changes relative to the 2025 IRP preferred portfolio, an updated assessment of eligible variant portfolios, and a robustness analysis.

PacifiCorp's long-term resource planning process analyzes eligible resource portfolios and makes a least-cost least-risk determination, leading toward the selection of a single "preferred" portfolio. Eligible portfolios include only those resource plans that are developed under initial conditions aligned with the best available forecast data, regulatory requirements and operational realities. Eligible studies are discussed in detail later in this chapter as part of the pathway to selecting a preferred portfolio. Additional non-eligible portfolios are presented as "sensitivities" in the next chapter.

The selection of the updated preferred portfolio is driven by all modeled inputs and assumptions, some of which have changed since the 2025 Integrated Resource Plan (IRP), filed on March 31, 2025. For example, the updated preferred portfolio is consistent with PacifiCorp's most recent load-and-resource balance.[2]

Note on Sensitivities

New to the 2025 IRP Update, sensitivity studies have now been given their own chapter (Chapter 8) to emphasize the relevance and analysis of these portfolios.

Distinct from portfolios that are eligible for selection as the preferred portfolio, the 2025 IRP Update included several sensitivities. As in past IRPs, sensitivities are designed to be informative as they cannot realistically be executed by the company. Also, while sensitivities are not expected to impact preferred portfolio selection directly, influence is possible to the extent that a sensitivity indicates additional analysis that might serve to improve the preferred portfolio as selected from among the eligible variants. In most cases, however, it is expected that even where a sensitivity performs better on some metrics than the preferred portfolio, this only occurs because sensitivities are allowed to escape the bounds of expected base forecasts, regulatory requirements or PacifiCorp's capabilities.

Preferred Portfolio Analysis Path Overview

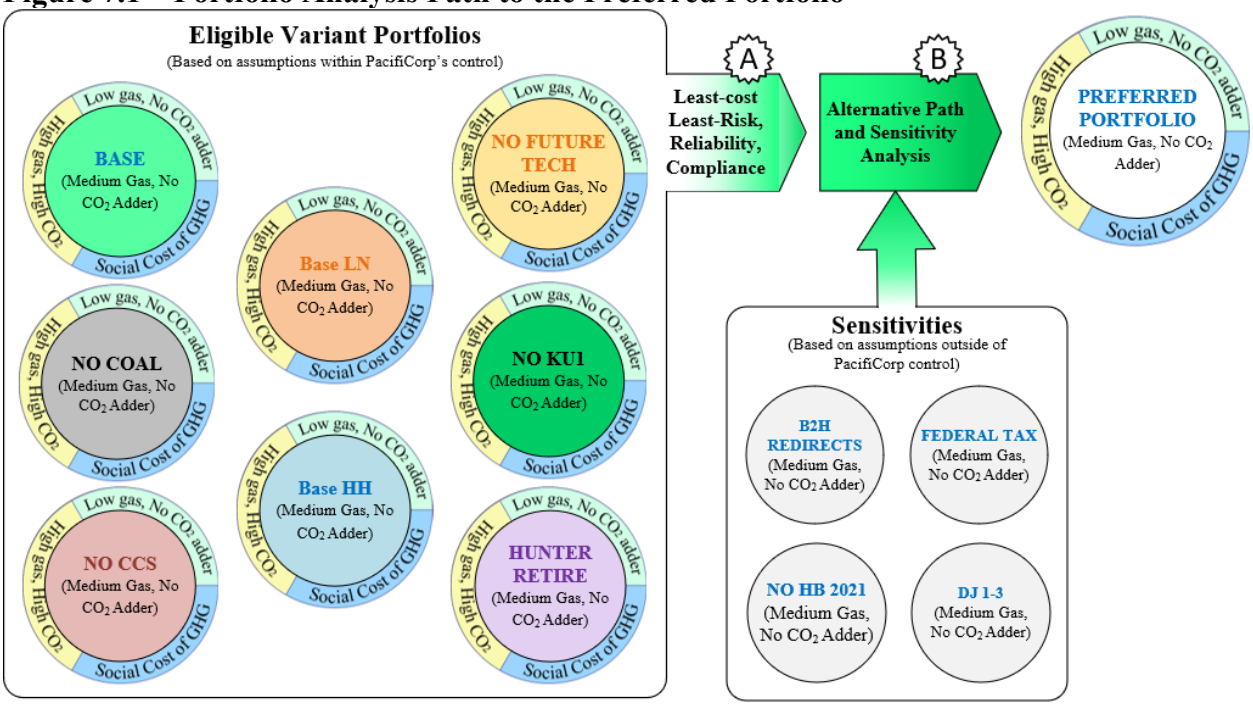
Throughout the 2025 IRP Update development process, PacifiCorp has actively engaged with stakeholders and regulators through comments regarding the 2025 IRP and through regular

[1] See the introduction to Chapter 6 for definitions of "portfolio" and the "preferred portfolio". Also see Appendix Z.
[2] See Chapter 4 – Load and Resource Balance

meetings in the 2027 IRP public input meeting series. While portfolios change and the process evolves, a major planning theme that remains strong is that of high volatility. As described in this update and particularly in Chapters 3 and 6, this volatility stems largely from changes in the federal policy landscape, stakeholder and regulatory feedback, and economic drivers behind fluctuating market prices and resource costs. Figure 7.1 illustrates the relationship among eligible variant portfolios and the selection of the preferred portfolio.

The least-cost least-risk portfolio is determined in step "A", noted in the figure that follows. However, this is not the last analytical step to select the content of the preferred portfolio. In step "B", there is a consideration of variant and sensitivity portfolio outcomes, and alternative path analysis, used to inform further exploration. A sensitivity may reveal an interesting trade-off between reliability and emissions, for example. An incremental change to the preferred portfolio might be studied to determine the cost and risk of reducing reliability or increasing emissions to achieve a portfolio that is better balanced to meet all requirements. While such final adjustments are not common, they have occurred in prior IRPs and are a part of the analytical process.

Figure 7.1 – Portfolio Analysis Path to the Preferred Portfolio[3]



Preferred Portfolio Selection Summary

[3] The price-policy scenario indicated in the center of each circle represents the conditions under which the portfolios were compared to select a preferred portfolio. For example, the LN and HH portfolios were optimize under LN and HH conditions, respectively, but are dispatched under expected future conditions when selecting the preferred portfolio.

The following section justifies the selection of the preferred portfolio and shows detailed results, including jurisdictional shares and transmission upgrades.

Preferred Portfolio Selection

PacifiCorp developed eight integrated portfolios in the 2025 IRP Update that were eligible for selection as the preferred portfolio. Each eligible portfolio is run under the "MN" (medium natural gas price, no CO_2 dispatch adder) price-policy conditions to observe how the portfolio performs under expected future conditions. These portfolios are the Base MN, optimized using base assumptions, plus seven eligible variant studies: Hunter Retire, All Coal Retire, No Kemmerer Unit 1, No CCS, No Future Tech, LN and HH. These studies are described and analyzed in the "Eligible Variant Portfolios" section below, with a shorthand definition of each given in Table 7.11.

Table 7.1 below summarizes the cost results on a present value revenue requirement (PVRR) basis ($ millions) of the eligible studies *when dispatched under the MN (medium gas price/ no CO_2 cost adder) price-policy scenario*.[4] Under MN conditions, the Base MN portfolio reports the lowest total system cost on both a risk adjusted and with end effects basis is selected as the preferred portfolio.

Table 7.1 – Base and Eligible Variant Case PVRR and Ranking for Selection

MN Price Policy - Dispatch	ST Value			Risk Adjusted			With End Effects			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Stochastic PVRR	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Portfolio	Rank	Total CO2 Emissions, 2025-2045 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
Base MN	37,463	$64	2	37,922	$0	1	46,940	$0	1	416,003	77,856.12	4
MN Hunter Retire	38,367	$968	5	39,208	$1,287	5	48,644	$1,704	5	390,749	52,602.05	3
MN All Coal Retire	41,599	$4,199	8	42,329	$4,407	8	51,670	$4,730	8	338,147	-	1
MN No Future Tech	38,954	$1,554	7	39,783	$1,862	7	49,223	$2,282	7	453,006	114,858.97	7
MN No KU 1	38,917	$1,518	6	39,560	$1,638	6	48,965	$2,024	6	443,105	104,958.39	6
MN No CCS	38,175	$775	4	38,727	$805	4	47,412	$471	3	469,366	131,218.92	8
HH	37,913	$514	3	38,549	$627	3	47,791	$850	4	385,256	47,109.46	2
LN	37,399	$0	1	38,032	$110	2	47,201	$260	2	431,370	93,223.32	5

Robustness Analysis

The most comprehensive metric for selecting the preferred portfolio is the total PVRR, shown in the eighth column of Table 7.1, above. This total PVRR includes both stochastic risk and end effects, and is used to determine the least-cost, least-risk portfolio in consideration of all modeled requirements. Under this comprehensive metric, the selected preferred portfolio, "Base MN", has the top rank, whereas the next closest portfolio, "LN", is $260 million more costly as seen in

[4] The LN and HH portfolios were originally optimized under the low-gas/ no CO_2 and high-gas/ high CO_2 price-policy scenarios respectively. Other than the price environment used to develop each of these two portfolios, all base assumptions were used. This results in portfolios that are theoretically achievable by PacifiCorp and are therefore eligible to be selected for the preferred portfolio. For the purposes of cost and risk comparison in Table 7.1, the LN and HH portfolios were run under expected case conditions to evaluate how they compare to the other eligible variants.

column 9 of Table 7.1. In addition to the total PVRR metric, each eligible variant portfolio may perform better or worse in each core metric given in Table 7.1 (risk-adjustment, end effects and emissions) relative to its PVRR cost.

This robustness analysis emphasizes cost-to-risk balance by placing all eligible studies on a scatter plot for each metric. In these views, portfolios with lower costs and risks will gravitate toward the bottom left corner of each plot, representing lower PVRR and a lower risk metric result. The placement of each eligible variant and metric is discussed below.

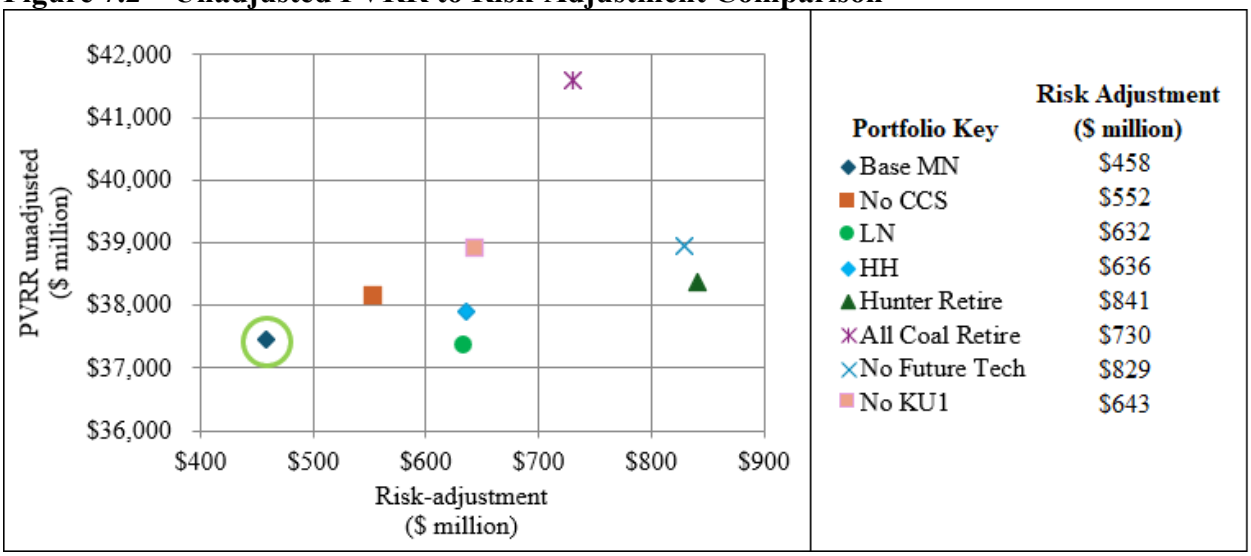
While the selection of the "expected case" as the preferred portfolio is probable in any set of eligible studies, there are factors that can potentially shift this choice, such as modeling limitations, interactions between analytical evaluation steps, and errors. An unintuitive outcome can point to the need for corrections or for additional studies. In the 2025 IRP Update, the outcomes for each metric support the reasonable selection of the Base MN expected case, as illustrated in Figure 7.2 through 7.6. The Base MN case is circled in green for emphasis in each figure's graph.

Risk-Adjustment

Figure 7.2 depicts a scatter plot of the stochastic risk adjustment across the x-axis and the unadjusted "ST value" PVRR as presented in the second column of Table 7.1, above. This figure illustrates that compared to all other eligible variant portfolios, the Base MN preferred portfolio is substantially less averse to volatility, represented in the stochastic analysis as upper tail risk. This means that while other portfolios struggle with future volatility, the Base MN remains relatively viable. Of the eligible variants, the No Future Tech, All Coal Retire, and Hunter Retire report risk adjustment costs approaching double that of the Base MN preferred portfolio. The second lowest-risk portfolio for this metric is the No CCS counterfactual study, which still carries a 21% higher stochastic risk-adjustment cost compared to the Base MN.

While the LN portfolio is shown to be competitive throughout the robustness analysis, the heavy lean into increased stochastic risk shown in Figure 7.2 weighs against its selection as the preferred portfolio.

Figure 7.2 – Unadjusted PVRR to Risk-Adjustment Comparison

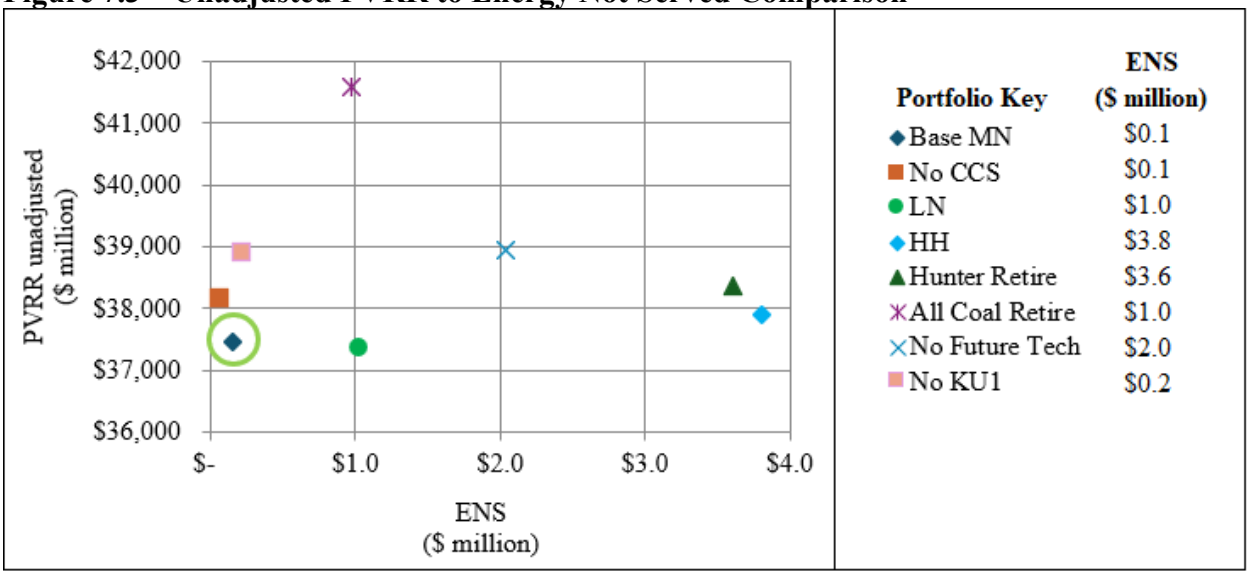


Energy Not Served (ENS)

The cost of ENS is low among all cases but remains indicative of relative loss of load risk. Cost impacts of ENS are low primarily because all portfolios are required to be reliable, limiting the bounds of the relative cost differentials.

The Base MN portfolio reports only slightly more ENS than the No CSS portfolio, but at a lower cost, landing the Base MN closest to the lower-left of the scatter plot. As with the stochastic risk-adjustment, this metric also supports the selection of the Base MN as the preferred portfolio. The least well-performing portfolios are the Hunter Retire and HH portfolios, which are hampered in reliability by the loss of significant dispatchable resources. The All Coal Retire portfolio manages to achieve relatively low ENS, but at a dramatically higher unadjusted PVRR cost and total PVRR cost. Figure 7.3 illustrates the relative cost-effective robustness of the Base MN portfolio.

Figure 7.3 – Unadjusted PVRR to Energy Not Served Comparison



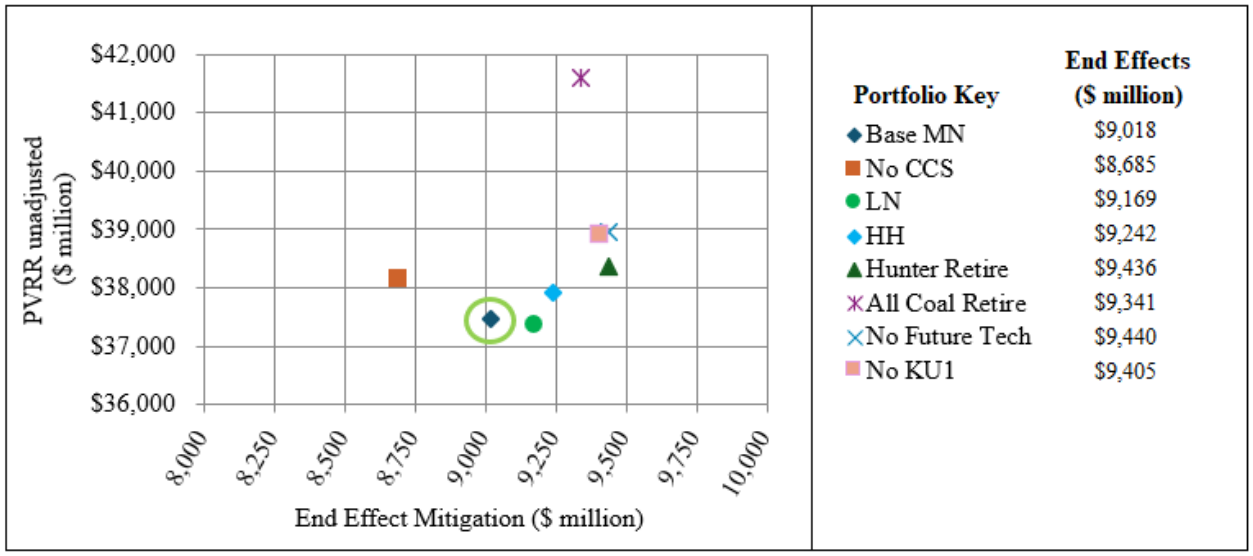
End Effects Mitigation

Figure 7.4 reports the cost of end effects mitigation relative to the unadjusted PVRR of each portfolio. Prior to end effects mitigation, the Base MN is already ranked least-cost, least risk after the application of the stochastic risk-adjustment. As an indicator of robustness among other possible portfolios, the Base MN has the second-lowest end effects mitigation cost and remains the top-ranked portfolio.

While the absolute value of end effects appears very high, ranging from $8.6 to $9.4 billion, the impact on the total PVRR is completely relative. In relative terms, PVRR impacts range from $0 in the No CSS portfolio to $755 million in the No Future Technology case. This differential carries a larger impact than the relative stochastic risk-adjustment but is also substantially less than the unadjusted PVRR differential which goes as high as $4 billion in the All Coal Retire portfolio.

Accordingly, the scatter plot shows that the end effects mitigation costs cluster within a relatively narrow range on the X-axis. This outcome reasonably supports the selection Base MN as the preferred portfolio.

Figure 7.4 – Unadjusted PVRR to End Effects Mitigation Comparison



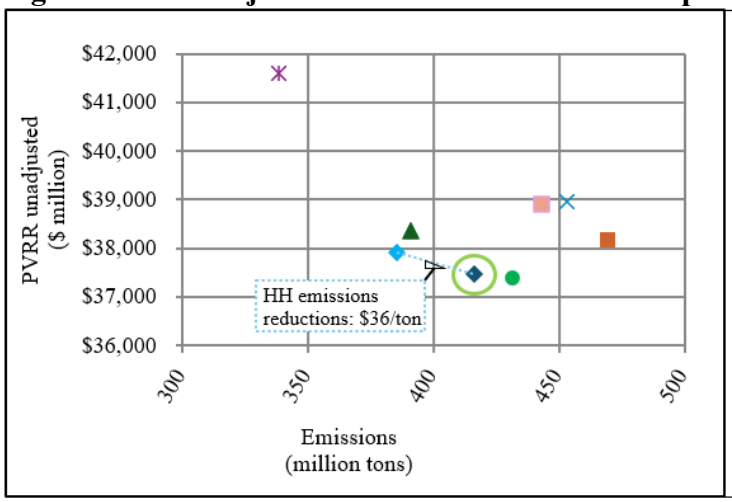
Emissions

Figure 7.5 maps the scatter plot of emissions in millions of tons (x-axis) to unadjusted PVRR (y-axis). The data to the right of the graph includes both the emission in millions of tons and the emission reduction cost[5] relative to the Base MN portfolio, in dollars-per-ton, for each study that has lower emissions than the Base MN portfolio. The Base MN preferred portfolio falls roughly to the middle of the pack in terms of total emissions, while yielding the second-to-least-cost unadjusted PVRR. The placement of the Base MN in the middle of the pack is intuitive, as reducing emissions is mandated by various policies but also carries a cost.

The three lowest-emission producing portfolios are also the three studies with the strongest and most transparent emissions-reducing drivers. In the extreme case, All Coal Retire, emissions are the lowest of any portfolio, but at a significantly higher cost that exceeds the Base MN unadjusted PVRR by $4.1 billion. At the same time, the All Coal Retire portfolio succeeds in reducing emissions by less than an additional 20% relative to the Base MN portfolio. Under the MN price-policy scenario, the HH-optimized portfolio results in a roughly 7.5% reduction in total emissions over the study horizon. That emissions reduction comes at cost equivalent to approximately $36/ton, as a result of the additional non-emitting resources and other changes that were part of the HH portfolio. The Hunter Retire portfolio achieves fewer emission reduction than the HH portfolio, and at a higher cost of $77/ton, while the All Coal Retire portfolio achieves a 19% reduction in emissions but at the highest incremental cost, at $125/ton.

In sum, the Base MN preferred portfolio achieves compliance with emissions requirements while exhibiting a reasonable balance against cost.

Figure 7.5 – Unadjusted PVRR to Emissions Comparison



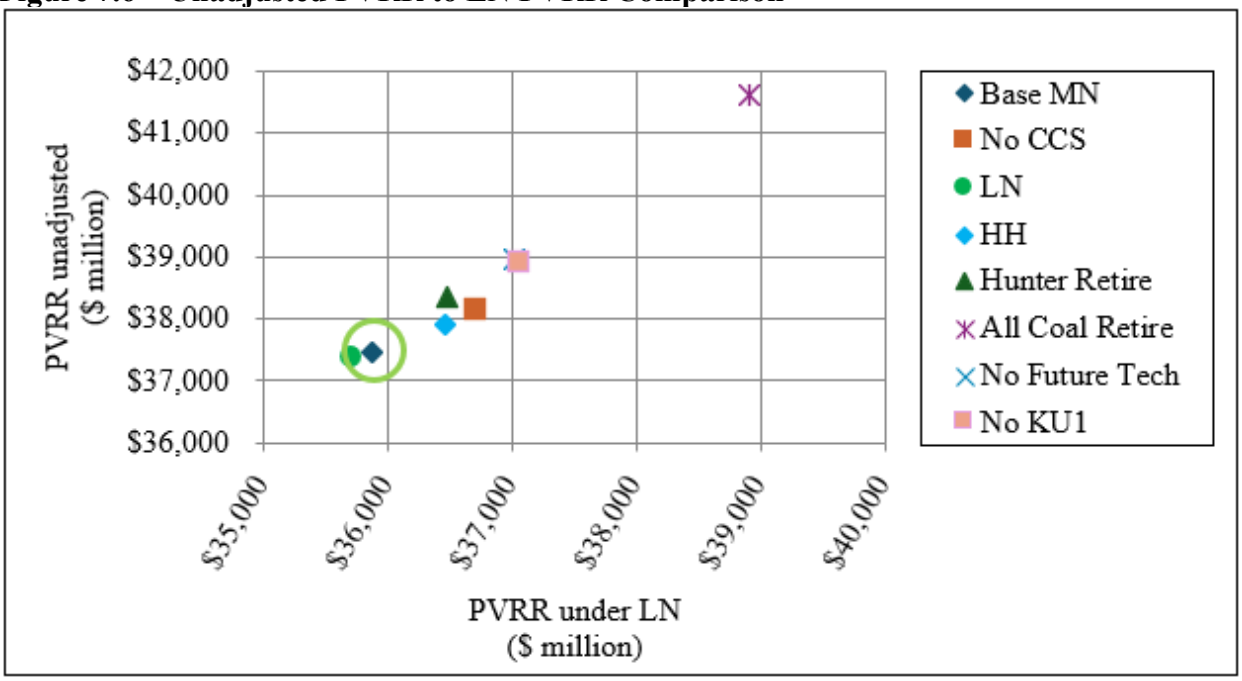
Portfolio Key	Emissions (million tons)	Emission Reduction Cost ($ per ton)
Base MN	416	Base
No CCS	469	n/a
LN	431	n/a
HH	385	$36
Hunter Retire	391	$77
All Coal Retire	338	$125
No Future Tech	453	n/a
No KU1	443	n/a

[5] Calculated as the change in unadjusted PVRR divided by the change in present value emissions, relative to the Base MN portfolio.

Low-gas, No CO_2 Policy Adder

A more robust portfolio will perform well under price-policy futures other than the expected case. This scatter plot maps each portfolio's unadjusted PVRR when dispatched under LN conditions (x-axes) to the unadjusted PVRR when dispatched under MN conditions. The LN portfolio is generally expected to perform best under LN conditions because the portfolio was optimized specifically for the LN conditions, and this can be seen in its position in Figure 7.6, slightly to the left of the Base MN. The placement of the Base MN portfolio deep in the lower left compared to other portfolio is indicative of its relatively low cost and excellent performance under LN conditions. This outcome strongly supports the robustness and selection of the Base MN as the preferred portfolio.

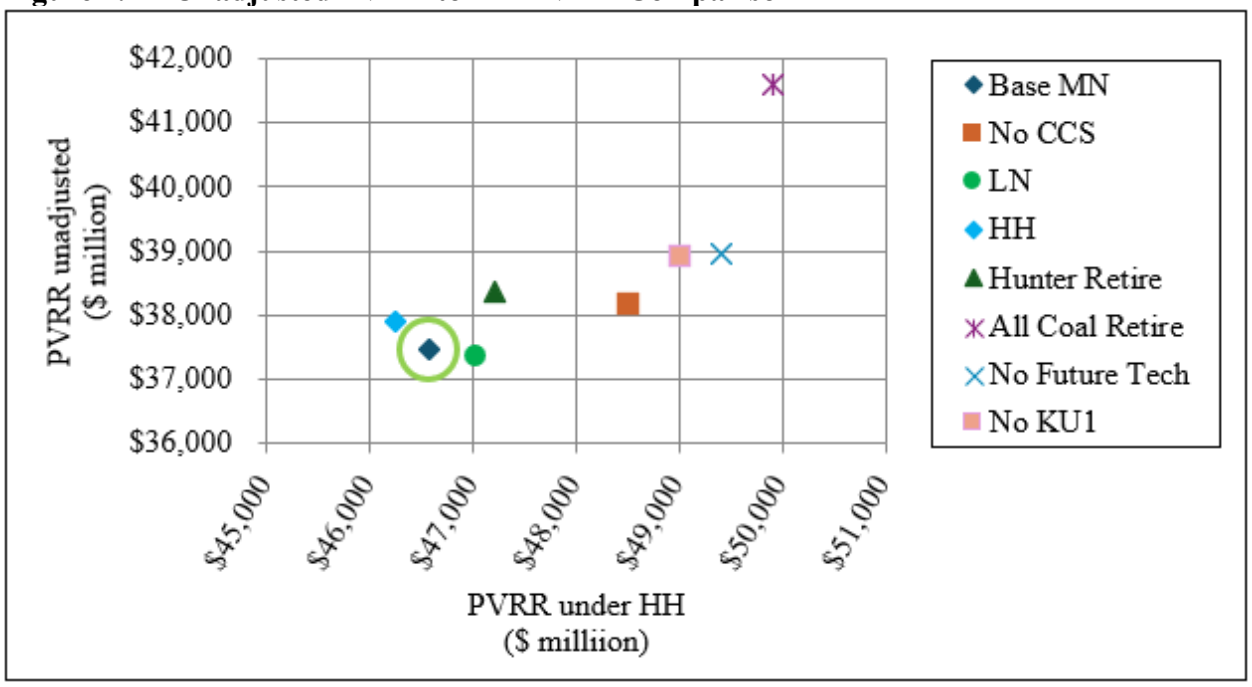
Figure 7.6 – Unadjusted PVRR to LN PVRR Comparison



High-gas, High CO_2 Policy Adder[6]

Similar to the LN scatter plot just discussed, the Base MN portfolio performs excellently under the HH price-policy future, reporting only a slightly higher cost under high-gas price, high-CO_2 cost conditions. Notably, the HH portfolio also performs relatively well under expected case conditions. This is most likely because Base MN policy requirements outside of the gas price and the CO_2 dispatch adder are understandably pushing some elements of resource selection in a similar direction.

Figure 7.7 – Unadjusted PVRR to HH PVRR Comparison



Conclusion to Robustness Analysis

The selection of the Base MN portfolio as the preferred portfolio is strongly indicated across the various metrics, including total PVRR. As in the 2025 IRP, total PVRR continues to be the most relevant indicator. The excellent performance of the Base MN across most metrics, and notably its performance in the LN and HH price-policy futures, lends confidence to this decision.

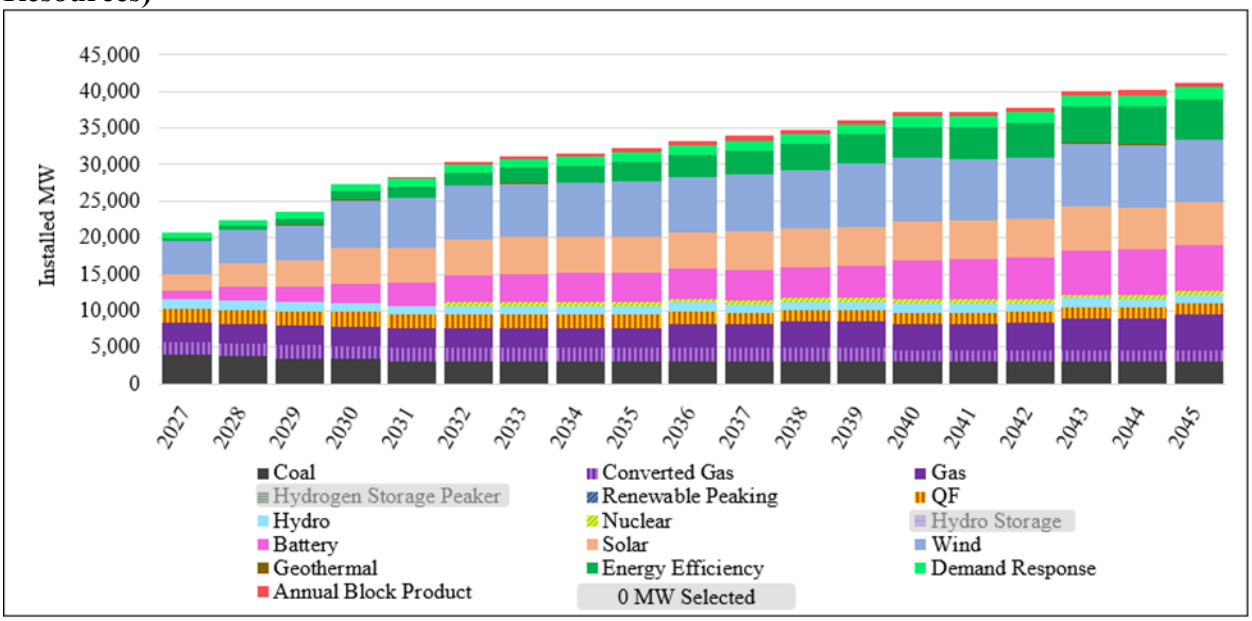
Preferred Portfolio Results

Figure 7.8 illustrates the resources (existing and new) comprising the 2025 IRP Update preferred portfolio. The updated preferred portfolio includes over 2,200 MW of new gas and gas peaking resources. New gas resources are competitive with new wind and solar resources without IRA/IIJA

[6] See Appendix G, stakeholder feedback form #19 (Sierra Club, et al.)

productions tax credits. Driven largely by Oregon and Washington state policies, the draft preferred portfolio continues to indicate significant renewable resource additions, with over 6,000 MW of new wind, solar, and small-scale solar resource additions by the end of 2045.

Figure 7.8 – 2025 IRP Update Integrated Portfolio Selections (Existing and Planned Resources)[1]



[1]In addition to the illustration of resources by technology type, the 2025 IRP Update preferred portfolio also includes an average of 516 MW annual block purchases from 2031-2045. Additional details on the blocked purchase resource options may be found in Chapter 5.

Storage remains a large portion of the new resources identified in the 2025 IRP Update preferred portfolio, with over 1,000 MW of new 4-hour lithium-ion battery storage selected by 2030 and over 4,000 MW by 2045. Finally, the preferred portfolio includes an average of 516 MW of annual block market purchases from 2031-2045. Details regarding the type, timing, and quantity of new resources selected in the 2025 IRP Update preferred portfolio, along with existing resource changes, are included in Table 7.2.

Table 7.2 – 2025 IRP Update Preferred Portfolio (Installed Capacity, MW)

Summary Portfolio Capacity by Resource Type and Year, Installed MW																			
Resource	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																				
Gas - CCCT	-	-	-	-	-	-	-	-	19	525	-	364	-	-	-	-	263	-	199	1,370
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	50	394	-	403	853
Nuclear	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	20
DSM - Energy Efficiency	213	224	235	269	346	329	276	308	306	315	278	305	284	265	272	293	264	207	164	5,153
DSM - Demand Response	2	28	182	112	22	42	32	34	33	27	5	71	34	33	51	32	25	51	215	1,031
Renewable - Wind	-	-	366	1,697	-	-	-	11	124	93	268	148	755	-	-	-	243	-	-	3,705
Renewable - Small Scale Wind	-	-	13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13
Renewable - Utility Solar	-	255	125	1,058	-	-	-	-	-	6	259	-	-	-	-	-	774	-	-	2,477
Renewable - Small Scale Solar	-	-	13	184	-	-	-	18	26	27	29	32	25	-	-	-	-	-	-	354
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (< 8 hour)	-	715	102	548	228	154	152	57	17	55	86	9	244	1,033	129	200	298	127	-	4,154
Renewable - Battery (8-23 hour)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (24+ hour)	-	-	-	4	54	227	46	-	19	-	-	-	3	-	-	-	11	16	143	523
Other Renewable	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Surplus Battery	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Block Product	-	-	-	-	212	208	345	457	640	640	640	640	640	640	640	640	640	640	640	516
Large Load Resources	-	775	273	142	483	816	168	2	2	2	2	593	206	106	389	642	129	2	2	4,734
Existing Unit Changes																				
Coal Plant Retirements - Minority Owned	-	(33)	(123)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(304)
Coal Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Ceases as Coal	-	(220)	(205)	-	(700)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,125)
Coal - CCS	-	-	-	-	415	-	-	-	-	-	-	-	-	-	-	-	-	-	-	415
Coal - Gas Conversions	-	-	205	-	-	-	-	-	-	-	-	-	-	(255)	-	-	-	(106)	-	(156)
Gas Plant Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Non-Thermal	-	-	-	-	-	-	-	(3)	-	-	-	(34)	-	-	-	-	-	-	-	(37)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	(333)	-	-	-	-	(632)
Expire - Solar PPA	-	(2)	-	-	(9)	-	-	-	-	-	(100)	-	-	-	(65)	-	-	(210)	-	(387)
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	0	(1)
Expire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**215**	**1,742**	**1,186**	**3,767**	**851**	**2,276**	**1,019**	**884**	**1,186**	**1,690**	**1,467**	**2,134**	**2,211**	**1,822**	**1,083**	**1,857**	**3,041**	**726**	**1,746**	

Jurisdictional Shares

Figure 7.9 through 7.11 report the cumulative firm capacity additions for proxy resources assigned to each jurisdiction by year and resource type, in megawatts, along with the annual firm capacity need for each jurisdiction. The annual firm capacity need for each jurisdiction is determined by calculating the difference between the existing resources allocated to a jurisdiction and that jurisdiction's resource adequacy need based on its load in each year.

Table 7.3 through 7.5 report the incremental nameplate capacity additions for proxy resources assigned to each jurisdiction by year and resource type, in megawatts.

Figure 7.9 - Utah/Idaho/Wyoming/California Resource Adequacy Need (megawatts)

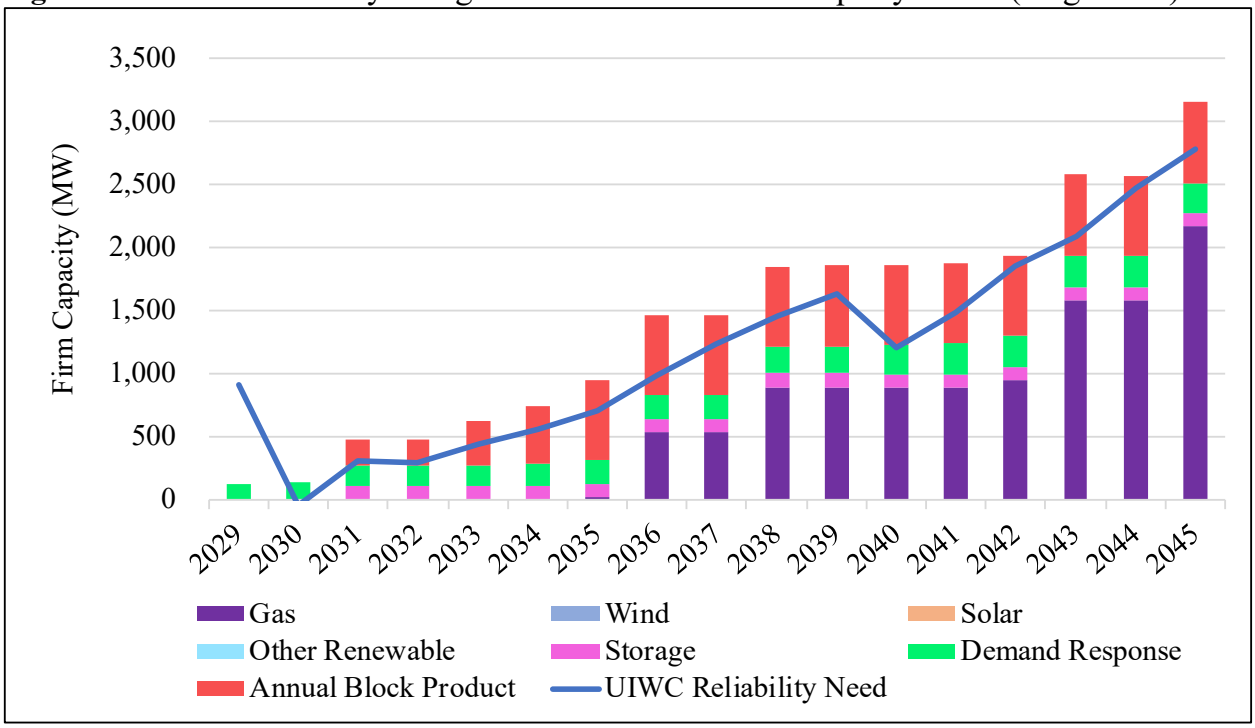


Table 7.3 – Utah/Idaho/Wyoming/California Nameplate Capacity Additions (megawatts)

UIWC Shares by Resource Type and Year, Installed MW																				
	Installed Capacity, MW																			
Resource	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Gas - CCCT	-	-	-	-	-	-	-	-	19	525	-	364	-	-	-	-	263	-	199	1,370
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	50	394	-	403	853
Block Product	-	-	-	-	212	208	345	457	640	640	640	640	640	640	640	640	640	640	640	516
Nuclear	-	-	-	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	99	113	119	139	213	201	144	181	178	186	150	184	167	152	149	176	158	108	112	2,927
DSM - Demand Response	2	4	161	38	16	18	16	23	19	22	1	59	27	29	33	28	21	1	212	728
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (< 8 hour)	-	-	-	-	151	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151
Renewable - Battery (24+ hour)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 7.10 - Oregon Resource Adequacy Need (megawatts)

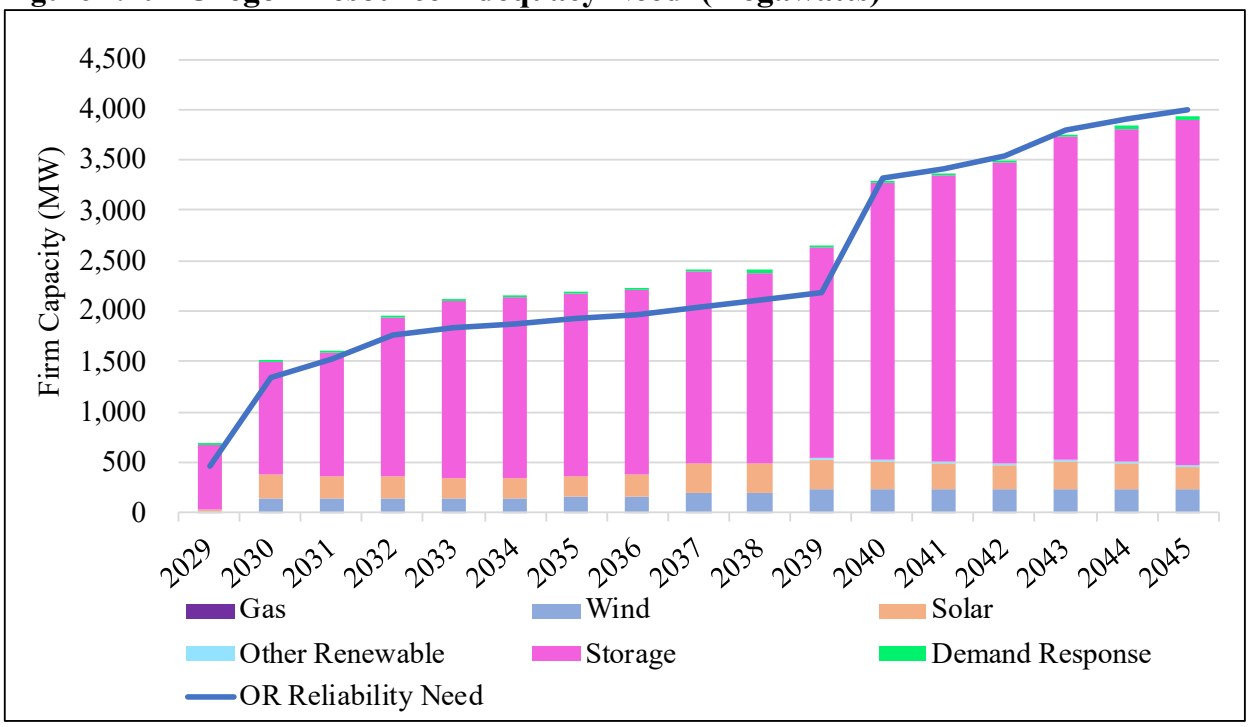


Table 7.4 – Oregon Nameplate Capacity Additions (megawatts)[7]

OR Shares by Resource Type and Year, Installed MW																				
	Installed Capacity, MW																			
Resource	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Block Product																				
Nuclear	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	20
DSM - Energy Efficiency	97	95	100	112	112	108	111	106	108	110	109	105	102	100	111	106	98	91	47	1,930
DSM - Demand Response	-	16	4	74	5	25	9	12	13	5	4	12	6	4	4	4	3	49	3	250
Renewable - Wind	-	-	137	1,183	-	-	-	11	124	93	265	148	755	-	-	-	243	-	-	2,960
Renewable - Utility Solar	-	34	0	986	-	-	-	-	-	3	259	-	-	-	-	-	774	-	-	2,057
Renewable - Small Scale Solar	-	-	13	184	-	-	-	18	26	27	29	32	25	-	-	-	-	-	-	354
Renewable - Battery (< 8 hour)	-	615	102	548	77	154	152	57	17	55	86	9	244	820	129	200	298	127	-	3,691
Renewable - Battery (24+ hour)	-	-	-	4	54	227	46	-	19	-	-	-	3	-	-	-	11	16	143	523

[7] Procurement targets and timeline for Oregon in response to LC-85 Order # 26-054 item 3.a.ii "provide a structured execution strategy with time-bound deliverables regarding procurement…"

Figure 7.11 - Washington Resource Adequacy Need (megawatts)

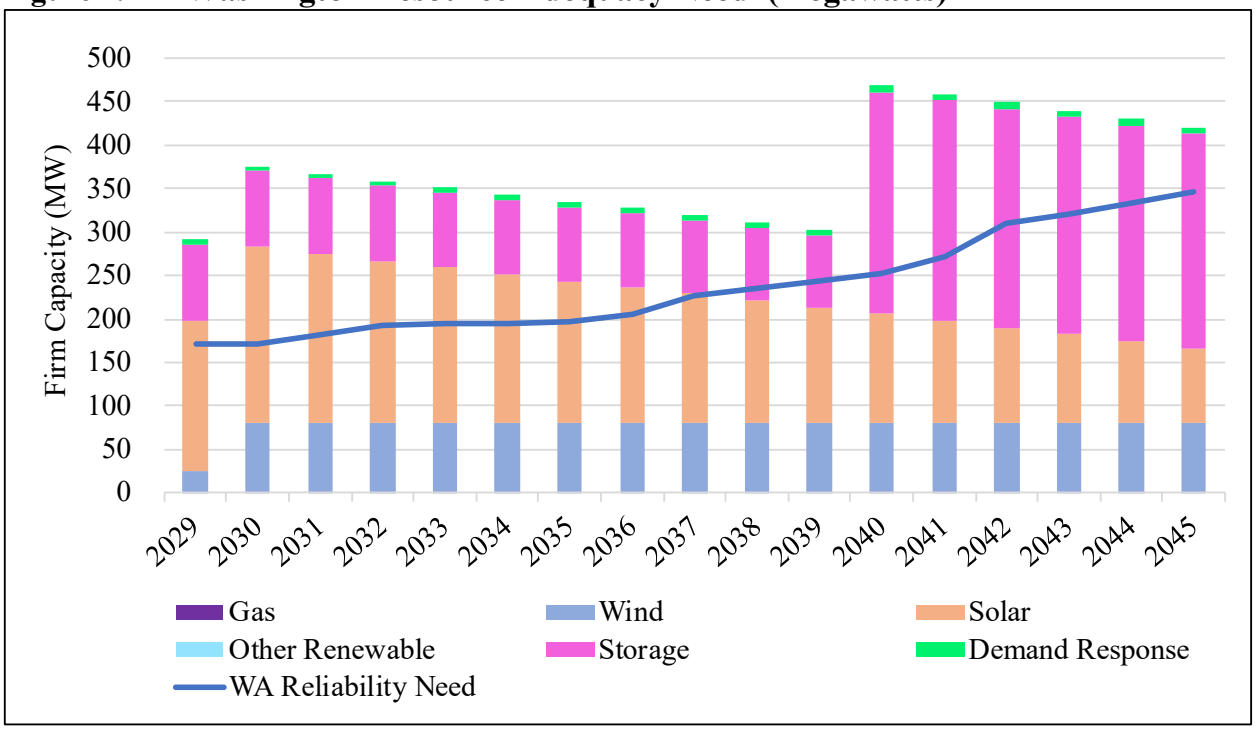


Table 7.5 - Washington Resource Nameplate Capacity Additions (megawatts)

WA Shares by Resource Type and Year, Installed MW																				
	Installed Capacity, MW																			
Resource	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	32
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	16	15	16	18	21	21	21	21	20	19	20	16	15	13	11	12	8	7	5	296
DSM - Demand Response	0	8	17	1	2	-	7	-	1	0	0	1	1	1	14	0	0	1	0	55
Renewable - Wind	-	-	228	514	-	-	-	-	-	0	3	-	-	-	-	-	-	-	-	745
Renewable - Utility Solar	-	220	125	72	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	419
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (< 8 hour)	-	100	-	-	-	-	-	-	-	-	-	-	-	213	-	-	-	-	-	313
Renewable - Battery (24+ hour)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Figure 7.12 reports the annual nameplate capacity in the 2025 IRP Update relative to the 2025 IRP preferred portfolio over the planning horizon through 2045.

Figure 7.12 – Incremental Changes in 2025 IRP Update less 2025 IRP Preferred Portfolio

Transmission Upgrades

In the 2025 IRP Update, many transmission upgrades and the accompanying resources reflect the results of PacifiCorp's generator interconnection "cluster study" process for evaluating proposed resource additions. Transmission expansion projects can include development of new segments and exploration of new routes that have connections to other areas. Table 7.6 summarizes the new transmission paths selected to facilitate new generation resources identified as part of the 2025 IRP Update preferred portfolio.

In addition to providing increased interconnection capacity, transmission upgrades are also expected to allow for increased transfer capability between different areas of PacifiCorp's system. The 2025 IRP Update preferred portfolio includes the following transmission upgrades.

Table 7.6 – 2025 IRP Update Interconnection Selections

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2028	B2H	818	300	0	-	100%	Hemingway	Boardman
	B2H - Idaho Power Asset Transfer	600	300	0	-	100%	Borah	Hemingway
	B2H - IPC PTP Eastbound	200	200	0	-	100%	Walla Walla	Borah
	B2H-Enabled BPA Central OR Load Service	0	340	0	-	100%	n/a	n/a
	Serial queue: Central Oregon	0	0	152	4	100%	n/a	n/a
	Utah South - Wasatch Front: Spanish Fork - Mercer 345 kV	300	300	300	138	100%	Utah South	Wasatch Front
2029	Ben Lomond Upgrades	433	433	433	61	100%	NUT	Wasatch Front
	Cluster 1 Area 11: Willamette Valley	0	0	199	14	100%	n/a	n/a
	Serial/Cluster 1/2: Yakima	0	0	123	13	20%	n/a	n/a
2030	Cluster 1 Area 14: Summer Lake	400	400	400	115	100%	Summer Lake	Hemingway
	Cluster 2 Area 23: Willamette Valley	0	0	393	2	100%	n/a	n/a
	Serial/Cluster 1/2: Yakima	0	0	69	7	11%	n/a	n/a
2035	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	78	59	15%	n/a	n/a
2036	Utah South - Wasatch Front: Huntington - Clover 345 kV	800	800	800	277	100%	Utah South	Wasatch Front
2037	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	117	92	23%	n/a	n/a
	Goshen - Blackfoot 161 kV	75	75	42	16	100%	Goshen	Wasatch Front
2039	Cluster 1/2/3: Walla Walla	0	0	71	75	18%	n/a	n/a
	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	450	450	450	481	100%	Willamette Valley	Central OR
2043	Serial through Cluster 1 Area 13: Southern Oregon	0	0	54	13	23%	n/a	n/a
2045	Cluster 2 Area 6: Goshen	150	150	359	145	100%	Goshen	NUT
Grand Total		**4,226**	**3,748**	**4,041**	**1,510**			

Preferred Portfolio Resources

Resource selections in the updated preferred portfolio differ from those in the 2025 IRP preferred portfolio as a consequence of changes to model inputs and assumptions, as detailed in Chapter 6. Table 7.7 presents the breakout of resources by technology type, comparing the update to the full IRP.

Table 7.7 – Resource Technology Type Comparison of the 2025 IRP Update to the 2025 IRP (megawatts)

Summary Portfolio Capacity by Resource Type and Year, Installed MW																			
	Installed Capacity, MW																		
Resource	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																				
Gas - CCCT																				
25 IRP Update	-	-	-	-	-	-	-	-	19	525	-	364	-	-	-	-	263	-	199	1,370
25 IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking																				
25 IRP Update	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	50	394	-	403	853
25 IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear																				
25 IRP Update	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
25 IRP	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	500
Renewable Peaking																				
25 IRP Update	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	20
25 IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	4	-	18	41
DSM - Energy Efficiency																				
25 IRP Update	213	224	235	269	346	329	276	308	306	315	278	305	284	265	272	293	264	207	164	5,153
25 IRP	209	220	239	261	329	291	299	295	299	315	347	314	293	300	303	315	238	205	182	5,254
DSM - Demand Response																				
25 IRP Update	2	28	182	112	22	42	32	34	33	27	5	71	34	33	51	32	25	51	215	1,031
25 IRP	-	63	21	120	99	5	1	3	3	21	112	18	5	24	61	106	29	26	52	769
Renewable - Wind																				
25 IRP Update	-	-	366	1,697	-	-	-	11	124	93	268	148	755	-	-	-	243	-	-	3,705
25 IRP	-	21	794	1,452	344	1	-	29	347	40	175	37	-	376	50	-	20	-	96	3,782
Renewable - Utility Solar																				
25 IRP Update	-	255	125	1,058	-	-	-	-	-	6	259	-	-	-	-	-	774	-	-	2,477
25 IRP	-	222	180	1,690	849	240	403	225	13	-	1	-	554	104	12	-	-	197	75	4,765
Renewable - Small Scale Solar																				
25 IRP Update	-	-	13	184	-	-	-	18	26	27	29	32	25	-	-	-	-	-	-	354
25 IRP	-	-	-	320	2	18	26	21	30	132	-	309	-	-	110	-	-	143	36	1,147
Renewable - Geothermal																				
25 IRP Update	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25 IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (< 8 hour)																				
25 IRP Update	-	715	102	548	228	154	152	57	17	55	86	9	244	1,033	129	200	298	127	-	4,154
25 IRP	-	1,146	242	296	-	119	39	210	20	47	-	175	67	113	67	713	5	459	733	4,451
Renewable - Battery (24+ hour)																				
25 IRP Update	-	-	-	4	54	227	46	-	19	-	-	-	3	-	-	-	11	16	143	523
25 IRP	-	-	-	511	91	3	4	3	4	4	11	83	37	939	107	319	402	197	358	3,073
Annual Block Product																				
25 IRP Update	-	-	-	-	212	208	345	457	640	640	640	640	640	640	640	640	640	640	640	516
25 IRP	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Proxy Resource Technologies

The 2025 IRP Update preferred portfolio is diverse, recommending a range of renewable, storage, nuclear and natural gas resources.

New Solar Resources

The updated preferred portfolio includes 1,635 megawatts of solar by the end of 2030 (of which 197 MW are small scale), and 1,057 megawatts of new solar is online by 2039. An additional 774 MW of utility scale solar is selected by the end of the horizon for a total solar selection of 2,831 MW over the 20-year horizon.

New Wind Resources

The updated preferred portfolio includes 2,076 megawatts of new wind resources by the end of 2030, 3,475 megawatts by 2039 and 3,718 megawatts of new wind resources by the end of the planning horizon.

New Storage Resources

The updated preferred portfolio includes 1,369 megawatts of new storage capacity by the end of 2030, 2,720 megawatts by the end of 2039 and 4,667 megawatts over the 20-year planning horizon.

New Natural Gas Resources

The updated preferred portfolio includes 914 MW of new gas resources by the end of 2039, and 2,223 MW of new gas resources by the end of the horizon. This includes 1,370 MW of new combined cycle resources and 853 MW of new gas peaking resources.

New Renewable Peaking Resources

The 2025 update preferred portfolio indicates a need for flexible peaking capacity to achieve reliability and minimize risk. The Update preferred portfolio includes 20 megawatts of renewable peaking capacity in 2039.

New Nuclear Resources

The 2025 IRP Update preferred portfolio includes the Kemmerer Unit 1 advanced nuclear project, which is a significant source of non-emitting energy.

New Demand-Side Management

DSM resources continue to play a key role in PacifiCorp's resource mix. The 2025 IRP Update preferred portfolio includes 2,612 gigawatt-hours of cumulative energy efficiency savings by the end of 2030, 9,711 gigawatt-hours by the end of 2040 and 11,811 gigawatt-hours by the end of 2045. The Update preferred portfolio also includes 324 megawatts of new demand response capacity by the end of 2030, and 657 megawatts by the end of 2040 and 1,031 megawatts by the end of 2045.

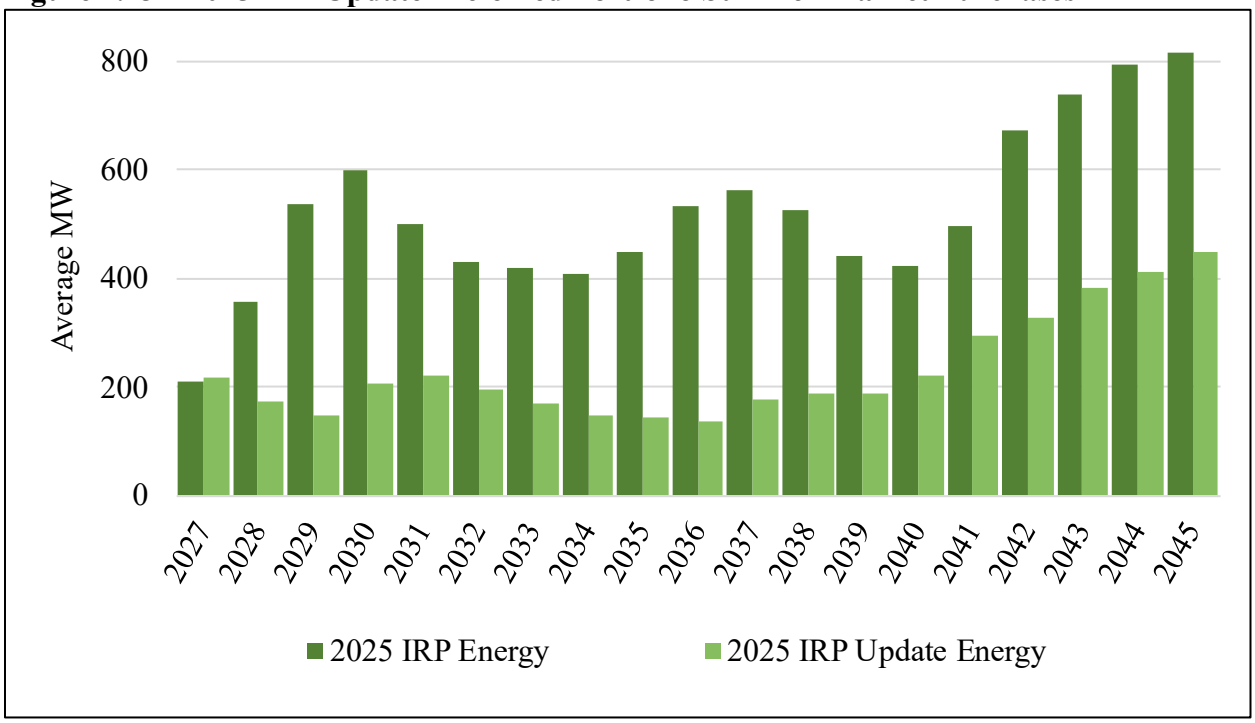
Market Activity

As in the 2025 IRP, PacifiCorp allowed economic purchases enabled by hourly transmission availability throughout the modeling horizon, except for certain key hours.[8] During key hours on the top five load days each month, PacifiCorp allowed zero hourly economic purchases. Hourly economic transactions do not count towards resource adequacy requirements.

Responsive to stakeholder feedback, PacifiCorp allowed block market purchases to count towards firm capacity requirements in the 2025 IRP Update. 500 megawatts of purchase were available each at Mid-C and Wyoming East beginning in 2030. These block purchases generate a flat amount of energy in every hour during July and December, as these are the respective summer and winter months in which capacity requirements are evaluated during portfolio selection. In actual operations market purchases could also be required in additional months during the summer and winter seasons and would vary throughout each year. For additional information on block market purchases, refer to Chapter 5 "Resource Options".

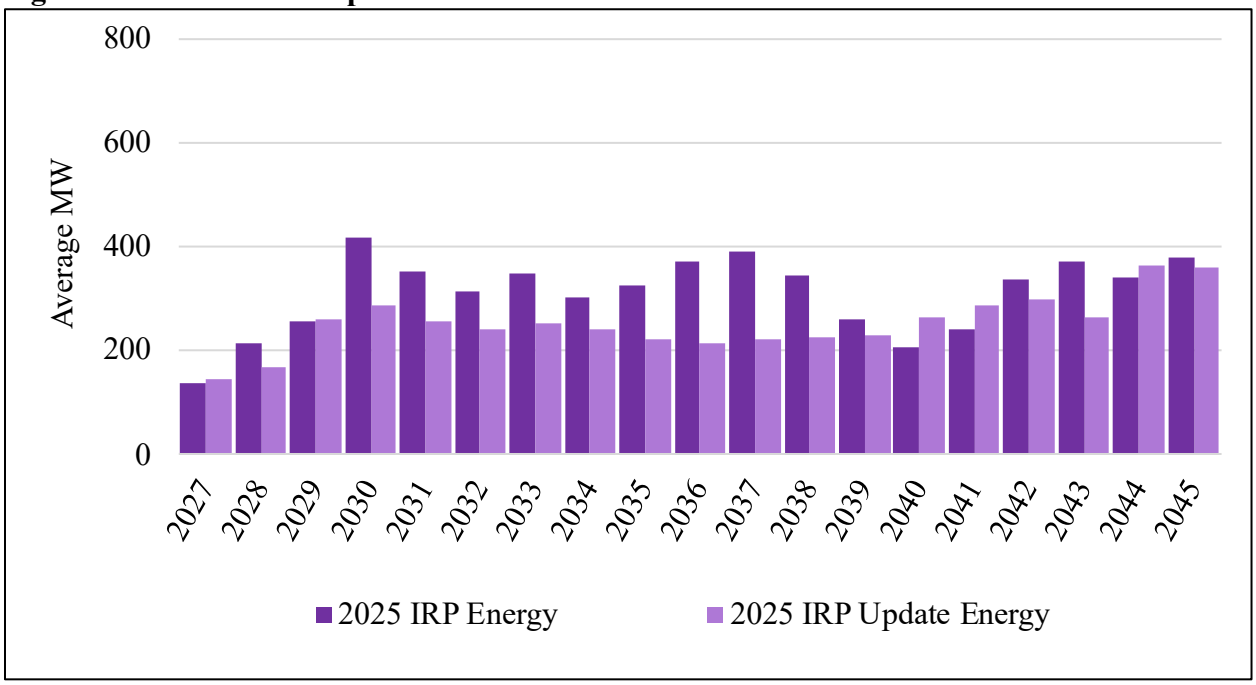
The figures below present only hourly economic purchases for energy selected in the ST model. While the block purchases described above also help to meet energy requirements, block purchases have been omitted from Figure 7.13 and Figure 7.14 as these products were treated on a comparable basis to other proxy resource options and were selected in the LT model to meet both energy and capacity requirements. This results in a slightly under-stated view of the total energy purchases presented below for the 2025 IRP Update, as the energy benefit of block purchases is not shown.

Figure 7.13 – 2025 IRP Update Preferred Portfolio Summer Market Purchases[9,10]



[9] This figure uses ST model results. For market data, it is appropriate to use ST model results because the ST model is run with an hourly granularity which more accurately represents the energy needed to meet load obligations compared to the less granular LT capacity expansion model.
[10] "Summer Market Purchases" includes purchases from June through September.

Figure 7.14 – 2025 IRP Update Preferred Portfolio Winter Market Purchases[3,11]



Coal and Gas Retirements/Gas Conversions

Coal resources have been, and remain, an important resource in PacifiCorp's resource portfolio, fulfilling roles as base load resources, and also as dispatchable support for newer renewable and storage technologies. The operating capabilities of these facilities have adapted to the planning environment, and current indications point to changing roles in the future. PacifiCorp has been able to lower operating minimums and optimize coal dispatch through the Energy Imbalance Market (EIM). This in turn has enabled the company to both reduce fuel consumption and associated costs and emissions by increasingly buying low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. EPA's approval of Wyoming's ozone plan and the stay of EPA's disapproval of Utah's ozone plan results in fewer restrictions on coal-fired operation than have been assumed in the recent past.

Table 7.8 compares coal unit dispositions side-by-side in the 2025 IRP and the 2025 IRP Update.

[11] "Winter Market Purchases" includes purchases from December and January.

Table 7.8 – Coal Unit Retirements in the 2025 IRP and 2025 IRP Update

Coal		
Unit	2025 IRP Retirement Year (1/1/XX)	2025 IRP Update Retirement Year (1/1/XX)
	As Selected	As Selected
Colstrip 3 (1)	2030	2030
Colstrip 4	2030	2030
Craig 1	2026	2026
Craig 2	2029	2029
DaveJohnston 1 (2)	2045+	2040
DaveJohnston 2 (3)	2045+	2044
DaveJohnston 3	2028	2028
DaveJohnston 4	2045+	2045+
Hayden 1	2029	2029
Hayden 2	2028	2028
Hunter 1	2045+	2045+
Hunter 2	2045+	2045+
Hunter 3	2045+	2045+
Huntington 1	2045+	2045+
Huntington 2	2045+	2045+
JimBridger 1	2045+	2045+
JimBridger 2	2045+	2045+
JimBridger 3 (4)	2043	2045+
JimBridger 4 (5)	2043	2045+
Naughton 1 (6)	2043	2040
Naughton 2	2045+	2045+
Wyodak	2045+	2045+

No Change
Change from 2025 IRP

Comparing the 2025 IRP Update to the 2025 IRP, there are six notable changes, keyed to the table entries above:

1. In the 2025 IRP, PacifiCorp modeled its share of Colstrip 3 as expiring at the beginning of 2026, to be replaced by an increase in PacifiCorp's share of Colstrip 4. In the 2025 IRP Update, PacifiCorp maintains a flat share of Colstrip 3 and Colstrip 4 until the retirement of both shares at the beginning of 2030. PacifiCorp's combined share of Colstrip 3 and Colstrip 4 is the same in the 2025 IRP Update as it was in the 2025 IRP.
2. In the 2025 IRP, Dave Johnston 1 was selected for gas conversion in 2029, and this gas conversion continued to operate throughout the horizon. In the 2025 IRP Update, Dave Johnston 1 is still selected for gas conversion in 2029, but the gas converted unit was

selected for retirement at the beginning of 2040. This is viewed as acceptable given the relatively low cost of gas conversion. The Dave Johnston sensitivity study selects continued coal-fired operation of Dave Johnston throughout the horizon.

3. In the 2025 IRP, Dave Johnston 2 was selected for gas conversion in 2029, and this gas conversion continued to operate throughout the horizon. In the 2025 IRP Update, Dave Johnston 2 is still selected for gas conversion in 2029, but the gas converted unit was selected for retirement at the beginning of 2044. This is viewed as acceptable given the relatively low cost of gas conversion.
4. In the 2025 IRP, Jim Bridger Unit 3 installed CCS in 2030 and retired at the beginning of 2042. In the 2025 IRP Update, Jim Bridger 3 installs CCS in 2031 and continues to operate through the end of the modeling horizon.
5. In the 2025 IRP, Jim Bridger Unit 4 installed CCS in 2030 and retired at the beginning of 2042. In the 2025 IRP Update, Jim Bridger 4 installs CCS in 2031 and continues to operate through the end of the modeling horizon.
6. In the 2025 IRP, Naughton 1 underwent gas conversion in 2026 and continued to operate until the beginning of 2043. In the 2025 IRP Update, Naughton 1 starts the modeling horizon as a gas-converted unit and continues to operate until it is selected for retirement at the beginning of 2040.

Table 7.9 and 7.10 report summer and winter load and resource capacity balances.

Table 7.9 – 2025 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

East	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Coal	3,592	3,407	3,133	3,133	2,866	2,866	2,866	2,866	2,866	2,866
Gas	3,360	3,360	3,534	3,535	3,535	3,535	3,535	3,535	3,535	3,535
Hydroelectric	75	75	75	75	75	75	75	75	75	75
Wind	545	545	544	535	521	521	521	520	520	520
Solar	602	596	590	584	577	571	565	559	552	546
Other Renewable	48	48	47	47	46	46	45	45	44	44
Storage	844	834	824	815	806	796	787	777	767	758
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	400	391	382	373	364	353	340	328	318	295
Demand Response	413	410	407	403	400	397	393	390	387	383
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,440)	(1,168)	(1,125)	(756)	(841)	(755)	(679)	(680)	(700)	(718)
East Existing Resources	**8,439**	**8,497**	**8,411**	**8,742**	**8,348**	**8,403**	**8,447**	**8,413**	**8,364**	**8,304**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Annual Block Product	0	0	0	0	106	104	172	229	320	320
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	1	3	3	21	533
Wind	0	0	3	3	3	3	3	3	3	3
Solar	0	0	3	186	183	180	178	175	173	170
Storage	2	2	2	4	120	119	118	117	115	114
Other Renewable	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	1	1
Demand Response	3	4	121	142	149	156	162	170	177	186
East Planned Resources	**5**	**6**	**128**	**334**	**561**	**563**	**636**	**696**	**810**	**1,328**
East Total Resources	**8,444**	**8,503**	**8,540**	**9,076**	**8,909**	**8,966**	**9,082**	**9,109**	**9,174**	**9,632**
Load	7,825	7,999	8,161	8,329	8,542	8,562	8,764	8,987	9,242	9,549
Distributed Generation	(143)	(191)	(242)	(297)	(356)	(261)	(297)	(330)	(361)	(392)
Energy Efficiency	(163)	(237)	(314)	(399)	(496)	(629)	(682)	(796)	(911)	(979)
East Total obligation	**7,519**	**7,571**	**7,604**	**7,633**	**7,690**	**7,672**	**7,784**	**7,861**	**7,970**	**8,178**
East Reserve Margin	12.3%	12.3%	12.3%	18.9%	15.9%	16.9%	16.7%	15.9%	15.1%	17.8%
West										
Coal	97	97	97	0	0	0	0	0	0	0
Gas	681	681	681	681	681	681	681	681	681	681
Hydroelectric	710	710	710	710	710	710	710	710	710	710
Wind	39	39	39	39	39	39	39	39	39	39
Solar	71	70	69	69	65	65	65	65	65	65
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	1	1	1	1	1	1	1	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	230	226	219	215	209	200	196	193	189	184
Demand Response	16	16	16	16	15	15	15	15	15	14
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	1,440	1,168	1,125	756	841	755	679	680	700	718
West Existing Resources	**3,285**	**3,007**	**2,957**	**2,486**	**2,561**	**2,466**	**2,385**	**2,382**	**2,398**	**2,410**
Additional Proxy/Short-Term Purchases	983	494	419	0	0	0	0	0	0	0
Annual Block Product	0	0	0	0	106	104	172	229	320	320
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	40	225	225	225	225	226	239	248
Solar	0	133	191	434	417	401	384	375	368	363
Storage	1	636	722	1,211	1,323	1,669	1,837	1,874	1,897	1,932
Other Renewable	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	2	16	19	19	19	19	23	25	28	28
West Planned Resources	**987**	**1,278**	**1,390**	**1,889**	**2,090**	**2,418**	**2,641**	**2,729**	**2,853**	**2,891**
West Total Resources	**4,272**	**4,285**	**4,347**	**4,375**	**4,651**	**4,884**	**5,027**	**5,111**	**5,251**	**5,302**
Load	3,972	4,050	4,171	4,267	4,502	4,693	4,807	4,890	4,987	5,090
Distributed Generation	(59)	(82)	(108)	(136)	(166)	(107)	(123)	(139)	(154)	(168)
Energy Efficiency	(110)	(151)	(192)	(235)	(289)	(330)	(361)	(403)	(443)	(486)
West Total obligation	**3,804**	**3,816**	**3,871**	**3,896**	**4,047**	**4,256**	**4,323**	**4,348**	**4,391**	**4,436**
West Reserve Margin	12.3%	12.3%	12.3%	12.3%	14.9%	14.7%	16.3%	17.6%	19.6%	19.5%
System										
Total Resources	12,716	12,788	12,887	13,451	13,560	13,850	14,109	14,220	14,425	14,933
Obligation	11,323	11,387	11,475	11,529	11,737	11,928	12,107	12,209	12,360	12,615
Planning Reserves (12.3%)	1,393	1,401	1,411	1,418	1,444	1,467	1,489	1,502	1,520	1,552
Obligation + Reserves	12,716	12,788	12,887	12,947	13,181	13,396	13,596	13,710	13,881	14,166
System Position	0	0	0	504	380	455	513	510	544	767
Reserve Margin	**12.3%**	**12.3%**	**12.3%**	**16.7%**	**15.5%**	**16.1%**	**16.5%**	**16.5%**	**16.7%**	**18.4%**

Table 7.9 (Cont.) – 2025 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

East	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,866	2,866	2,866	2,866	2,866	2,866	2,866	2,866	2,866
Gas	3,535	3,535	3,535	3,322	3,322	3,322	3,322	3,234	3,234
Hydroelectric	75	75	75	75	75	75	75	75	75
Wind	520	520	519	519	463	462	462	462	462
Solar	509	503	498	492	487	481	476	451	446
Other Renewable	43	11	11	10	9	9	8	8	0
Storage	748	739	730	720	711	702	692	683	674
Purchase	0	0	0	0	0	0	0	0	0
Qualifying Facilities	243	234	226	214	207	199	192	185	178
Demand Response	380	377	373	370	367	363	360	357	353
Sale	0	0	0	0	0	0	0	0	0
Transfers	(636)	(720)	(551)	0	0	0	0	(1)	(41)
East Existing Resources	**8,283**	**8,140**	**8,281**	**8,589**	**8,506**	**8,480**	**8,454**	**8,318**	**8,246**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	35	0	0	0
Annual Block Product	320	320	320	320	320	320	320	320	320
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0
Gas	533	894	894	894	894	943	1,582	1,582	2,168
Wind	13	45	110	110	108	107	156	154	153
Solar	168	165	163	160	157	155	271	266	262
Storage	113	112	111	110	109	108	107	106	105
Other Renewable	0	0	0	0	0	0	0	0	0
Nuclear	1	1	1	1	1	1	1	1	2
Demand Response	183	205	215	226	238	247	251	246	241
East Planned Resources	**1,331**	**1,743**	**1,815**	**1,821**	**1,828**	**1,915**	**2,688**	**2,676**	**3,250**
East Total Resources	**9,614**	**9,883**	**10,096**	**10,410**	**10,334**	**10,395**	**11,142**	**10,994**	**11,496**
Load	9,813	10,102	10,370	10,649	10,943	11,252	11,556	11,837	12,133
Distributed Generation	(421)	(450)	(478)	(505)	(533)	(559)	(585)	(610)	(636)
Energy Efficiency	(1,072)	(1,186)	(1,284)	(1,365)	(1,457)	(1,436)	(1,526)	(1,546)	(1,574)
East Total obligation	**8,319**	**8,466**	**8,608**	**8,778**	**8,953**	**9,257**	**9,444**	**9,681**	**9,924**
East Reserve Margin	15.6%	16.7%	17.3%	18.6%	15.4%	12.3%	18.0%	13.6%	15.8%
West									
Coal	0	0	0	0	0	0	0	0	0
Gas	681	681	681	681	681	681	681	681	681
Hydroelectric	710	710	710	710	710	710	710	710	710
Wind	39	39	39	39	39	39	39	39	39
Solar	65	65	65	65	25	25	25	25	25
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0
Qualifying Facilities	168	164	159	156	152	149	136	132	128
Demand Response	14	14	14	14	13	13	13	13	12
Sale	0	0	0	0	0	0	0	0	0
Transfers	636	720	551	0	0	0	0	1	41
West Existing Resources	**2,312**	**2,391**	**2,218**	**1,664**	**1,621**	**1,617**	**1,604**	**1,601**	**1,636**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0
Annual Block Product	320	320	320	320	320	320	320	320	320
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0
Wind	272	271	319	319	318	318	317	317	317
Solar	448	436	420	396	372	347	368	340	312
Storage	1,993	1,989	2,181	3,011	3,095	3,238	3,464	3,560	3,674
Other Renewable	0	0	20	20	20	20	20	20	20
Nuclear	0	0	0	0	0	0	0	0	0
Demand Response	28	30	31	31	30	30	30	41	41
West Planned Resources	**3,061**	**3,047**	**3,292**	**4,096**	**4,155**	**4,273**	**4,519**	**4,597**	**4,684**
West Total Resources	**5,373**	**5,438**	**5,509**	**5,760**	**5,776**	**5,890**	**6,123**	**6,198**	**6,321**
Load	5,224	5,328	5,437	5,544	5,667	5,905	5,972	6,083	6,214
Distributed Generation	(183)	(197)	(211)	(225)	(240)	(254)	(267)	(281)	(295)
Energy Efficiency	(541)	(573)	(605)	(631)	(665)	(747)	(561)	(568)	(576)
West Total obligation	**4,500**	**4,558**	**4,621**	**4,688**	**4,762**	**4,904**	**5,144**	**5,234**	**5,343**
West Reserve Margin	19.4%	19.3%	19.2%	22.9%	21.3%	20.1%	19.0%	18.4%	18.3%
System									
Total Resources	14,987	15,322	15,605	16,170	16,110	16,286	17,265	17,192	17,817
Obligation	12,819	13,023	13,228	13,466	13,715	14,161	14,588	14,915	15,267
Planning Reserves (12.3%)	1,577	1,602	1,627	1,656	1,687	1,742	1,794	1,835	1,878
Obligation + Reserves	14,396	14,625	14,855	15,122	15,402	15,903	16,382	16,750	17,145
System Position	591	696	750	1,047	708	383	882	442	672
Reserve Margin	**16.9%**	**17.6%**	**18.0%**	**20.1%**	**17.5%**	**15.0%**	**18.3%**	**15.3%**	**16.7%**

Table 7.10 – 2025 IRP Update Winter Capacity Load and Resource Balance (Megawatts)

East	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Coal	3,705	3,481	3,184	3,183	2,906	2,906	2,906	2,906	2,906	2,906
Gas	3,405	3,405	3,596	3,597	3,597	3,597	3,597	3,597	3,597	3,597
Hydroelectric	32	32	32	32	32	32	32	32	32	32
Wind	1,081	1,081	1,081	1,058	1,018	1,018	1,018	1,018	1,018	1,018
Solar	156	154	153	151	149	147	146	144	142	141
Other Renewable	44	44	43	43	42	42	41	41	40	40
Storage	577	567	558	549	539	529	520	510	501	492
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	178	173	168	163	158	151	142	126	122	114
Demand Response	139	139	139	139	139	139	139	139	139	139
Sale	0	0	0	0	0	0	0	0	0	0
Transfers	(1,600)	(1,600)	(1,593)	(1,004)	(1,040)	(845)	(720)	(697)	(699)	(740)
East Existing Resources	**7,716**	**7,477**	**7,361**	**7,910**	**7,542**	**7,718**	**7,822**	**7,817**	**7,799**	**7,739**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Annual Block Product	0	0	0	0	106	104	172	229	320	320
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	1	3	3	21	533
Wind	0	0	4	4	4	3	3	3	3	4
Solar	0	0	0	52	51	50	49	48	47	46
Storage	1	1	2	3	71	71	70	69	68	68
Other Renewable	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	1	1
Demand Response	0	0	0	0	0	0	0	1	1	1
East Planned Resources	**2**	**2**	**6**	**59**	**232**	**230**	**298**	**353**	**462**	**972**
East Total Resources	**7,718**	**7,478**	**7,366**	**7,969**	**7,774**	**7,947**	**8,120**	**8,170**	**8,260**	**8,711**
Load	5,984	6,104	6,245	6,350	6,536	6,705	6,946	7,166	7,399	7,605
Distributed Generation	(2)	(3)	(4)	(5)	(6)	(8)	(9)	(9)	(10)	(11)
Energy Efficiency	(119)	(162)	(205)	(251)	(302)	(367)	(426)	(494)	(560)	(605)
East Total obligation	**5,862**	**5,938**	**6,036**	**6,094**	**6,228**	**6,330**	**6,512**	**6,662**	**6,828**	**6,989**
East Reserve Margin	31.7%	25.9%	22.0%	30.8%	24.8%	25.5%	24.7%	22.6%	21.0%	24.6%
West										
Coal	132	132	132	0	0	0	0	0	0	0
Gas	719	719	719	719	719	719	719	719	719	719
Hydroelectric	728	728	728	728	728	728	728	728	728	728
Wind	41	41	41	41	41	41	41	41	41	41
Solar	6	6	6	5	4	4	4	4	4	4
Other Renewable	0	0	0	0	0	0	0	0	0	0
Storage	1	1	1	1	1	1	1	0	0	0
Purchase	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	64	63	61	61	60	59	59	58	58	56
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	1,593	1,004	1,040	845	720	697	699	740
West Existing Resources	**3,291**	**3,290**	**3,281**	**2,560**	**2,593**	**2,398**	**2,273**	**2,249**	**2,250**	**2,289**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0	0
Annual Block Product	0	0	0	0	106	104	172	229	320	320
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	34	189	188	188	188	189	200	208
Solar	0	11	15	35	33	32	30	29	29	28
Storage	1	685	778	1,302	1,418	1,774	1,949	1,991	2,012	2,049
Other Renewable	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Demand Response	0	0	12	57	59	67	68	70	71	72
West Planned Resources	**2**	**697**	**838**	**1,583**	**1,805**	**2,166**	**2,408**	**2,507**	**2,632**	**2,678**
West Total Resources	**3,293**	**3,987**	**4,120**	**4,142**	**4,398**	**4,564**	**4,680**	**4,756**	**4,882**	**4,967**
Load	3,671	3,743	3,865	3,943	4,135	4,342	4,442	4,515	4,603	4,735
Distributed Generation	(1)	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(2)	(2)
Energy Efficiency	(98)	(152)	(208)	(266)	(325)	(384)	(440)	(495)	(553)	(610)
West Total obligation	**3,572**	**3,590**	**3,656**	**3,676**	**3,809**	**3,957**	**4,000**	**4,017**	**4,048**	**4,123**
West Reserve Margin	-7.8%	11.1%	12.7%	12.7%	15.5%	15.3%	17.0%	18.4%	20.6%	20.5%
System										
Total Resources	11,011	11,465	11,486	12,111	12,172	12,511	12,800	12,926	13,142	13,678
Obligation	9,434	9,528	9,692	9,769	10,037	10,287	10,512	10,680	10,876	11,112
Planning Reserves (12.7%)	1,198	1,210	1,231	1,241	1,275	1,306	1,335	1,356	1,381	1,411
Obligation + Reserves	10,632	10,738	10,922	11,010	11,311	11,594	11,847	12,036	12,257	12,523
System Position	379	727	564	1,101	861	918	953	890	885	1,155
Reserve Margin	**16.7%**	**20.3%**	**18.5%**	**24.0%**	**21.3%**	**21.6%**	**21.8%**	**21.0%**	**20.8%**	**23.1%**

Table 7.10 (Cont.) - 2025 IRP Update Winter Capacity Load and Resource Balance (Megawatts)

East	2037	2038	2039	2040	2041	2042	2043	2044	2045
Coal	2,906	2,906	2,906	2,906	2,906	2,906	2,906	2,906	2,906
Gas	3,597	3,597	3,597	3,381	3,381	3,381	3,381	3,278	3,278
Hydroelectric	32	32	32	32	32	32	32	32	32
Wind	1,018	1,018	1,018	1,018	924	924	924	924	924
Solar	137	136	134	132	131	129	127	118	117
Other Renewable	39	8	8	8	7	6	6	5	0
Storage	482	472	463	454	444	435	425	416	406
Purchase	0	0	0	0	0	0	0	0	0
Qualifying Facilities	100	95	92	88	84	80	76	73	69
Demand Response	139	139	139	139	139	139	139	139	139
Sale	0	0	0	0	0	0	0	0	0
Transfers	(700)	(738)	(547)	0	0	0	0	0	0
East Existing Resources	**7,752**	**7,667**	**7,842**	**8,158**	**8,048**	**8,032**	**8,017**	**7,892**	**7,872**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0
Annual Block Product	320	320	320	320	320	320	320	320	320
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0
Gas	533	894	894	894	894	943	1,582	1,582	2,168
Wind	12	35	83	81	80	78	111	108	106
Solar	45	44	43	42	41	39	67	65	63
Storage	67	66	65	65	64	63	62	62	61
Other Renewable	0	0	0	0	0	0	0	0	0
Nuclear	1	1	1	1	1	1	1	1	2
Demand Response	1	5	5	5	5	5	4	4	58
East Planned Resources	**979**	**1,366**	**1,412**	**1,408**	**1,404**	**1,449**	**2,148**	**2,143**	**2,778**
East Total Resources	**8,731**	**9,032**	**9,254**	**9,566**	**9,452**	**9,482**	**10,166**	**10,035**	**10,650**
Load	7,902	8,151	8,440	8,687	8,941	9,263	9,560	9,853	10,155
Distributed Generation	(11)	(12)	(13)	(13)	(13)	(14)	(14)	(15)	(15)
Energy Efficiency	(669)	(730)	(785)	(836)	(895)	(903)	(965)	(997)	(1,044)
East Total obligation	**7,221**	**7,409**	**7,643**	**7,838**	**8,033**	**8,346**	**8,581**	**8,841**	**9,096**
East Reserve Margin	20.9%	21.9%	21.1%	22.0%	17.7%	13.6%	18.5%	13.5%	17.1%
West									
Coal	0	0	0	0	0	0	0	0	0
Gas	719	719	719	720	720	720	720	720	720
Hydroelectric	728	728	728	728	728	728	728	728	728
Wind	41	41	41	41	41	41	41	41	41
Solar	4	4	4	4	2	2	2	2	2
Other Renewable	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0
Purchase	0	0	0	0	0	0	0	0	0
Qualifying Facilities	55	55	54	53	52	52	51	50	50
Demand Response	0	0	0	0	0	0	0	0	0
Sale	0	0	0	0	0	0	0	0	0
Transfers	700	738	547	0	0	0	0	0	0
West Existing Resources	**2,248**	**2,286**	**2,094**	**1,547**	**1,543**	**1,543**	**1,542**	**1,541**	**1,541**
Additional Proxy/Short-Term Purchases	0	0	0	0	0	0	0	0	0
Annual Block Product	320	320	320	320	320	320	320	320	320
Hydrogen Storage Peaker	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0
Wind	227	227	267	267	266	266	266	265	265
Solar	34	33	31	29	27	25	26	23	21
Storage	2,114	2,108	2,313	3,205	3,295	3,445	3,687	3,784	3,900
Other Renewable	0	0	20	20	20	20	20	20	20
Nuclear	0	0	0	0	0	0	0	0	0
Demand Response	74	75	77	78	83	84	84	93	93
West Planned Resources	**2,769**	**2,764**	**3,028**	**3,919**	**4,011**	**4,159**	**4,403**	**4,505**	**4,619**
West Total Resources	**5,018**	**5,050**	**5,122**	**5,466**	**5,555**	**5,702**	**5,944**	**6,046**	**6,160**
Load	4,824	4,900	5,009	5,124	5,235	5,389	5,509	5,608	5,738
Distributed Generation	(3)	(3)	(3)	(3)	(3)	(3)	(4)	(4)	(4)
Energy Efficiency	(653)	(700)	(746)	(802)	(843)	(884)	(767)	(784)	(801)
West Total obligation	**4,168**	**4,197**	**4,261**	**4,319**	**4,389**	**4,501**	**4,739**	**4,820**	**4,933**
West Reserve Margin	20.4%	20.3%	20.2%	26.6%	26.6%	26.7%	25.4%	25.4%	24.9%
System									
Total Resources	13,748	14,082	14,376	15,032	15,007	15,184	16,110	16,081	16,810
Obligation	11,390	11,606	11,904	12,157	12,422	12,847	13,320	13,661	14,029
Planning Reserves (12.7%)	1,447	1,474	1,512	1,544	1,578	1,632	1,692	1,735	1,782
Obligation + Reserves	12,836	13,080	13,415	13,701	14,000	14,479	15,012	15,396	15,811
System Position	912	1,002	961	1,331	1,007	705	1,098	685	999
Reserve Margin	**20.7%**	**21.3%**	**20.8%**	**23.6%**	**20.8%**	**18.2%**	**20.9%**	**17.7%**	**19.8%**

Carbon Dioxide Emissions

The 2025 IRP Update preferred portfolio reflects PacifiCorp's on-going efforts to provide valuable energy solutions for all its customers and comply with state-specific carbon dioxide (CO_2) and other carbon dioxide equivalent (CO_2e) emissions reductions requirements.

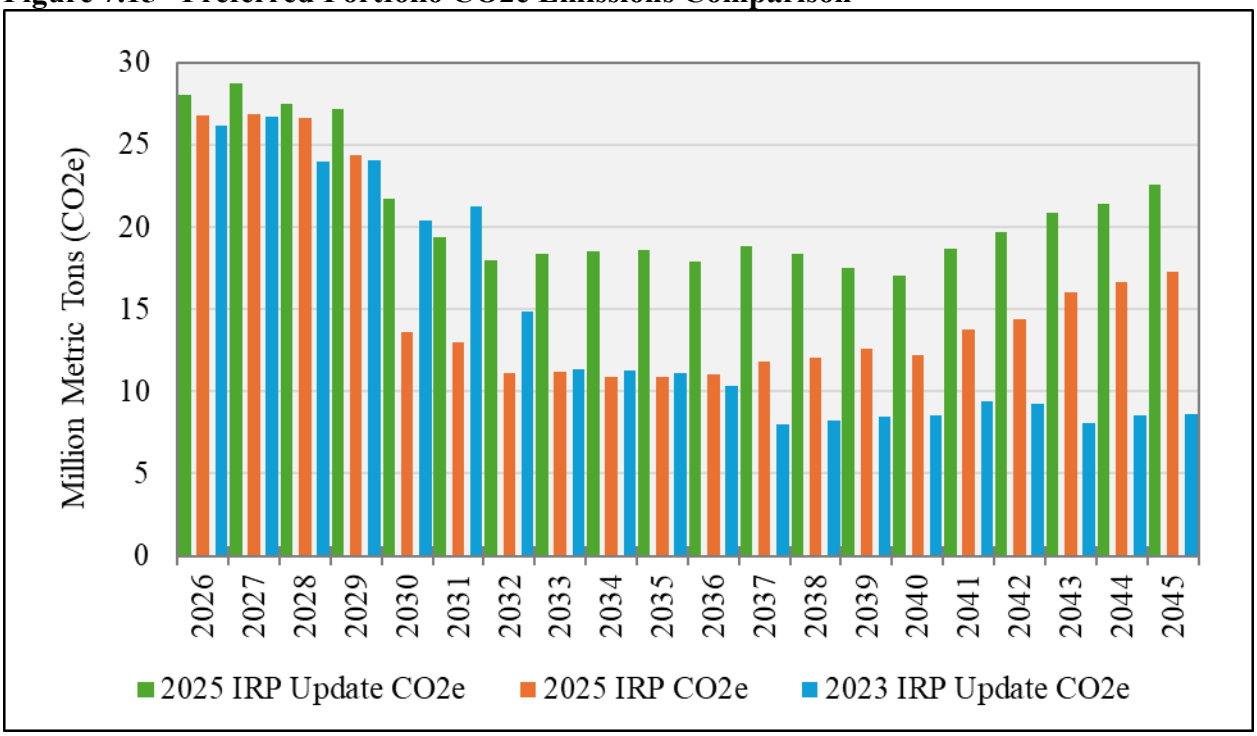
PacifiCorp's total system emissions[12] have been declining and will continue to decline until 2030 largely due to participation in the EIM and a commitment to CAISO's Extended Day-Ahead Market (EDAM), which reduces customer costs and maximizes use of non-emitting renewable resources that have no fuel cost and may generate tax credits.

The chart below in Figure 7.15 compares projected annual CO_2e emissions between the 2025 IRP Update and 2025 IRP preferred portfolios. In this graph, emissions are assigned to market purchases at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour.

The 2025 IRP Update preferred portfolio continues to show a continued downward trajectory in emissions over the near term; however, emissions are higher than projected in the 2025 IRP. This is primarily attributable to changes in federal policy since the 2025 IRP that have increased the cost of renewable resources. Further, over the longer-term, the load forecast in the 2025 IRP Update is higher than in the 2025 IRP.

[12] There is stakeholder interest in breaking out state-specific emissions in the 2027 IRP. This has not been done for the 2025 IRP Update, but PacifiCorp is committed to developing a reasonable methodology for the 2027 filing. See Appendix G, stakeholder feedback form #16 (Utah Clean Energy, et al.)

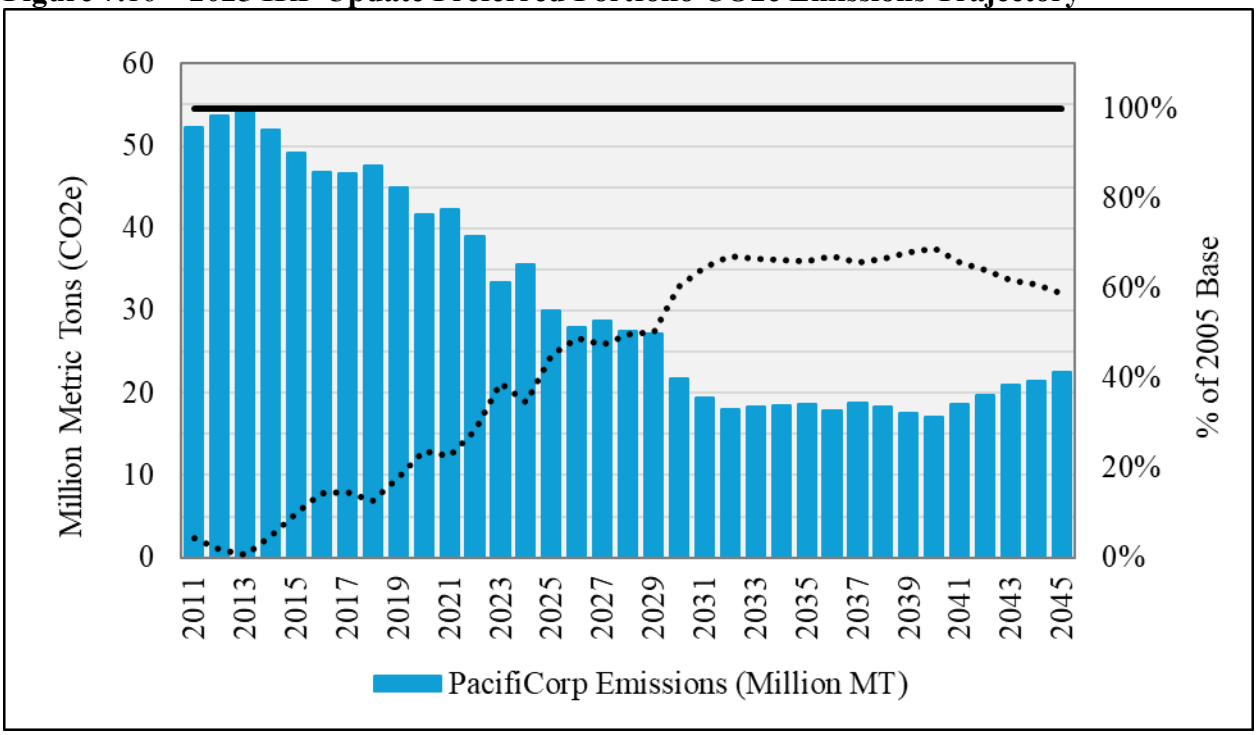
Figure 7.15 –Preferred Portfolio CO2e Emissions Comparison*



* From 2026 through the end of the twenty-year planning period in 2045, emissions reflect those from the 2025 IRP Update preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/megawatt-hour). Emissions from sales are not removed.

Figure 7.16 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per megawatt-hour to market purchases (with no credit to market sales) and includes emissions associated with specified purchases. This graph demonstrates that relative to a 2005 baseline of 54.6 million metric tons, system CO_2e emissions are down 45% in 2025, 60% in 2030, 66% in 2035, 69% in 2040, and 59% in 2045.

Figure 7.16 – 2025 IRP Update Preferred Portfolio CO2e Emissions Trajectory[1]



[1] PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2024 from owned facilities, specified sources and unspecified sources. Emissions in 2025 reflect results from the 2025 IRP preferred portfolio. After 2025, emissions reflect results from the 2025 IRP Update preferred portfolio.

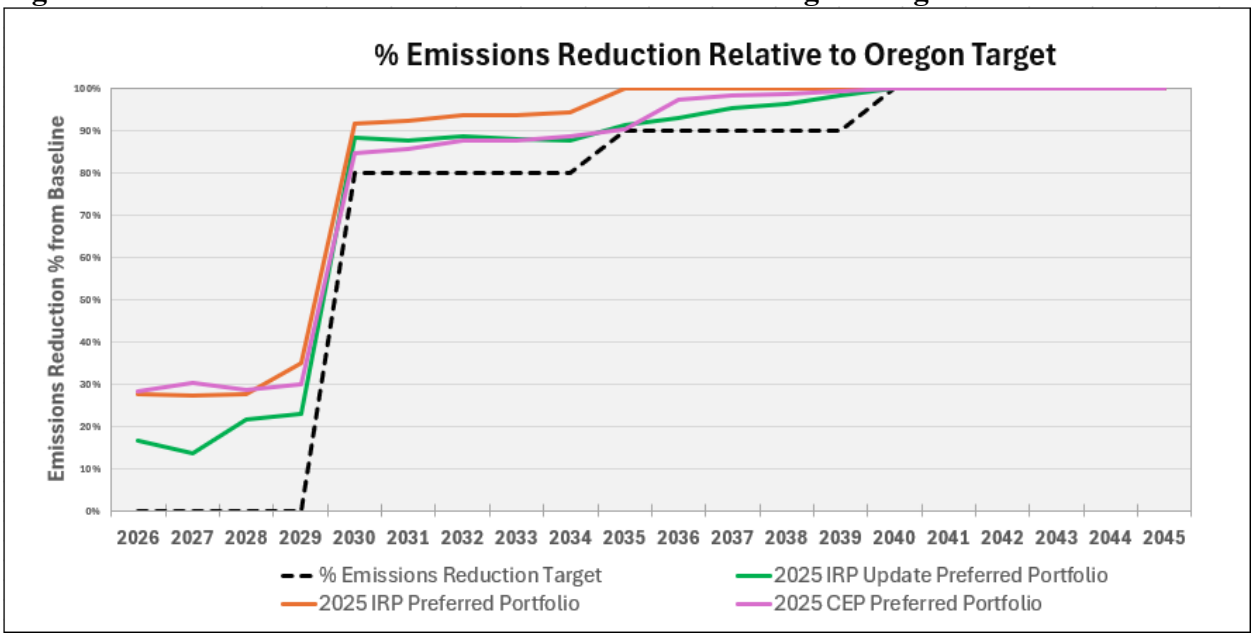
Oregon House Bill 2021 Compliance

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 (CO2e) to 1.79 MMT CO2e by 2030, 0.89 MMT CO2e 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 Update 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.

Figure 7.17 reports a comparison of recent studies regarding Oregon emissions reduction position. While the percentage reduction varies across studies, all reflect a compliance trajectory reasonably aligned with targets.

Figure 7.17 – Percent Emissions Reduction Relative to Oregon Target



Renewable Portfolio Standards

Figure 7.18 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the 2025 IRP Update preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

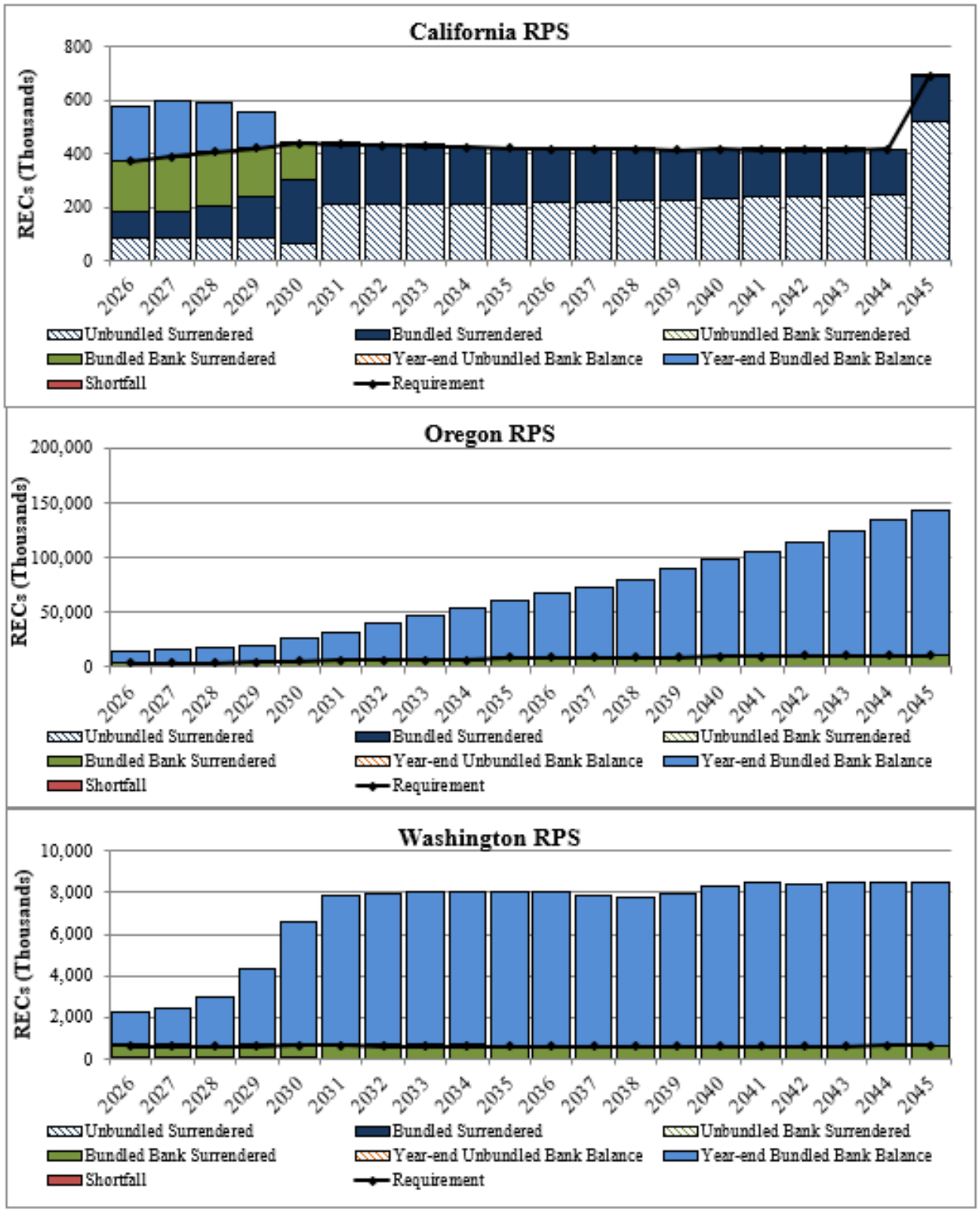
The California RPS compliance position will be met through year 2030 with owned and contracted renewable resources, as well as REC purchases. Beyond 2030, the company may need to purchase approximately ~200,000 unbundled RECs per year on a long-term contract to meet the RPS target of 60% in years where a shortfall is projected. Alternatively, PacifiCorp may consider the acquisition of new renewable resources to meet California's RPS. In 2045, California's RPS target increases to 100%.

Oregon RPS compliance is achieved through 2045 with the addition of new renewable resources in the 2025 IRP Update preferred portfolio.

Under PacifiCorp's 2026 Protocol Washington's RPS position is improved by receiving a system share of renewable resources across PacifiCorp's system, and there are no anticipated shortfalls.

While not shown in Figure 7.18, PacifiCorp meets the Utah 2025 state target to supply 20% of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources.

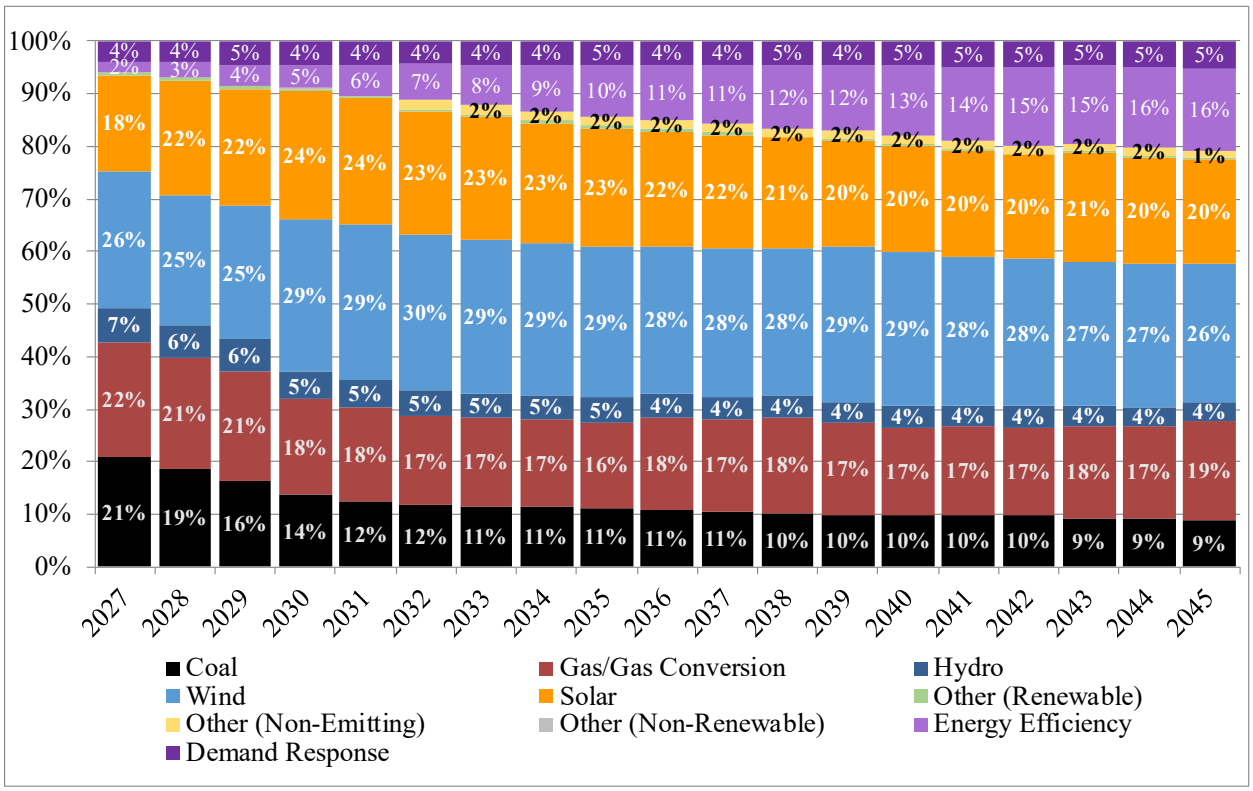
Figure 7.18 – Annual State RPS Compliance Forecast



Projected Capacity Mix

Figure 7.19 shows how PacifiCorp's capacity mix is expected to change over time. Coal capacity drops to 19% of the system in 2028, then further to 12% of the system starting in 2031, and finally to 9% of capacity in 2043. Coal capacity is primarily replaced by renewables, natural gas and energy efficiency that increase in contribution over time.

Figure 7.19 – Projected Capacity Mix with 2025 IRP Update Preferred Portfolio Resources*

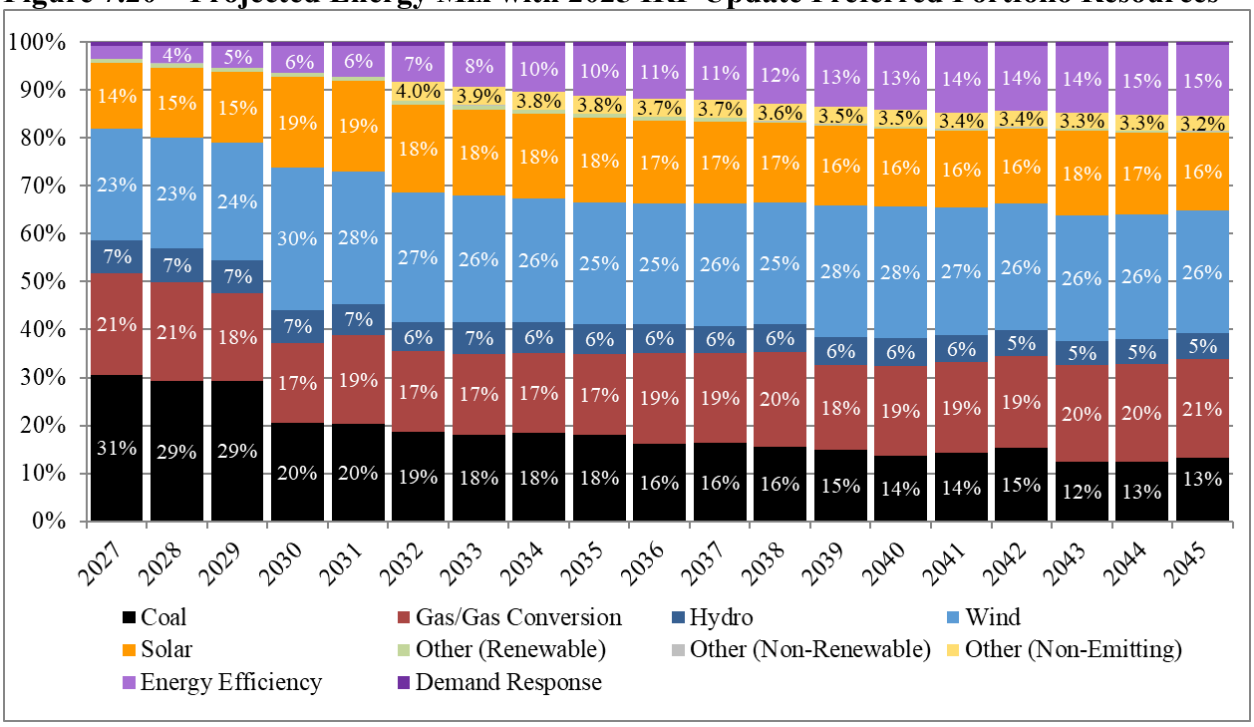


* Storage resources are excluded as they do not provide net capacity.

Projected Energy Mix

Figure 7.20 shows how PacifiCorp's energy mix is expected to change over time. Coal generation drops to 20% of the total system generation in 2030, then further to 15% of the total system generation or lower from 2040 through 2045. Coal generation is primarily replaced by renewables, natural gas and energy efficiency that increase in contribution over time.

Figure 7.20 – Projected Energy Mix with 2025 IRP Update Preferred Portfolio Resources*



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

Eligible Variant Portfolios

PacifiCorp selected its updated preferred portfolio from among the set of eligible studies, including the key variants describes here. These eligible variants focus on critical decision variables addressing areas of interest and change. The economics of these studies provide further support for the selection of the updated preferred portfolio.

Eligible studies are those which introduce specific additional constraints or requirements for evaluation, but retain initial conditions aligned with the best available forecast data, regulatory requirements and operational realities. For example, the "No Future Technology" variant (below) is modeled with a more limited set of traditional resource options, avoiding emergent technology such as advanced nuclear or 100-hour battery storage. If this study resulted in the least-cost, least-risk portfolio among all eligible portfolios, it could be selected as the preferred portfolio.

In general, while these variant portfolios are eligible, they are not usually selected for the preferred portfolio as they are not least-cost, least-risk compared to the expected case portfolio. At a high level, if an eligible variant portfolio solution is competitive to be the preferred portfolio, then the expected case base model optimization would have reached that same solution on its own, possibly generating a portfolio that is identical to the variant study. However, there are steps in the optimization process that create opportunities for variants to take the lead, such as the stochastic analysis, which adds an additional risk factor.

Table 7.11 presents eligible variants included in the 2025 IRP Update. Eligible variants are presented below, with additional analysis provided in Chapter 9 relevant to alternative path analysis.

Table 7.11 – Eligible Variant Studies

Eligible Study Name	Description
Hunter Retire	Require all Hunter units to be retired on 1/1/2031
All Coal Retire	Require all existing coal plants to be retired on 1/1/2032
No Future Technology	No nuclear, hydrogen storage, 100-hour storage, or biodiesel peaking
No Kemmerer Unit 1	Kemmerer Unit 1 cannot be selected
No CCS	No coal units are allowed to select CCS technology
HH	An expansion portfolio optimized under the HH price-policy scenario
LN	An expansion portfolio optimized under the LN price-policy scenario

Hunter Retire
This study requires that all three Hunter units retire on 1/1/2031. There is no pipeline available at Hunter, so these units cannot convert to gas. This study shows PacifiCorp's best path forward if it needed to retire all three Hunter units.

All Coal Retire
This study requires that all existing coal plants retire on 1/1/2032. It exhibits how PacifiCorp could respond to changes in the planning environment that would result in all coal plants ceasing coal-fired operation.

No Future Technology
This study removes nuclear, hydrogen storage, 100-hour iron air battery, and biodiesel peaking resources as options. This study shows PacifiCorp's best path forward if none of these technologies were able to meet their expected trajectory.

No Kemmerer Unit 1
This study removes Kemmerer Unit 1 as an option. It shows PacifiCorp's best path if Kemmerer Unit 1 were no longer available.

No CCS
This study removes carbon capture and sequestration as an option for any coal plant on PacifiCorp's system. It shows PacifiCorp's best path in the absence of the installation of carbon capture and sequestration at Jim Bridger units 3 and 4.

HH
This study is optimized under the HH price-policy scenario. It shows PacifiCorp's best path if significant changes to the planning environment result in higher coal and gas fuel costs as well as higher market prices.

LN
This study is optimized under the LN price-policy scenario. It shows PacifiCorp's best path if significant changes to the planning environment result in lower gas fuel costs and lower market prices.

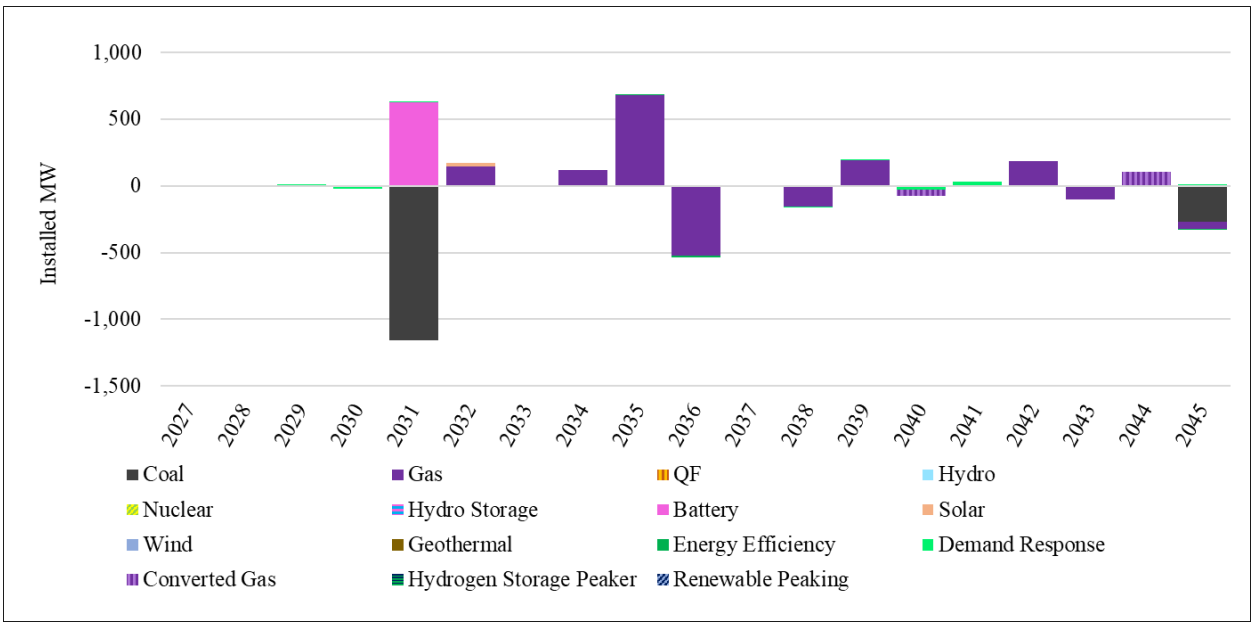
Sensitivities

In contrast to eligible variant studies, sensitivity outcomes are not considered eligible for preferred portfolio selection at this time. Sensitivities can provide additional insight into alternative path analysis and the preferred portfolio and are analyzed in Chapters 8 and 9.

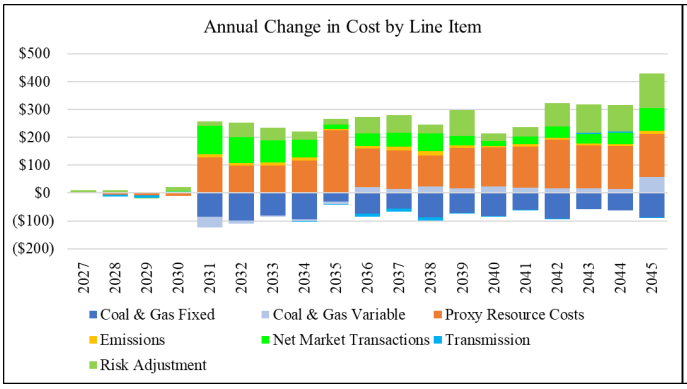
Eligible Variant Results and Analysis

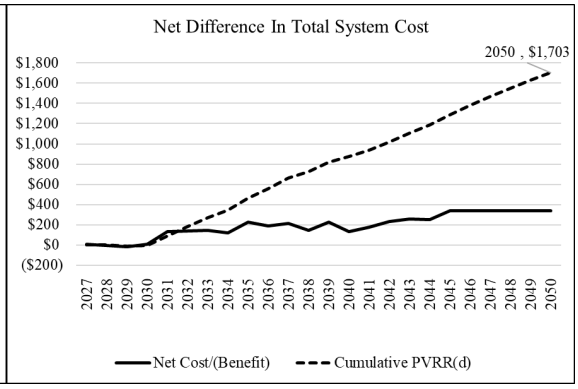
Hunter Retire

The Hunter Retire variant requires the entire Hunter plant to retire by 2031. This portfolio replaces 1,158 MW of lost Hunter capacity with 623 MW of battery storage, 484 MW of new gas peaking units with 940 MW accelerated forward from 2036 and 2038, 32 MW of small-scale solar, and continued operation of the gas converted Dave Johnston Unit 2.. A comparison of the Hunter Retire and Preferred Portfolio resource selections is below:



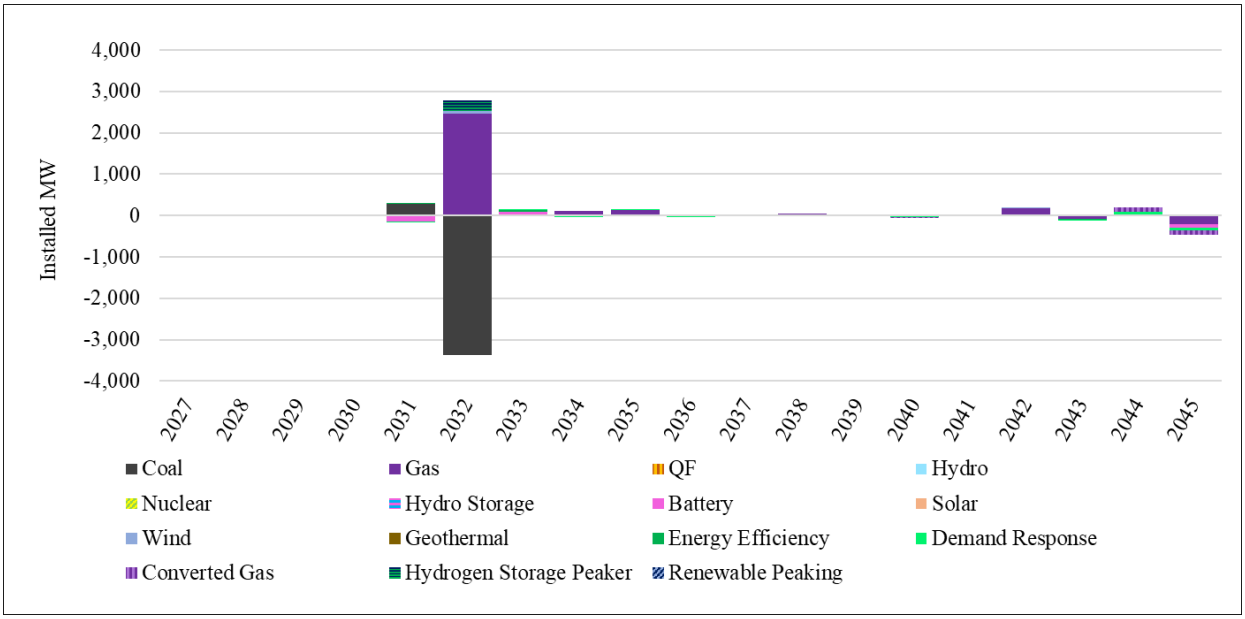
The Hunter Retire portfolio is $1.7 billion more expensive than the preferred portfolio . The reduction in coal fuel and VOM is entirely offset by an increase in gas fuel costs, and $373 million in additional market reliance makes up the majority of the rest of the variable cost increase. The reduction in coal fixed costs is offset by higher proxy capital and fixed costs for the replacement of coal fired resources. Unlike the No CCS and All Coal Retire cases, the Hunter Retire case does not have cost savings due to forgone capital improvements, and while it is closer in cost to the preferred portfolio than retiring all coal, the Hunter Retire portfolio has a larger risk adjustment than either of those portfolios. A further discussion of this case and its implication on major decisions and timing can be seen in Chapter 9.



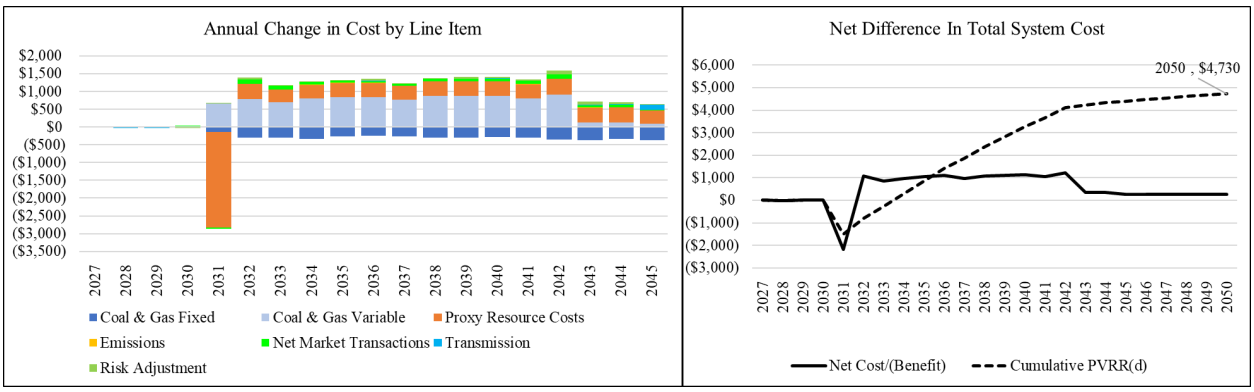


All Coal Retire

The All Coal Retire portfolio replaces 3,364 MW of coal resource capacity with 2,650 MW of new gas combined cycle and new gas peaking resource capacity, with 2,452 MW of peaking coming online in 2032, as well as 54 MW of wind, 12 MW of solar, 18 MW of long duration battery and 251 MW of new hydrogen storage peaking resource. Gas is accelerated into 2032 to replace coal, and 151 MW of 4-hour storage is removed from the portfolio. A comparison of the All Coal Retire portfolio and the Preferred Portfolio resource selections is below.

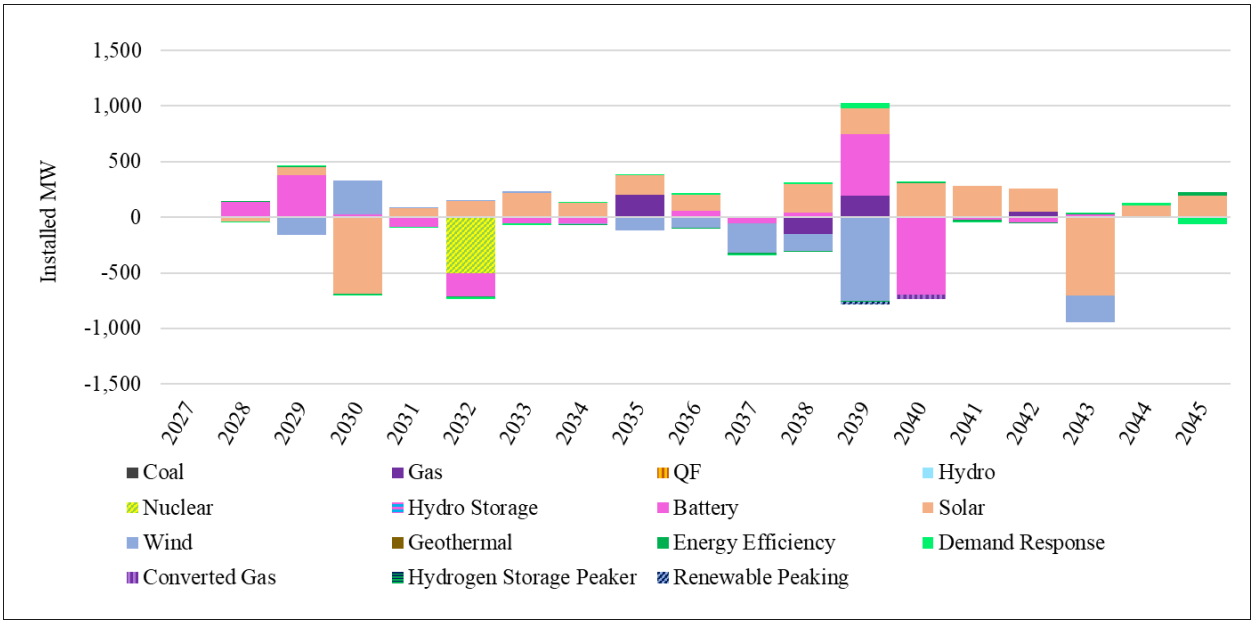


The All Coal Retire portfolio represents a risk adjusted, with end effects cost of $4.73 billion to the system. There is a large reduction in fixed costs due to retiring the coal fleet. A $3.5 billion reduction in coal fixed costs is partially offset by a $1.57 billion increase in gas fixed costs, additional transmission costs and higher proxy costs. As seen in the graph on the left below, there is a large, one-time decrease in costs in 2031 due to removing the CCS unit. This also leads to a large increase in coal and gas variable costs as the 45Q tax credit is removed. The capacity from coal plants must be replaced to maintain system reliability and this results in an increase in proxy capital costs, as well as a large increase in gas fuel costs. The increase in gas fuel, a net increase in market purchases and the increase in proxy capital represent the majority of the cost increases in this portfolio as shown below. A further discussion of this case and it's implication on major decisions and timing can be seen in Chapter 9.



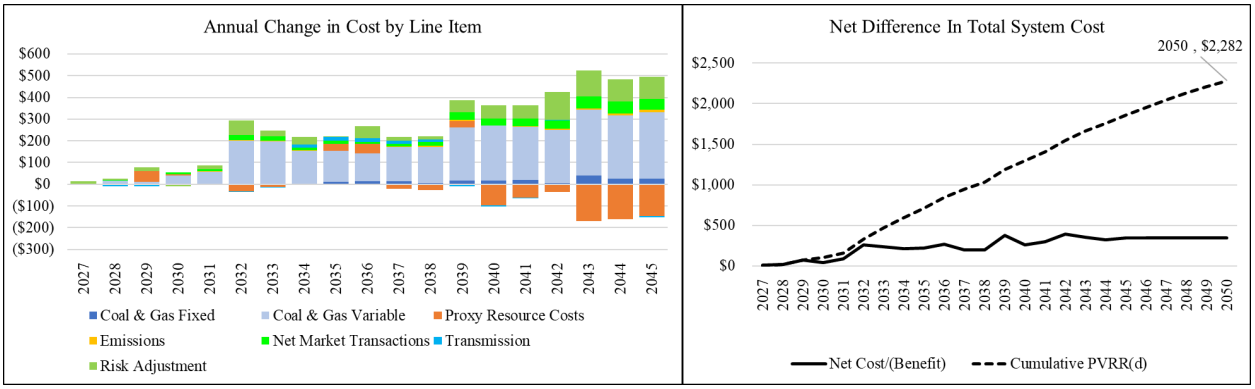
No Future Technology

The No Future Technology portfolio replaces all potentially speculative technology types, including Kemmerer Unit 1 and long duration battery storage. These resources are mainly replaced by shorter duration 4-hour battery storage. While it is difficult to see in the graph below due to all battery storage resources being categorized together, 523 MW of long duration battery storage are replaced by 513 MW of shorter duration 4-hour battery storage. There is also comparatively more utility solar and less utility wind selected, and 20 MW of renewable peaking is removed. This variant also selects 310 additional MW of gas resources. Since Kemmerer Unit 1 was only given energy value in the model and no firm capacity value, capacity resources are not selected to replace any lost Kemmerer Unit 1 capacity, only energy. A comparison of the No Future Technology portfolio and the Preferred Portfolio resource selections is below.



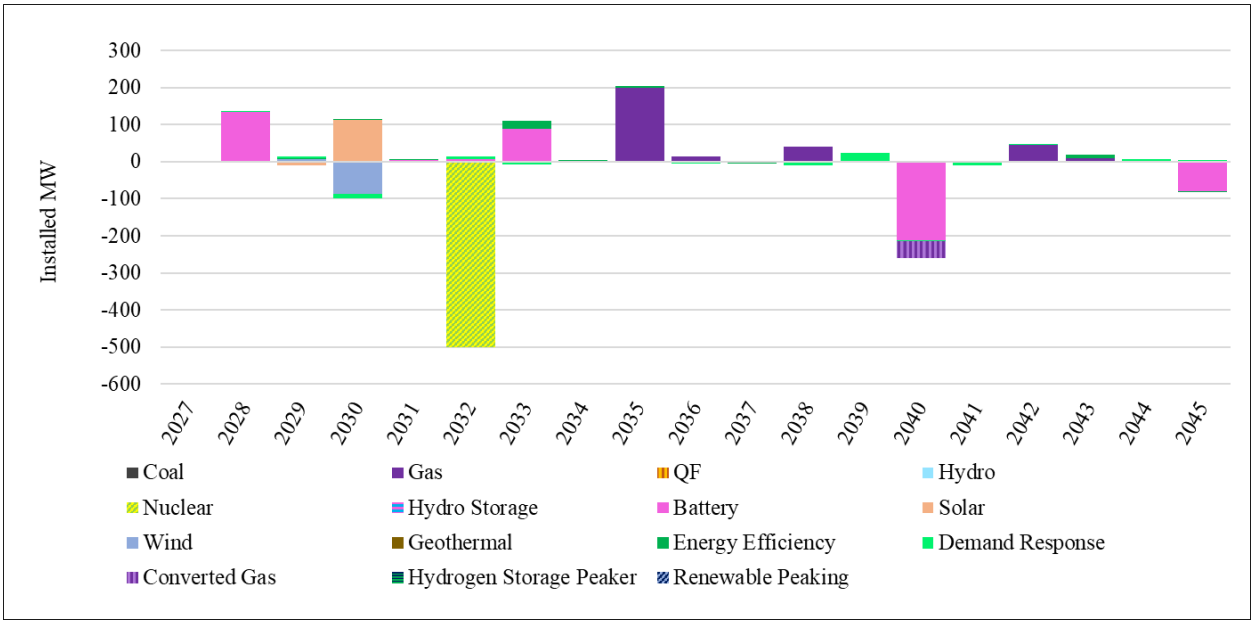
The No Future Technology case represents a risk adjusted, with end effects cost of $2.28 billion to the system. This cost increase is driven by large increases to coal and gas fuel and variable operating costs. There is also an increase in market purchases in this portfolio. The No Future Technology case does have a decrease in proxy capital costs due to the lower build cost of 4-hour

battery versus 100-hour storage. A modest reduction in fixed and capital expenses is overtaken by significant variable cost increases in this portfolio. A further discussion of this case and it's implication on major decisions and timing can be seen in Chapter 9.



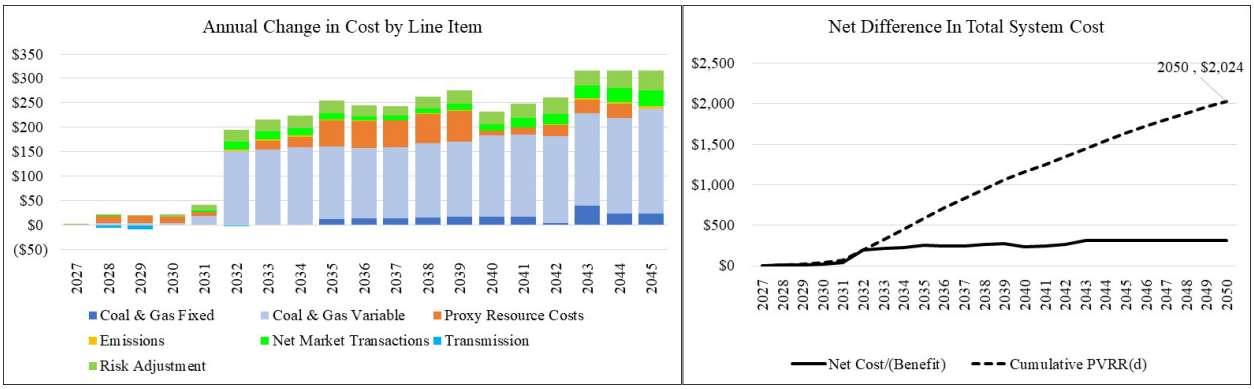
No Kemmerer Unit 1

The No Kemmerer Unit 1 case reviews what selections the model would make to replace the energy provided by Kemmerer Unit 1. Kemmerer Unit 1 does not provide capacity due to its shared interconnection at the Naughton plant, so there is no requirement to change capacity resources. That said, long duration storage shifts from the end of the horizon into 2031-2033. The model also selects an incremental 310 MW of new gas and also moves megawatts from the 2040s into 2038. There is also an incremental increase of 39 MW of DSM, and the model shifts a small amount of renewable selections from wind to solar.



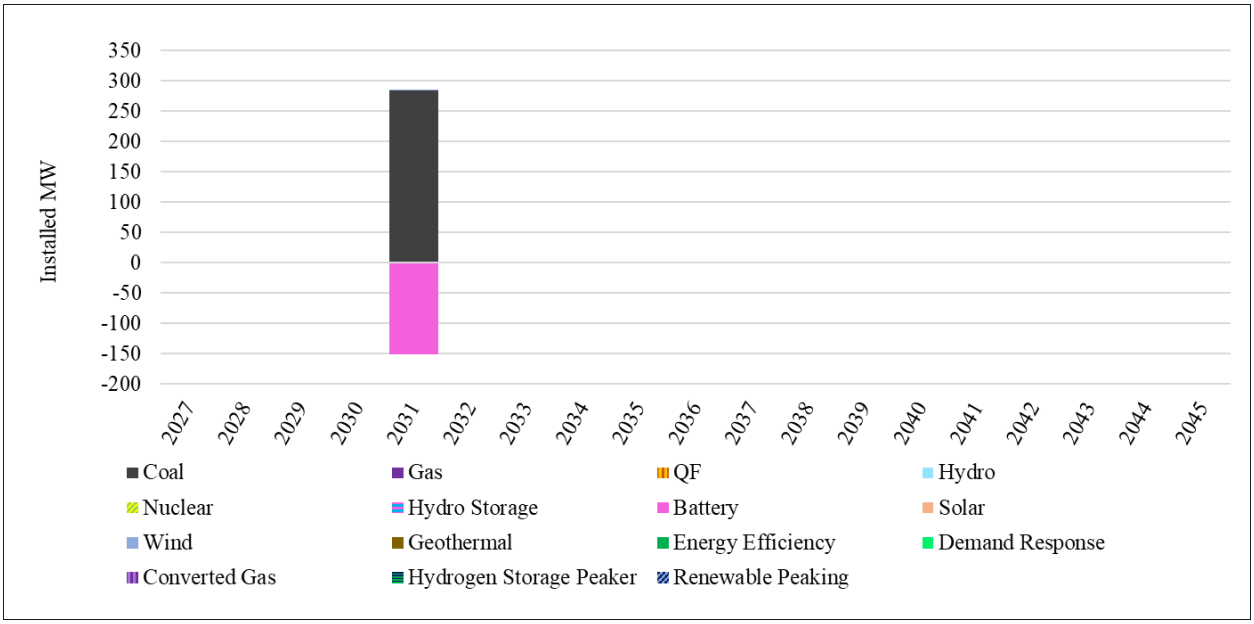
The No Natrium portfolio represents a risk adjusted, with end effects cost of $2 billion to the system. This is primarily driven by much higher coal and gas fuel and variable costs, generally due to the lack of energy being delivered to the system from the Naughton area. There is a small increase in market reliance, and also an increase in proxy capital costs as the model selects

additional resources to replace the energy from the Natrium project. Kemmerer Unit 1 is modeled without costs in PLEXOS, and a further description of the potential risks and costs associated with this unit is contained in Chapter 9 - Alternative Path Analysis.



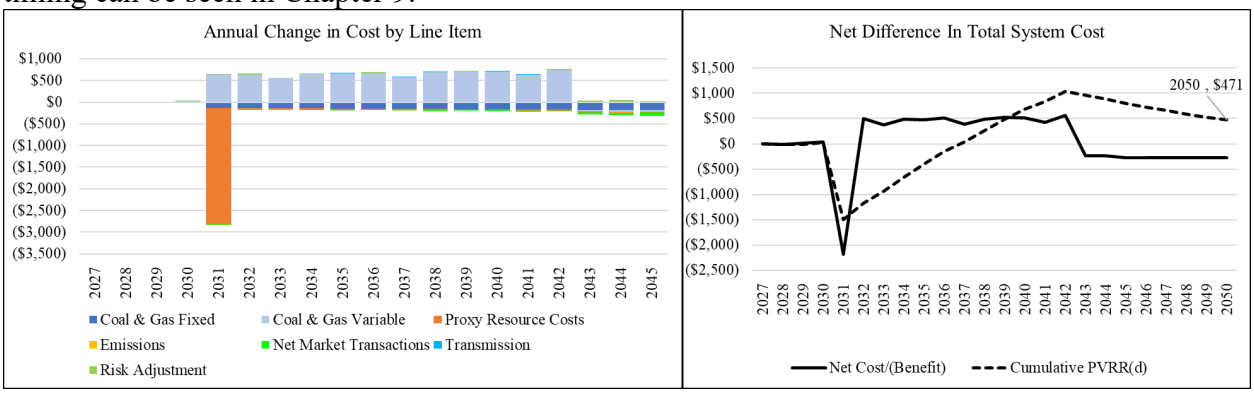
No CCS

The No CCS case does not allow the model to select CCS at any location. The Bridger CCS units are replaced with Jim Bridger units 3 and 4 as coal. As coal, Bridger 3 and 4 contribute more total capacity to resource adequacy than they do as CCS. In the case with CCS, this difference is made up with battery, however when CCS is not selected, this battery capacity is no longer needed for the system.



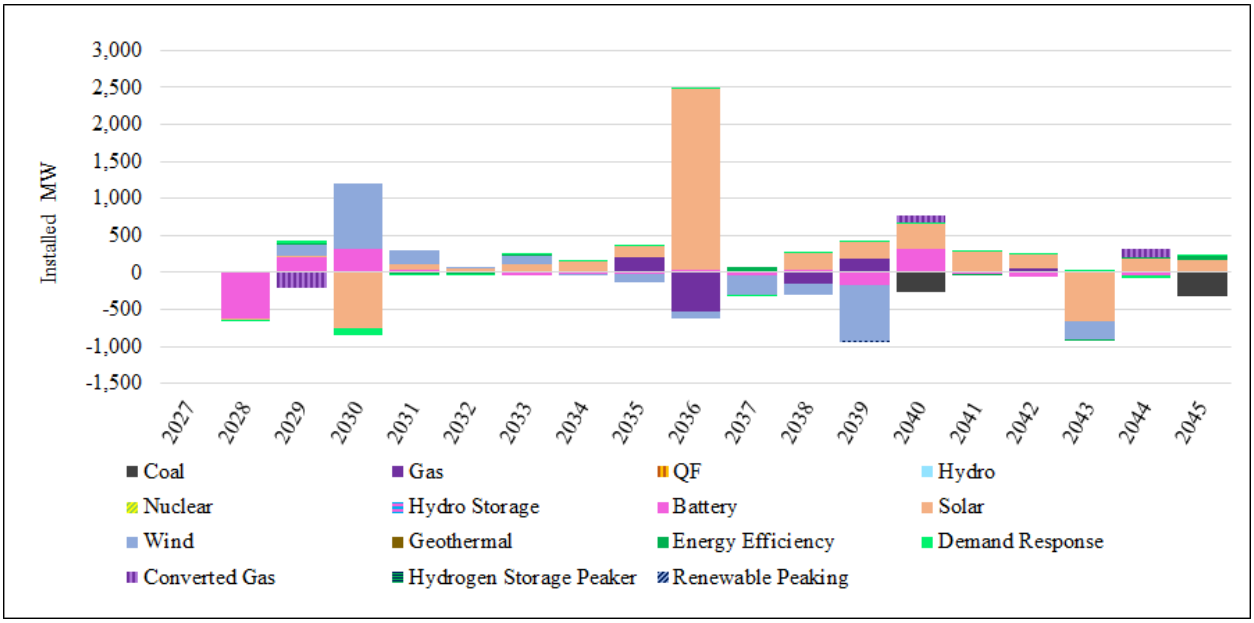
The No CCS case represents a risk adjusted, with end effects cost of $471 million to the system. Lower fuels, coal fixed and capital costs in the dispatch of the portfolio without CCS are offset by the significant revenue generated by the 45Q tax credit in the portfolio with the CCS. The remaining costs remain relatively stable, with a minimal impact on market transactions. Notably, in the case without CCS, PacifiCorp would forgo a significant capital investment to install the CCS on Jim Bridger 3 and 4 as seen in the left hand graphic. Forgoing this capital cost, however, leads to increases in annual costs, with the cumulative PVRR(d) crossing past 0 in 2037 as seen in the

graphic on the right. A further discussion of this case and its implication on major decisions and timing can be seen in Chapter 9.



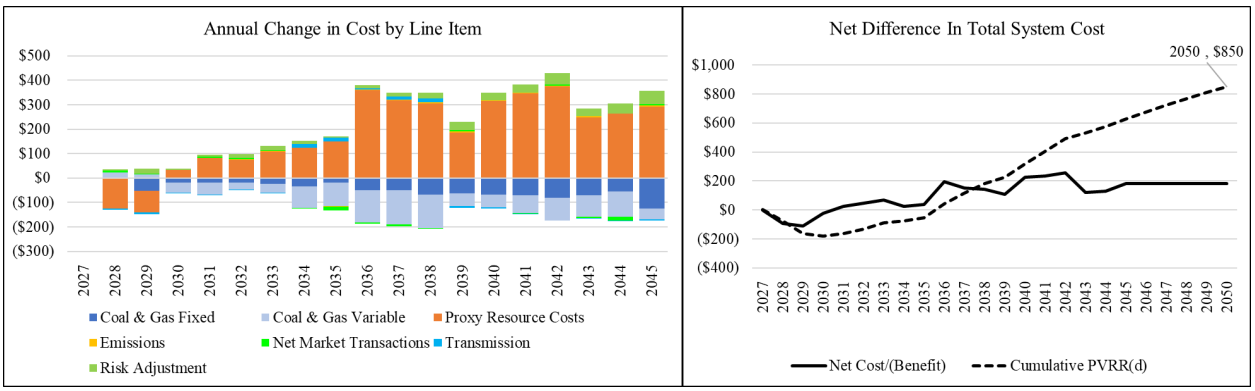
High Thermal Fuels and High CO_2 Price

The high fuels, high CO_2 price policy portfolio explores portfolio selections in a world where thermals prices are high and there is a cost penalty across the system on carbon dioxide emissions. In this portfolio, the model selects a significant amount of new proxy solar resources over the 20-year horizon. The model increases solar selections by 3,123 megawatts over the preferred portfolio, with a substantial portion being built at coal sites as surplus interconnection. There is a reduction in wind selections over time, with a shift moving selected wind earlier in the horizon. This portfolio also swaps 4-hour battery for long duration storage. There is a net decrease in new gas selections, with gas choices moving from peaking resources to combined cycle plants. Additionally, the high cost case retires Wyodak in 2040 and Dave Johnston 4 in 2045.



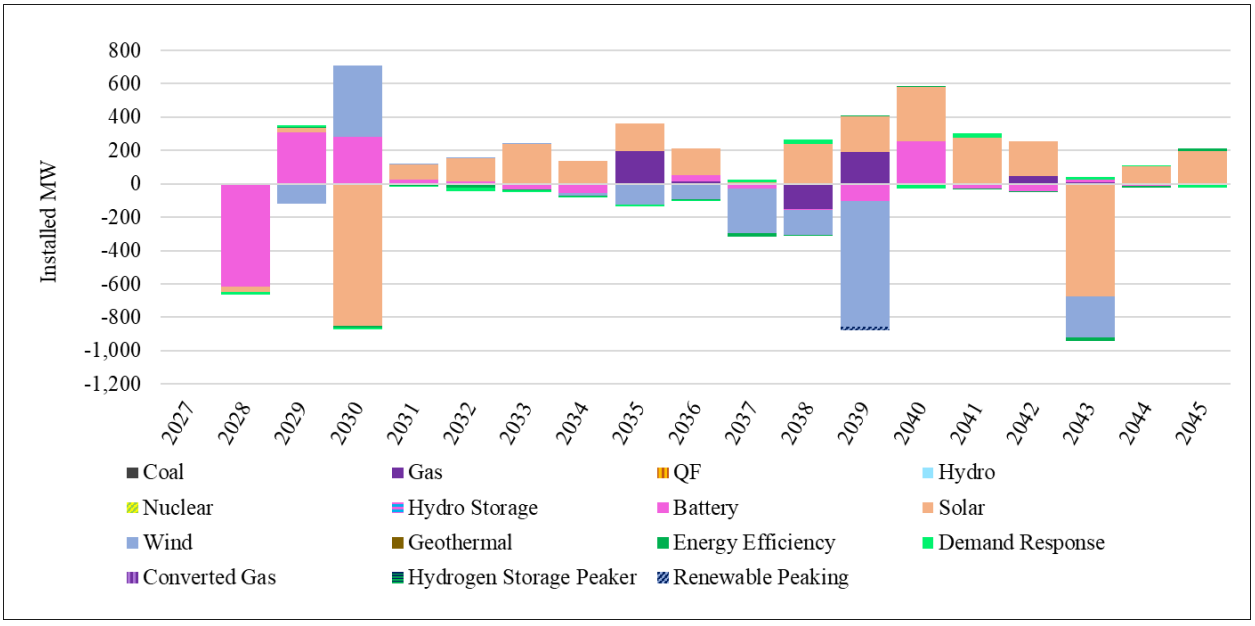
The HH case represents a risk adjusted, with end effects cost of $850 million to the system. Reductions in coal and gas fixed and variable costs are offset by much higher proxy resource costs. The significant investments required when coal and gas fuel prices are high leads to large capital and fixed costs for replacement resources. If high prices are not realized, the smaller savings from

gas and coal operations no longer offset the high cost of proxy investments. A further discussion of this case and its implication on major decisions and timing can be seen in Chapter 9.



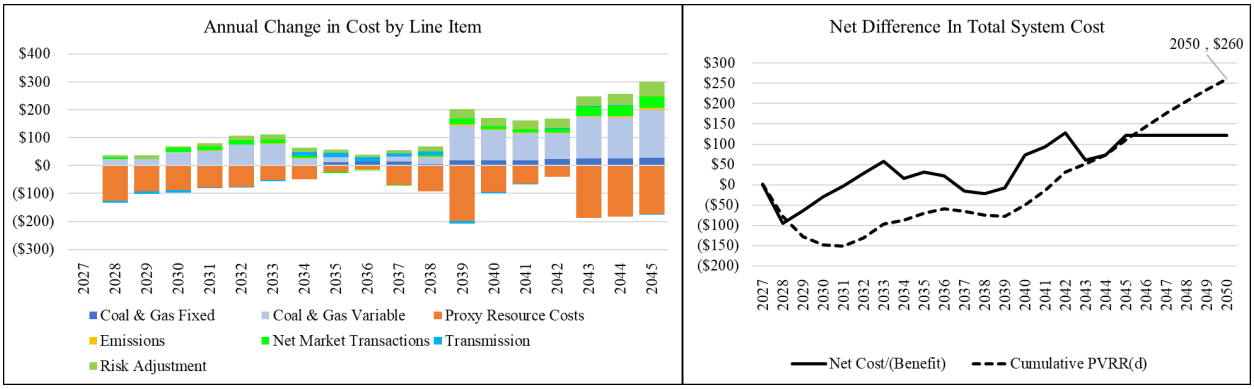
Low Gas and No CO_2 Price

The low gas and no CO_2 price portfolio looks at a future where gas prices are low and there is no cost to carbon dioxide emissions. In this future, the model selects more gas than in the preferred portfolio, and shifts gas selections earlier with a net increase of 311 MW, and a net shift of 300 of those megawatts moving from 2043 earlier, 212 MW by 2036. The LN portfolio also selects less DSM, swaps short duration storage for long duration storage and exchanges wind for solar renewable resources, with a net decrease in renewable energy resources of 367 MW. Most of these changes occur throughout the horizon, however the net increase in 100-hour storage takes place in 2030.



The LN case represents a risk adjusted, with end effects cost of $260 million to the system. On a deterministic basis, the LN portfolio dispatched under the MN price curve presents a $64 million benefit, primarily due to lower proxy resource build and fixed costs. The reduction in resources leads to greater risk however, and the LN risk adjustment is $174 million larger than the MN

adjustment, leading to a pre-end effects risk adjusted cost of $110 million compared to the MN portfolio. The LN portfolio builds more gas than the MN, and as a result of these build selections, combined with lower renewable energy generation leads to higher gas and coal variable costs and higher market reliance. This higher variable cost structure leads to greater risk and the larger risk adjustment in the LN case as seen in the graph below. In addition to cost risk in the LN case the volatility of this portfolio with fewer renewable generating resources introduces a state compliance risk. A further discussion of this case and its implication on major decisions and timing can be seen in Chapter 9.



CHAPTER 8 – SENSITIVITIES

Introduction

In contrast to the eligible variant studies described in Chapter 7, sensitivity outcomes are not considered eligible for preferred portfolio selection. This is because the assumptions introduced in sensitivity studies are not consistent with expected future conditions, regulatory requirements or operational realities. Some sensitivities provide a direct counterfactual analysis that can be used to measure magnitudes of difference regarding cost or risk. Sensitivities can also illustrate the degree to which a particular solution is not cost- or risk-effective. Sensitivities are also a key component in the alternative path analysis presented in Chapter 9.

In the 2025 IRP Update, partly in response to stakeholder interest[1], the analysis of each sensitivity has been expanded here beyond that provided in past IRP filings. Each sensitivity is examined for its key features and relevant metrics, including total system cost. Also, each analysis includes a determination of whether or not the sensitivity contributed specific guidance to the selection or content of the preferred portfolio. Finally, a qualitative robustness assessment is included to illustrate how each of the eligible variant portfolios aligns with the alternative reality suggested by each sensitivity portfolio.

PacifiCorp analyzed several sensitivities of interest in the 2025 IRP Update, shown in Table 8.1.

Table 8.1 – Sensitivities

Sensitivity Study Name	Description
B2H Redirects	Assumes BPA grants PacifiCorp redirects related to B2H by 1/1/2028
Federal Tax Credits (Counterfactual)	Assumes resumption of IRA/IIJA tax credits starting in 2030
No HB 2021 (Counterfactual)	Removes compliance with HB 2021 to provide a basis for estimating the incremental cost of compliance with HB 2021
Dave Johnston Coal-Fired	Allows Dave Johnston units 1-3 to continue running on coal after year end 2027 (unit 3) and 2028 (units 1 and 2)

Sensitivity Analysis

Each of the four sensitivities for the 2025 IRP Update is discussed below, noting that the HB 2021 counterfactual is primarily analyzed in Appendix D – Oregon Clean Energy Update.

Boardman to Hemingway (B2H) Redirects Sensitivity Analysis

Figure 8.1 compares the resource selections between the B2H redirects sensitivity and the preferred portfolio. While the graph reveals a preference for solar compared to wind in the B2H

[1] PacifiCorp anticipates providing See Appendix G, stakeholder feedback form #18 (Utah Clean Energy, et al.)

redirects portfolio, total proxy renewable resource selections are around 250 MW lower in the B2H redirects portfolio compared to the preferred portfolio. There are also around 200 MW less proxy storage resources and 300 MW more proxy gas resources selected in the B2H redirects portfolio compared to the preferred portfolio. The overall decrease in proxy resource selections by around 200 MW in the B2H redirects portfolio is made possible by the availability of BPA redirects which enable resources on the east side of PacifiCorp's system to serve load deeper into the west side of PacifiCorp's system via B2H.

Figure 8.1 -- Incremental Portfolio Selections for B2H Redirects less Preferred Portfolio

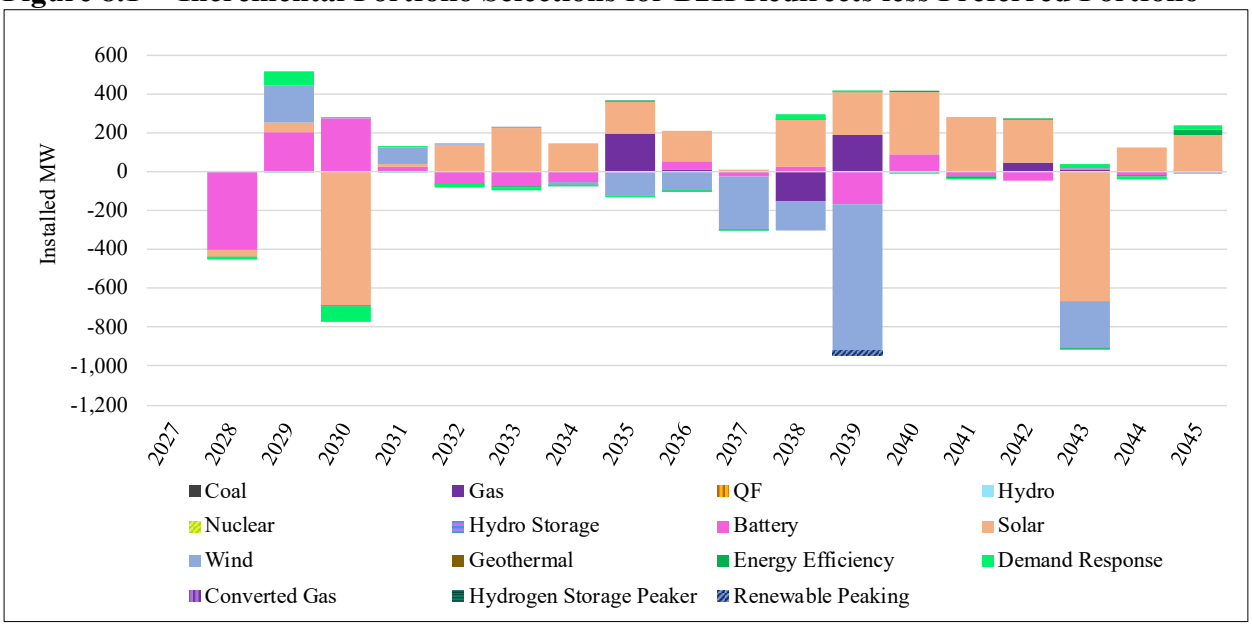
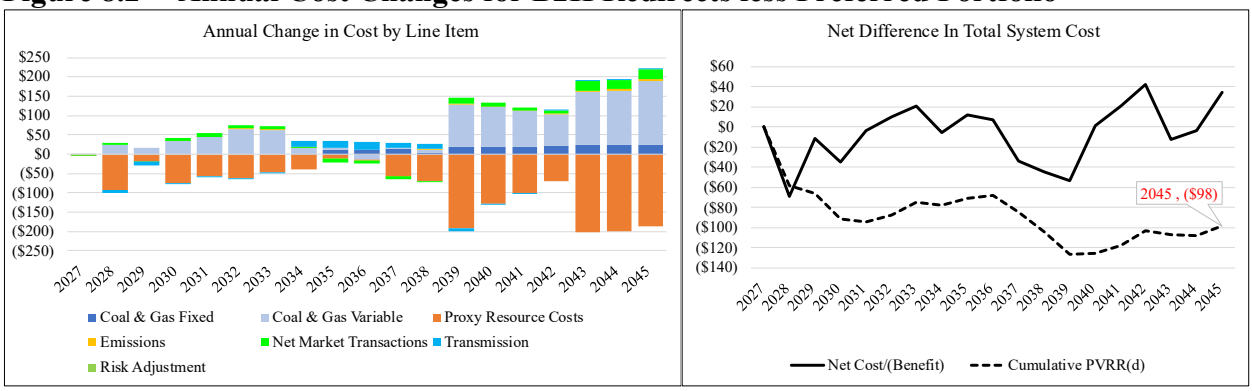


Figure 8.2 compares the annual costs between the B2H redirects sensitivity analysis and the preferred portfolio. Positive numbers indicate that a given cost is higher in the B2H redirects sensitivity while negative numbers indicate a cost savings in the B2H redirects portfolio. Over the twenty-year horizon, the B2H redirects sensitivity lowers system cost by $98 million relative to the preferred portfolio. The ability to have more east-side resources reach west retail load leads to an increase in coal and gas variable costs as these resources dispatch more frequently. This increase in cost is more than offset by the reduction in proxy resource costs in the B2H redirects portfolio relative to the preferred portfolio.

Figure 8.2 -- Annual Cost Changes for B2H Redirects less Preferred Portfolio



In alignment with stakeholder feedback, PacifiCorp offers this B2H sensitivity analysis, which assumes that redirect rights are available as an option to serve load deeper in the west side of the system.[2] This study is presented as a sensitivity, and not as a baseline assumption nor a variant because it is unknown when or to what extent redirects will be achieved, and this is largely outside of PacifiCorp's control.[3,4] The ability of B2H to serve existing retail load in the western balancing area authority is dependent on acquiring transmission re-directs from Bonneville Power Administration[5]. Including these re-directs as a base assumption presents a significant risk of overreach in long-term planning, potentially to the detriment of customers and regulatory compliance. However, as new information becomes available or the situation evolves, this sensitivity may become a baseline assumption. This sensitivity suggests that there is additional value to B2H assuming re-direct rights are acquired at a reasonable cost to customers. The results of this analysis indicate PacifiCorp should continue to pursue these rights and attempt to negotiate favorable terms for customers.

No HB 2021 Counterfactual Analysis

This sensitivity directly serves the purpose of providing a counterfactual to the base assumption of Oregon House Bill 2021. This sensitivity does not change the preferred portfolio but rather informs the assessment of HB 2021 costs and portfolio impacts relevant to compliance, emissions and recovery. As this analysis is so closely aligned with Oregon planning, the bulk of the analysis is presented in Appendix D – Oregon Clean Energy Update. Additional information is provided below regarding the Robustness Assessment.

Federal Tax Credits Counterfactual Analysis

This sensitivity serves as a counterfactual to the preferred portfolio and assumes that IRA/IIJA federal tax credits resume in 2030. Prior to 2030, federal tax policy remains aligned with the One Big Beautiful Bill Act. The purpose of this sensitivity is to show how changes in federal tax policy beyond the near-term procurement window (2030 and beyond) may impact proxy resource selections and other decisions made by the company. Due to the recent changes to federal tax policy and uncertainty surrounding future policy, PacifiCorp believes it is reasonable to evaluate a future where IRA/IIJA tax credits are re-established. This study is presented as a sensitivity, and not as a baseline assumption nor a variant because it is unknown what federal tax policy will be in the future.

Figure 8.3 compares the resource selections between the 2030 federal tax credit sensitivity analysis and the preferred portfolio. The major difference in resources selections between these portfolios comes in energy resources, with additional wind selected in 2031, and significant solar selections in 2035 and 2036. Incrementally, 358 additional megawatts of wind and 3,540 additional megawatts of solar is selected in this sensitivity. The extra energy and capacity from these resources displaces just more than 1,100 megawatts of new gas resources. Because investment tax credits continue to be available on storage resources, there is little difference in total battery storage

[2] See Appendix G, stakeholder feedback form #2 (Sierra Club, et al.)
[3] See Appendix G, stakeholder feedback form #4 (Sierra Club, et al.)
[4] See Appendix G, stakeholder feedback form #9 (Sierra Club, et al.)
[5] Recently added load that is geographically accessible is an exception and can be served without redirects.

selections between the Preferred and Tax Credit portfolios. However, the additional energy from renewables during high solar and wind energy periods leads to a swap between 4-hour storage and 100-hour storage.

Figure 8.3 -- Incremental Portfolio Selections for Federal Tax Credits less Preferred Portfolio

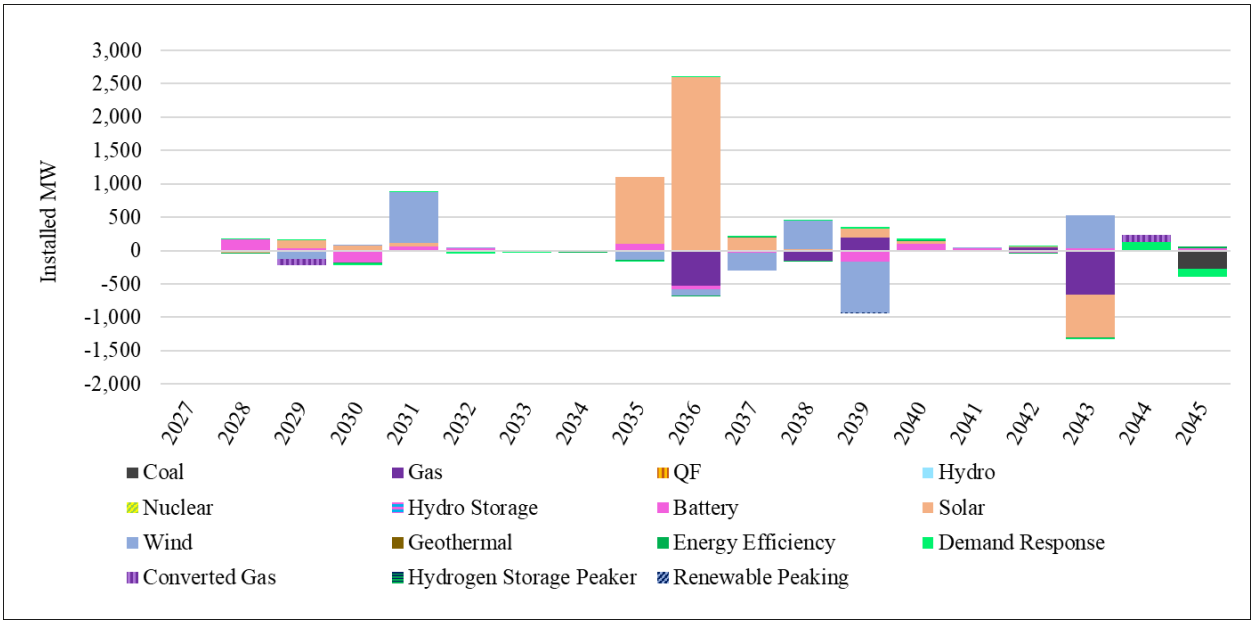
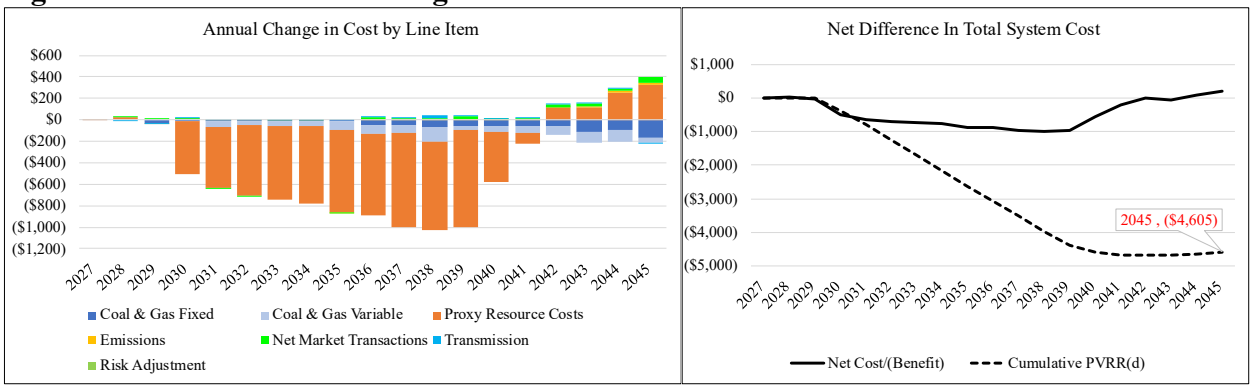


Figure 8.4 compares the annual cost changes between the 2030 federal tax credit counterfactual analysis and the preferred portfolio. Positive numbers indicate that a given cost is higher in the federal tax credit counterfactual, while negative numbers indicate a cost savings in the federal tax credit counterfactual. Over the twenty-year horizon, the federal tax credit counterfactual lowers system cost by $4,605 million ($4.605 billion) relative to the preferred portfolio. This cost savings is tied to the significant reduction in proxy resource costs for new renewable resources from 2030 onward as a result of the re-introduction of IRA/IIJA federal tax credits in 2030. From 2040 onward, proxy resource cost savings begin to lower as the 10-year tax credit lives of new renewable resources built in 2030 or later begin to expire. There are also significant cost savings in the federal tax credit counterfactual with regard to coal and gas fixed and variable costs. This is due to the large amount of new renewable resources selected in the counterfactual which displace some of the new gas selected in the preferred portfolio and reduces the generation of new and existing coal and gas resources compared to the preferred portfolio.

Figure 8.4 -- Annual Cost Changes for Federal Tax Credits less Preferred Portfolio



This sensitivity does not change the preferred portfolio but rather indicates the potential value to customers and portfolio development were another reversal of federal policy to take place in the next many years.

Dave Johnston Coal-Fired Sensitivity Analysis

Figure 8.5 compares the resource selections between the Dave Johnston sensitivity analysis and the preferred portfolio. The graph reports an increase in coal capacity and a reduction in coal-to-gas conversion capacity due to the continued coal-fired operation of Dave Johnston units 1, 2, and 3. In later years, there is also a reduction in proxy gas resources that are no longer needed given the continued operation of Dave Johnston unit 3.

Figure 8.5 -- Incremental Portfolio Selections for Dave Johnston Coal less Preferred Portfolio

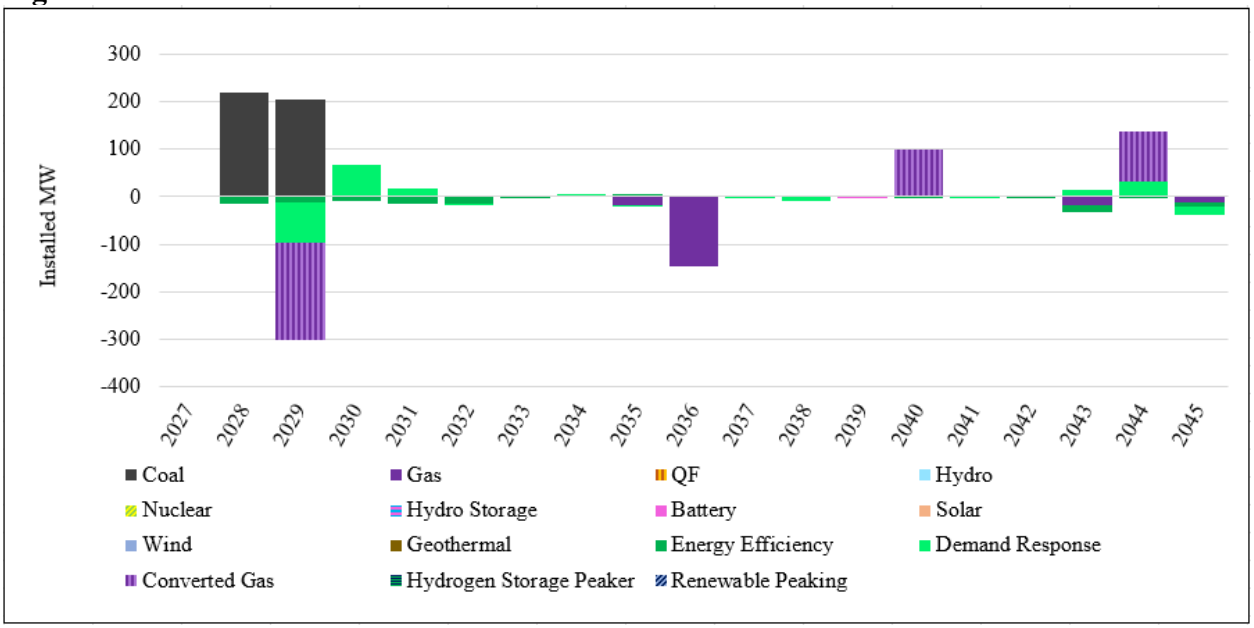
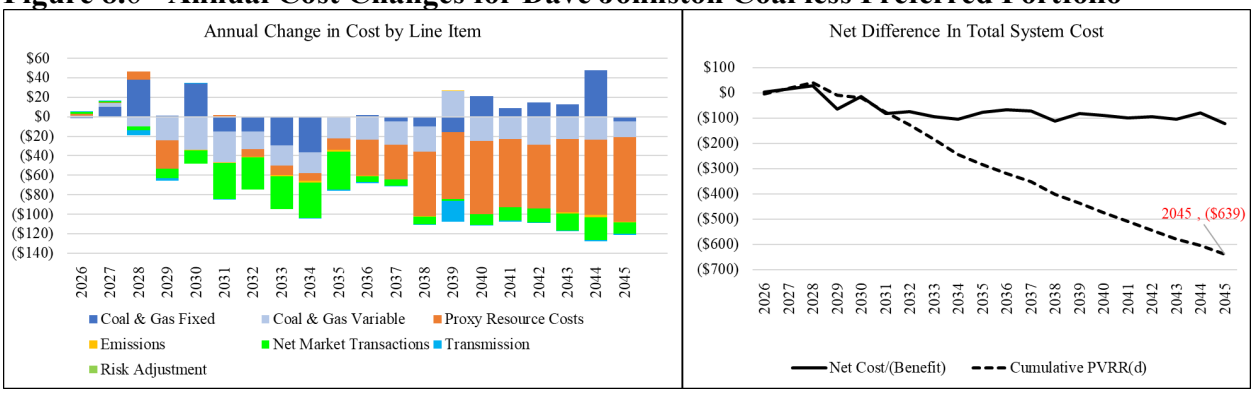


Figure 8.6 compares total system cost between the preferred portfolio and the Dave Johnston coal-fired sensitivity. Positive numbers indicate that a given cost is higher in the Dave Johnston sensitivity, while negative numbers indicate a cost savings in the Dave Johnston sensitivity. Over the twenty-year horizon, the Dave Johnston sensitivity lowers system cost by $639 million relative

to the preferred portfolio. This cost savings is attributable to reductions in market transaction costs, savings in gas fuel costs, and deferred proxy resource costs.

Figure 8.6 - Annual Cost Changes for Dave Johnston Coal less Preferred Portfolio



The outcome of this sensitivity does not change the preferred portfolio but rather indicates the potential value of finding a regulatory path to allow the Dave Johnston plant to continue coal-fired operations through the current planning horizon. Dave Johnston Unit 3 has a December 31, 2027, shutdown requirement as part of a Federal Implementation Plan for Wyoming's Regional Haze first planning period. Dave Johnston Units 1 and 2 have a 'notice of planned participation' under the Clean Water Act Steam Power Effluent Limitation Guidelines (ELG) that require the units to cease coal-fired operation by December 31, 2028. PacifiCorp has submitted a petition for reconsideration to EPA requesting that they remove the Unit 3 shutdown requirement and is evaluating options that would allow Dave Johnston Units 1 and 2 to continue operating on coal while maintaining compliance with ELGs. This sensitivity analysis is further discussed in Chapter 9 regarding the alternative path analysis.

Robustness Assessment

In addition to the case-by-case sensitivity analysis provided above, the sensitivity robustness assessment qualitatively examines the portfolio similarities and differences between each eligible variant presented in Chapter 7, and each sensitivity portfolio in this chapter.

As opposed to the robustness analysis included in Chapter 7 in support of the preferred portfolio, this sensitivity robustness analysis does not directly consider PVRR cost. This is because sensitivities are not consistent with expected future conditions, regulatory requirements or operational realities, and cannot then be measured against eligible variants on the basis of cost. For example, the HB 2021 Counterfactual Analysis "pretends" that HB 2021 does not exist. If this portfolio results in a lower PVRR than the preferred portfolio, this does not make the counterfactual competitive, because the portfolio is built around a future that cannot be assumed to occur.

The basis of the following assessment is therefore focused on portfolios, not costs, and asks the question, "How do the eligible portfolios compare to each sensitivity portfolio?" The supposition is that the more similar an eligible portfolio is to a sensitivity portfolio, the better aligned the variant is with the hypothetical reality of the sensitivity. This comparison is made not as an explicit

measure, but rather as a prompt for discussion and to suggest potential analysis for future reports and filings.

Figure 8.7 through 8.9 report the volumes of all studies portfolios in three broad categories:

- Net Dispatchable Capacity Additions:
  Includes additions, retrofits, retirements or expirations in any technology type other than wind and solar, such as gas, coal, nuclear, geothermal, renewable peaking, hydro, storage, demand response.

- Net Non-Dispatchable Resource Capacity Additions:
  Consists of additions, retirements or expirations of wind and solar resources.

- Cumulative Energy Efficiency Savings:
  Defined as the additive amount of energy efficiency savings that are not captured in the load forecast used in the IRP.

Figure 8.7 - Net Dispatchable Capacity Additions by 2045 (GW)

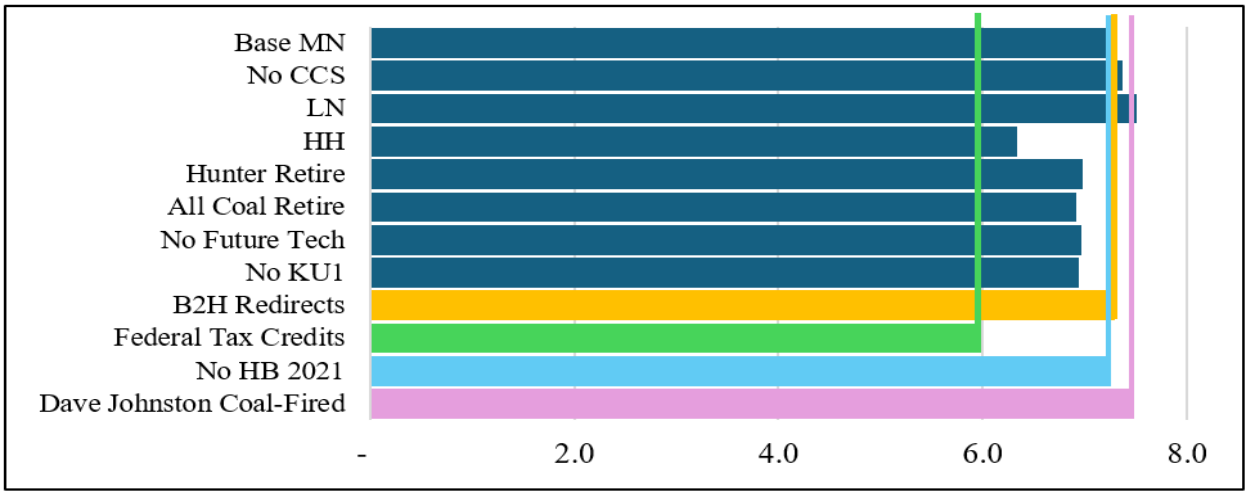


Figure 8.8 - Net Non-Dispatchable Resource Capacity Additions by 2045 (GW)

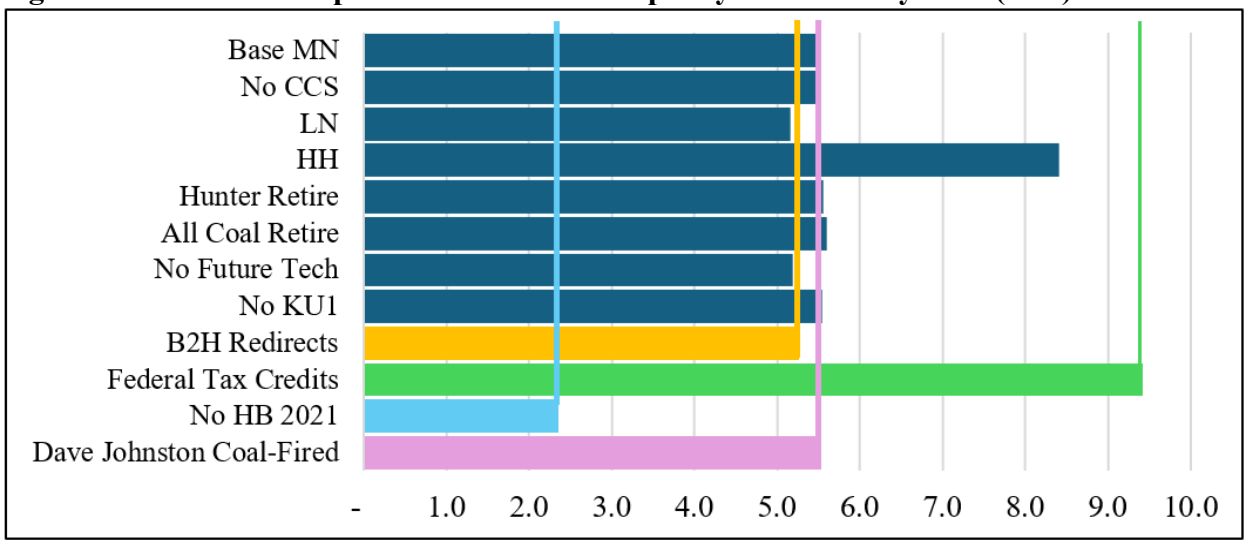
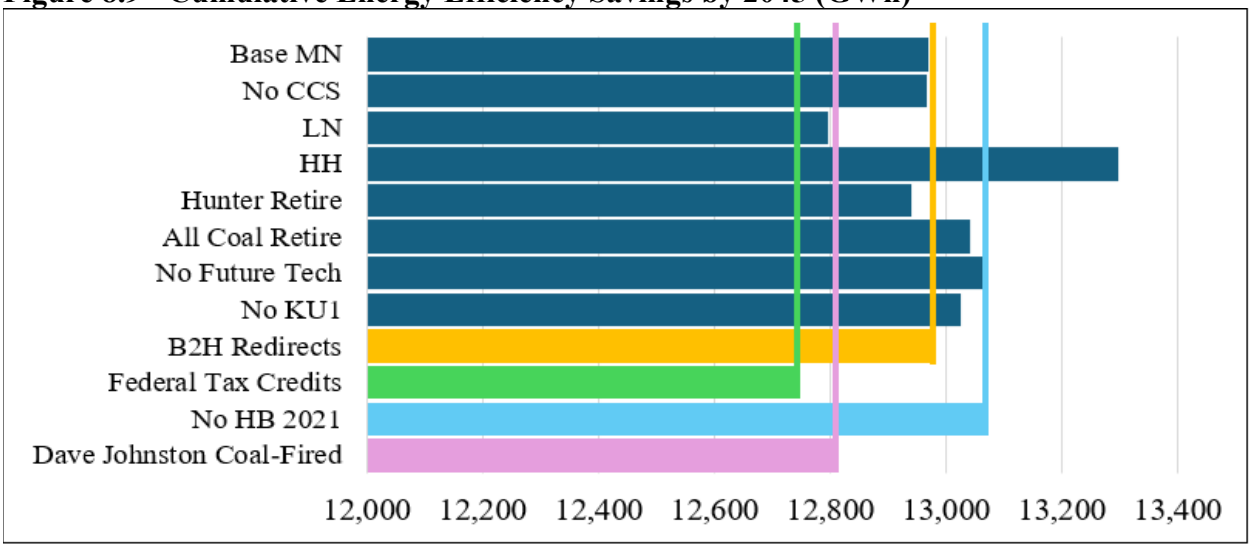


Figure 8.9 - Cumulative Energy Efficiency Savings by 2045 (GWh)



B2H Redirects

Many of the eligible variants broadly align with the B2H Redirects sensitivity. The two studies with the most significant divergence are the price-policy variants LN and HH, where the LN portfolio reports significantly less cumulative energy savings (188 GWh), and the HH portfolio reports less installed dispatchable capacity (954 MW), dramatically higher renewable resources (3,140 MW) and significantly higher energy efficiency savings (148 GWh).

The Base MN (preferred portfolio) is very similar in each category with the exception of somewhat higher renewable resource capacity (260 MW).

This comparison of resource selections shows that if PacifiCorp receives BPA redirect rights, there would be only modest changes to the broad composition of the preferred portfolio. The rights may slightly reduce the need for new renewable energy resources by reducing curtailments and allowing more existing resources located on the east side of PacifiCorp's system to serve west side load.

Federal Tax Credits

The eligible variants generally select paths that diverge from the Federal Tax Credits sensitivity. All variant portfolios include more dispatchable capacity than the federal tax credits sensitivity. The relative increase ranges from 358 MW (HH portfolio) to 1,531 MW (LN portfolio).

The HH portfolio shows a gigawatt less renewable resource capacity. All of the other variants lower renewable resource capacity by more than three gigawatts relative to the Federal Tax Credits sensitivity.

The LN portfolio is closest to the volume of energy efficiency included in the Federal Tax Credits sensitivity. The other variants all include over 400 GWh of incremental energy efficiency.

None of the variants is particularly similar to the Federal Tax Credits sensitivity over the entire model horizon (2026-2045). If federal tax credits for new wind and solar resources actually resume in 2030 (or afterwards), the best path forward from that point onwards will change. However, the near-term selections in the preferred portfolio would not substantially change even if it was known now that federal tax credits would resume in 2030. PacifiCorp's near-term procurement of wind and solar is driven by Oregon and Washington regulation requiring new resources that are online by the end of 2030. No new gas resources are included in the preferred portfolio until 2035. In the event that federal tax credits resume, PacifiCorp would have sufficient time to assess its procurement actions in future IRPs.

No HB 2021 Counterfactual

The eligible variants generally select paths that diverge from the No HB 2021 counterfactual. The variants select comparable quantities of dispatchable capacity, with the HH portfolio (a 917 MW reduction) showing the most divergence. All of the variants select at least 2,500 MW of incremental non-dispatchable resource capacity. The No Future Technology and All Coal Retire

portfolios select similar amounts of energy efficiency. The LN portfolio (279 GWh reduction) is furthest away from the No HB 2021 counterfactual.

All of the variants differ significantly from the No HB 2021 counterfactual in non-dispatchable resource capacity. This is because all of the variants assume that HB 2021 is in effect and requires significant investments in incremental wind and solar resources. The No HB 2021 counterfactual is useful primarily as the basis for calculating incremental costs attributable to HB 2021, and PacifiCorp expects to comply with HB 2021.

Dave Johnston Counterfactual

Many of the eligible variants broadly align with the Dave Johnston counterfactual. The HH portfolio shows the most substantial divergence. HH includes less dispatchable capacity (1.1 GW), more non-dispatchable resource capacity (2.8 GW), and more energy efficiency (481 GWh).

Many variants include more energy efficiency than the Dave Johnston counterfactual, including Base MN (153 GWh). The LN portfolio is closest to the energy efficiency selections in the Dave Johnston counterfactual, with a relative reduction of 20 GWh.

The preferred portfolio (Base MN) is broadly similar to the Dave Johnston counterfactual in its dispatchable capacity and non-dispatchable resource capacity. This indicates that maintaining Dave Johnston units 1, 2, and 3 on coal-fired operation would not substantially change the broad composition of the preferred portfolio. Other variant portfolios, with the exception of the HH portfolio, are also broadly similar to the Dave Johnston counterfactual.

CHAPTER 9 – ALTERNATIVE PATH ANALYSIS

Introduction

This chapter presents a discussion of future changes and considerations that could lead to real-world resource procurement that differs from the 2025 Integrated Resource Plan (IRP) Update preferred portfolio.

The selection of the updated preferred portfolio is driven by inputs and assumptions that are locked down well in advance of filing. Inputs and assumptions can change continuously or abruptly, and as noted in Chapter 3, federal and state policies impacting resource decisions can also change dramatically. While the preferred portfolio is determined to be least-cost/least-risk under a range of assessed conditions, this determination will evolve with future conditions impacting future reporting.

PacifiCorp's ultimate decisions to procure long-term resources are based on the available resource alternatives and the best available inputs and assumptions at the time the decision is made, inclusive of any important changes since the most recent IRP or IRP Update was prepared.

This chapter addresses alternative path analysis in three ways:

1. **Key Decisions:** An examination of key decisions implicit in portfolio development. For each key decision, the most relevant studies (variants and sensitivities) are initially identified but not immediately discussed. The portfolio-specific analysis follows in the next section.
2. **Alternative Path Case Review:** Each study is evaluated in an alternative path case review, highlighting relevant key decisions.
3. **Portfolio Overview:** A traditional portfolio overview is presented in table form, highlighting notable quantitative shifts in resource selections relative to the preferred portfolio.

Key Decisions

The following key decision points are discussed in this chapter.

- Wind and solar
- Future technology
- Kemmerer Unit 1
- Boardman to Hemingway (B2H) transmission redirects
- Carbon capture and sequestration (CCS)
- Continued coal-fired operation
- New natural gas-fired resource procurement
- Regional resource adequacy
- Short-term market reliance

Wind and Solar Procurement

Highlighted Studies

The most relevant studies in the 2025 IRP Update to wind and solar procurement path analysis are:

- Base MN (preferred portfolio)
- High Gas, High Carbon price
- Federal Tax Credit Counterfactual sensitivity

These studies are explored in the alternative path case analysis section at the end of this chapter. The following discussion explores key factors related to wind and solar procurement.

Key Factors Impacting Wind and Solar Procurement

By the end of 2026, PacifiCorp's current portfolio of owned and contracted resources includes over 5,000 MW of wind and over 3,600 MW of solar. In 2026, the energy from wind resources is expected to exceed 21 percent of PacifiCorp's annual retail load, while energy from solar resources adds nearly nine percent.

In 2030, the resource additions in the 2025 IRP Update preferred portfolio result in a total of over 7,100 MW of wind resources (a 41% increase) and over 6,000 MW of solar resources (a 67 percent increase). Together these wind and solar resources will produce energy equivalent to 43 percent of PacifiCorp's annual retail load in 2030.

Some key considerations for wind and solar procurement include:

- Project availability and construction timelines
- Offer prices (request for proposal (RFP) bids)
- Integration and balancing

PacifiCorp intends to pursue available wind and solar resources where offer prices provide benefits relative to the expected cost savings within its portfolio. Recent changes in tax credits and tariff uncertainty have driven up resource costs, reducing the number of cost-effective opportunities. At the same time, some of those same cost pressures can increase the value of thermal generation, which may reduce the value of a resource portfolio that reflects a greater quantity of wind and solar resources. PacifiCorp also periodically works with individual customers or groups to identify resources to meet voluntary clean energy goals, which can result in contracts for resources that would not otherwise be cost-effective.

Project Availability and Construction Timelines

PacifiCorp's IRP modeling reflects proxy resource assumptions. Proxy resources have generic cost assumptions, do not reflect unique siting restrictions, and allow for rapid buildout with customized hybrid resource configurations. In reality, utility-scale resource additions typically require years of development before a resource would be ready to be offered in an RFP, with multiple additional

years for construction after selection or contract execution. Key preparatory requirements prior to submission of an RFP bid include:

- Generator interconnection requests, studies, and agreements: enabling a resource to be connected to the electric grid within the required timeline of the RFP.
- Landowner negotiations: land ownership or site control allowing for construction of the generation facility including its connection to the electric grid.
- Permitting: a variety of local, state, and federal permits may be required, with uncertain timelines and the potential for delay.
- Major equipment / long-lead requirements: While wind and solar resources are based on modular equipment, they can rely on unique equipment specifications and equipment quantities as well as coordination with suppliers. Highly specialized equipment, such as transformers, may need to be ordered several years in advance.

The significant time, effort, and funding necessary to bring a resource to the RFP bid stage limits the number of projects that are available to contract at any given time. The most public evidence of this is the generator interconnection queue, and the upgrade timelines identified in the studies for each project.[1] In addition to the queue, there are other unresolved requirements that can delay or cancel a project entirely.

Offer Prices

Wind and solar project developers will seek to maximize their return on investment. They are motivated to offer their project at the highest price they believe will be accepted, but they face disparate risks and rewards. A slight increase in price will provide a slight increase in return but will also increase the risk that a project will not be selected. While the increase in return is readily identified, the incremental risk of a project not being selected can't be precisely quantified by a developer, and the costs of delaying construction and/or cancellation of a project due to missed permitting or site control requirements are significant. This acts as something of an upper bound on pricing.

The possible offer prices are also bound at the low end by project costs. This includes not just the cost of solar panels or wind turbine equipment but the financing costs needed to support acquisition of that equipment and project construction. These equipment, construction, and financing costs can be estimated when a bid is made in an RFP but generally cannot be finalized until after a contract is executed. Resource owners can also face risks during construction and over the operational life of a project, for instance, from the discovery of archaeological remains or endangered wildlife at the site. Even after contract execution, if a developer's equipment supply, construction support, or financing falls through, or if major archeological or wildlife issues arise, there is a good chance that it will result in the contract being modified.

A portion of a developer's offer price consideration is based on a utility's perceived demand and willingness to pay. A utility's stated requirements in its IRP and RFP can shape developer expectations in this regard. Price consideration is also based on other perceived supply – the

[1] PacifiCorp's Generation Interconnection Queues can be found at www.oasis.oati.com/ppw/index.html. Select "Generation Interconnection" in the left sidebar.

presence of competing resource options from other developers. This is opaque to developers – the quantity of project opportunities that are ready to move forward would not be known when offers are submitted, and details shared publicly would be limited to shortlisted projects and statistics about total bid submissions.

Integration and Balancing

Wind and solar resources are only able to generate during favorable weather conditions. In some hours, generation will be zero, while in other hours, a wind or solar resource will generate at its maximum output. Over the course of a year, utility-scale wind and solar resources typically have output that averages between one-quarter and one-third of their maximum output, though certain highly favorable wind locations can achieve higher average output levels.

The most common weather conditions for a given wind or solar resource result in output that is either near its maximum or near zero. While a wind or solar resource might generate only one-third of the time, installing triple the wind or solar capacity will not result in output in all hours – it will result in triple the volume during favorable conditions, and still little or no volume under unfavorable conditions. This is because solar resources are dependent on the position of the sun and cannot generate at night, and even a portfolio of geographically dispersed wind resources will have output that ranges from well above to well below average. When wind and solar are a small portion of a utility's resource portfolio, the difference between above average and below average conditions has a small impact on the overall portfolio. As wind and solar become a larger part of a utility's resource portfolio, the rest of the resource portfolio must change dramatically to meet load when wind and solar output is low and to reduce output when wind and solar output is high.

For thermal resources, compensating for changes in wind and solar output means ramping up to maximum output when wind and solar output is low and ramping down to a minimum operating level or cycling offline when wind and solar output is high. PacifiCorp currently has approximately 8,400 MW of coal and natural gas-fired resources that can adjust their output in response to changing demand and supply, but they may require an hour or more to ramp from minimum to maximum output, and even more time (and cost) to cycle offline and back on again in response to changing conditions.

Energy storage resources, such as lithium-ion batteries, provide an even larger response to changing conditions by charging when wind and solar output is high and discharging when wind and solar output is low. PacifiCorp currently has contracted with over 1,000 MW of battery storage. All of these batteries have a duration of four hours, so they cannot sustain charging at their maximum level over the entirety of daylight hours or discharging over the entirety of nighttime hours. While the ability to shift excess wind and solar output is valuable, the cost of battery storage is likely to exceed that direct benefit even with federal investment tax credits. To the extent battery storage is needed to ensure reliability, the value of charging and discharging can make it favorable relative to other alternatives for adding capacity (e.g. a peaking resource, like a simple cycle combustion turbine). Effectively, this means that battery storage added to ensure reliability can result in a smaller increase in system costs relative to other possible alternatives, but not a cost decrease.

In summary, a utility's ability to redispatch thermal resources down to avoid solar and wind curtailment is limited and the amount of energy storage that is necessary and cost-effective to ensure reliability needs are also limited. Wind and solar output may need to be curtailed to maintain the balance of load and resources in some intervals. The ability to curtail wind and solar resources through sophisticated control systems that manage resource output is one of the necessary capabilities of wind and solar resources procured through an RFP. Once curtailment is required, additional wind and solar output in that interval would also need to be curtailed. Even if curtailment is not required, the most expensive thermal resources would be backed down first, leaving successive wind and solar resources to back down lower-cost thermal resources, and resulting in lower cost savings. An IRP or RFP evaluates the portfolio-wide impact of diminishing marginal returns from successive wind and solar resource additions. In an RFP, successive wind and solar resource additions would also reflect less and less favorable pricing, with the caveat that a resource with a higher price may be favorable due to its location, technology, or generation profile.

Future Technology

Highlighted Studies

The most relevant studies in the 2025 IRP Update to future technology procurement path analysis are:

- Base MN (preferred portfolio)
- No Future Technology variant
- No Kemmerer Unit 1 variant

These studies are explored in the alternative path case analysis section at the end of this chapter. The discussion below explores key factors regarding wind and solar procurement.

Key Factors impacting Future Technology Procurement

The supply-side resources available for selection in the 2025 IRP Update include a number of resources that are not widely available commercially. The "No Future Technology" variant assumes no availability for nuclear, hydrogen-fueled combustion turbines with electrolysis and storage, 100-hour iron-air battery storage, or biodiesel peaking resource options. Each of these technologies exist but have complications that may hinder utility-scale deployment. The hydrogen and iron-air technologies also represent the primary energy storage options with more than ten hours of storage duration.

Solar, wind, and lithium-ion battery storage technology have all experienced significant cost declines over the past several decades, with some of those cost declines occurring quite rapidly. It is possible that other technologies will experience significant cost savings, as indicated by the "Advanced Technology" line items in the supply-side resource tables.[2] Cost savings can result from technological advancement as well as from economies of scale in manufacturing. These can

[2] See Appendix C (Supply-Side Resource Details)

go hand in hand, as lower prices are likely to result in greater demand, which can enable further cost reductions.

Cost is not the only consideration with new technologies, as operational performance may also be uncertain. In general, developers of new technologies are incented to maximize the projected capability, but whether those results are achievable and can be maintained over time may not be known until years after a resource is placed into service. Operational performance can also be a concern with established technologies, and a variety of contractual terms can be used to help ensure that PacifiCorp receives the capability that was agreed to or is compensated if shortfalls exceed specified levels. This could be part of a warranty or maintenance agreement with the manufacturer of the technology or could be part of a power purchase agreement for a resource owned by a third-party developer. With new technologies, it may take time to understand how to measure operational performance and how to determine appropriate compensation due to performance that deviates from expectations. PacifiCorp also recognizes that shifting performance risk to developers and manufacturers is likely to come at a cost. This cost can be high when performance is uncertain.

While project-specific uncertainty may be high for new technologies, a portfolio that includes new operational capabilities and a diverse array of technologies can avoid risks that could come from over-reliance on a particular technology type. For example, while four-hour duration lithium-ion battery storage is highly competitive today, it is possible that resource adequacy accreditation for four-hour duration resources will fall more rapidly than PacifiCorp currently projects. This outcome would in part be a result of the successful widespread adoption of four-hour battery storage across the west.

Balancing the costs and benefits of future technology will continue to be complex, and a successful procurement occurs when PacifiCorp can agree to a reasonable balance of costs and risks with a project developer and/or manufacturer. For example, as discussed in the next section, PacifiCorp has contracted with Kemmerer Unit 1, which TerraPower is using to demonstrate its Natrium™ technology. Different technologies and circumstances will warrant different levels of risk. While there is a great deal of uncertainty with new technology, there are benefits in evaluating unique opportunities while revisiting requirements and risk mitigation to fit evolving circumstances and different needs. To that end, PacifiCorp will continue to evaluate new technologies in its IRP modeling and will also evaluate any specific proposals that include new technologies that it receives in RFPs or through bilateral discussions.

Kemmerer Unit 1

Highlighted Studies

The most relevant studies in the 2025 IRP Update to Kemmerer Unit 1 analysis are:

- Base MN (preferred portfolio)
- No Future Technology variant
- No Kemmerer Unit 1 variant

These studies are explored in the alternative path analysis section at the end of the chapter. The below discussion explores key factors regarding wind and solar procurement.

Key Factors impacting Kemmerer Unit 1

In July 2025, PacifiCorp executed a contract with US SFR Owner LLC, a subsidiary of TerraPower, for nuclear energy from the Natrium™ commercial demonstration plant, named Kemmerer Unit 1 (KU1). The KU1 project is a 345-MW sodium-cooled fast reactor being constructed in proximity to PacifiCorp's existing Naughton generation plant and interconnection facilities in Kemmerer, Wyoming. The nuclear reactor will be coupled with a molten salt integrated energy storage system, allowing for flexible operation from 100 to 500 MW for up to 5.5 hours.

The contract for KU1 includes comprehensive risk mitigation strategies addressing the unique challenges of first-of-a-kind nuclear technology, allowing for demonstration of Natrium technology while protecting customers from associated risks. To that end, the KU1 project is proposed to interconnect as a surplus resource, sharing the interconnection capacity of the existing Naughton plant. This eliminates the need for upgrades to accommodate additional resources on the transmission system, which could be expensive or result in delays. Because PacifiCorp intends to keep its Naughton units available to ensure system reliability, it will not be reliant on KU1 output for capacity and reliability needs. Customers are also protected via an innovative pricing structure.

While the contract contemplates that KU1 will achieve commercial operation in fall 2031, PacifiCorp recognizes that first-of-a-kind technologies in general, and nuclear technology in particular, face significant risks of delay. The contract could potentially even be terminated without KU1 ever achieving commercial operation. KU1 could also achieve commercial operation with restricted output and less dispatch flexibility than was anticipated.

While the contract's innovative pricing structure addresses the costs the customers will pay for KU1's generation under any of these conditions, it remains PacifiCorp's obligation to secure a portfolio of resources that balance the costs and risks of the service provided to customers. If KU1 reaches commercial operation as expected, it will provide a cost-effective resource that enhances PacifiCorp's portfolio and contributes to long-term savings. In that case, the potential savings from alternative long-term resource options would be modestly reduced because KU1 would already be fulfilling part of the system's needs. That said, PacifiCorp is not precluded from procuring long-term resources that provide extra benefits if KU1 is delayed or cancelled.

Against the backdrop of future uncertainties that PacifiCorp faces, the status of KU1 is a relatively small factor. PacifiCorp's portfolio already includes 19 coal and gas-fired units that are in excess of 200 MW. All of these units periodically experience unplanned outages and may be unavailable for periods ranging from hours to days. While the uncertainty associated with KU1 at this point is currently higher than for existing units, PacifiCorp actively manages its fleet, fuel supply, and market position in response to one or more large units going offline. As a result, responding to the availability of KU1 is comparable to the portfolio management PacifiCorp already performs from day to day. Similarly, while the KU1 project will impact supply on PacifiCorp's system by up to 500 MW, a change in natural gas prices would impact the roughly four gigawatts of natural gas-fired resources in PacifiCorp's portfolio, as well as the much larger quantity of natural gas-fired

resources across the west that influence market prices. Similarly, changes in PacifiCorp's load or loads of other utilities also influence market prices, and KU1's size pales in comparison with the uncertainty in the expansion of data center demand across the west. Recent changes in federal tax policies and environmental compliance requirements have also repeatedly changed PacifiCorp's planning and procurement over the last several years. As a result, the range of possible future conditions considered in price-policy or load scenario analysis is far broader than the uncertainty associated with KU1, making KU1 just one factor among many in other long-term resource decisions.

While KU1 is projected to come online on time and operate as expected in the 2025 IRP Update preferred portfolio, PacifiCorp is also continuing to assess two different potential outcomes. First, the "No Natrium" variant identifies a long-term resource plan based on the assumption that KU1 never achieves commercial operation. This provides an indication of long-term resources changes that might be more cost-effective if Natrium does not reach commercial operation. A second view would keep the 2025 IRP Update preferred portfolio but remove KU1 before conducting hourly dispatch analysis and stochastic analysis. This would not allow the model to adapt resource selections to the absence of the output from KU1 and provides an indication of the incremental costs if KU1 continues to be forecasted as part of the portfolio but ultimately fails to achieve commercial operation. Between these two outcomes are potential intermediate resource changes which should provide some benefits with reduced incremental costs under either KU1 outcome. Because it does not involve changes in portfolio selection this second view is not included in the 2025 IRP Update but could be useful in assessing the cost-effectiveness of specific near-term resource changes.

The "No Natrium" variant in the 2025 IRP Update has relatively little change in wind and solar resources, as these resources on their own cannot replicate KU1's generation profile. Because of the flexibility resulting from its thermal storage capability, KU1 is expected to be able to maximize its output during hours when thermal resources are on the margin and can be backed down. By contrast, on their own, additional wind and solar resources would likely have high output when existing renewable resources are already plentiful and low output when existing renewable resources are limited and reliance on coal and natural gas is high, likely resulting in more curtailment and less displacement of coal and gas relative to KU1.

PacifiCorp will continue to monitor the development of KU1. Given the strong backing of TerraPower, favorable state and local interest, the permitting and siting progress made to date, and PacifiCorp's role in providing a surplus interconnection and as an offtaker, it is reasonable to anticipate KU1's success. That said, PacifiCorp will also continue to evaluate other long-term resource options. As with any long-term resource decision, the goal is to identify resources which are economic under a range of possible future conditions, of which the projected status of KU1 is one. Resources which provide greater value in the absence of KU1 are likely to also provide greater value as a result of load growth, increased market prices, or restrictions on the dispatch of natural gas or coal-fired resources. The key question is whether these possible upsides outweigh the incremental costs of that resource under expected or less-favorable conditions. Even if it is unlikely to be the biggest driver of the economics of long-term resources, as a tangible data point, the status of KU1 can act as a surrogate for more complex drivers of resource value. But, as with any long-term resource decision that is not wildly beneficial, there is no universal axiom to balance different possible futures and the decision to move forward or not.

Boardman to Hemingway Transmission Redirects

Highlighted Studies

The most relevant studies in the 2025 IRP Update to B2H Redirects analysis are:

- Base MN (preferred portfolio)
- B2H redirects sensitivity

These studies are explored in the alternative path case analysis section at the end of this chapter. The discussion below explores key factors regarding redirects of PacifiCorp's existing transmission rights to align with the new transfer capability associated with the Boardman to Hemingway (B2H) transmission line.

Key Factors Impacting Boardman-to-Hemingway Transmission Redirects

The B2H transmission line will extend from the Hemingway substation in southwest Idaho to Bonneville Power Administration's (BPA) Longhorn substation, which is just east of the city of Boardman. The Longhorn substation already includes connections to existing 500 kV and 230 kV transmission lines owned by BPA.

PacifiCorp currently uses a combination of its own transmission assets, contracts with Idaho Power Company, and contracts with BPA to transfer power from the east side of PacifiCorp's system to its retail customers on the west side of its system. For east-to-west transfers, the B2H transmission line will only allow PacifiCorp to transfer more power from Hemingway to Longhorn. To reach Hemingway from the east side of its system, PacifiCorp has negotiated an asset transfer with Idaho Power Company, providing PacifiCorp with increased ownership of transmission assets between southeast Idaho (where PacifiCorp has several transmission lines and substations) and the Hemingway substation where B2H originates. In exchange, Idaho Power Company will receive a share of PacifiCorp's transmission assets currently used to serve BPA load in southeast Idaho, as well as assets connecting southeast Idaho to Four Corners[3], which provides access to resources and markets in the southwest.

The western terminus of the B2H line, at Longhorn, does not connect to PacifiCorp's retail load. PacifiCorp has existing transmission contracts with BPA that enable transfers across BPA's system to various points of delivery where PacifiCorp has load or transmission that can reach load. PacifiCorp has submitted redirect requests to BPA which would shift the point of receipt for several transmission contracts to the Longhorn substation. Because BPA has been revising its transmission study process, it has not yet acted upon PacifiCorp's requests, and there is no clear timeline for it to do so.

While the flexibility provided by redirects can be valuable, right-sizing transmission rights to schedule power to go the locations that need it most can also be valuable. Balancing PacifiCorp's

[3] Four Corners is the point of convergence between the southwestern corner of Colorado, the southeastern corner of Utah, the northeastern corner of Arizona, and the northwestern corner of New Mexico.

array of resources and transmission rights is complex, and different outcomes may be preferrable depending on the location of different resource alternatives.

Further complicating these decisions are requests PacifiCorp has received for load service in the vicinity of Longhorn, which could be served without requiring BPA transmission service out of the Longhorn substation. PacifiCorp's pending redirect requests with BPA are less than its share of the westbound rights on B2H. The need for various combinations of existing and redirected delivery points is influenced by many variables that can change over time (i.e., changes in load growth in specific locations, changes in the location of available new resources, cost and timing of network upgrades, etc.) which will need to be considered when BPA offers service for the redirect requests. At that time, PacifiCorp will need to evaluate, based on the facts and circumstances known, whether it will accept or decline offers for service for some or all of the redirect requests that are pending. If PacifiCorp declines service for some or all of the redirect requests, it could leave more of PacifiCorp westbound B2H transmission rights for load service in the Longhorn area.

B2H is a key element in enhancing the reliability and capability of the regional transmission grid, beyond just the individual transfer rights PacifiCorp would receive between Hemingway and Longhorn. To that end, B2H will enable BPA to grant transmission rights that enable PacifiCorp to serve additional load in its central Oregon service territory, which includes the cities of Bend and Prineville. These incremental rights are independent from the redirect requests described above and are associated with rights on existing transmission infrastructure that B2H enables. B2H will also enable Idaho Power Company to grant PacifiCorp additional eastbound transmission rights from northeast Oregon to the Borah substation in southeast Idaho that are not tied to PacifiCorp's eastbound share of B2H itself.

The evolving needs and options described above influence how B2H can most effectively be used by PacifiCorp to serve its customers. At some point BPA will offer service in response to PacifiCorp's redirect requests, which may or may not require an unknown amount of network upgrades with a start date that reflects how long it might take BPA to complete those upgrades. At that time, PacifiCorp will need to determine whether each of its redirect requests is still the best alternative for its customers.

Carbon Capture and Sequestration

Highlighted Studies

The most relevant studies in the 2025 IRP Update to CCS analysis are:

- Base MN (preferred portfolio)
- No CCS variant

These studies are explored in the alternative path case analysis section at the end of this chapter. The discussion below explores key factors regarding carbon capture and sequestration.

Key Factors Impacting CCS

The 2025 IRP Update selected an amine-based carbon capture retrofit at Jim Bridger Units 3 and 4 in the preferred portfolio. Despite the increase in capital and operating costs and an increase to the auxiliary load relative to what was assumed in the 2025 IRP, the preferred portfolio still demonstrates a $471m benefit over the No CCS variant option. That said, there exists a broad set of risks inherent to developing a full carbon capture and sequestration (CCS) project at this scale that need to be considered and mitigated before such a project could move forward.

These include, but are not limited to, significant uncertainty in actual capital and operational costs to construct and maintain a CCS facility; operational risks associated with the carbon capture and storage facilities; uncertainty and risk associated with CO_2 offtake liability, pricing, and the ability to negotiate favorable contract terms; future changes to federal regulations, including rules on air, water, and waste that impact the Jim Bridger plant; carbon capture equipment and CO_2 transportation and sequestration equipment; future changes to federal policy related to tax credits available under Section 45Q of the Internal Revenue Service Code; and newly emerging state policies relating to CCS and coal use. For a CCS project of this scope to be successful it will need regulatory support, strong project partners, favorable market conditions, and reasonable pricing and risk allocation among partners. If key risks cannot be appropriately mitigated, it will challenge the project development.

While the Jim Bridger carbon capture project development is in its early stages, and there remain risks and uncertainties that need to be mitigated, CCS technology has the potential to provide a low-cost, low-risk option for low-carbon dispatchable energy to customers.

Continued Coal-fired Operation

Highlighted Studies

The most relevant studies in the 2025 IRP Update to continued coal operations analysis are:

- Base MN (preferred portfolio)
- Hunter Retire variant
- All Coal Retire variant
- Dave Johnston coal sensitivity

These studies are explored in the alternative path case analysis section at the end of this chapter. The discussion below explores key factors regarding continued coal operations.

Key Factors impacting Continued Coal-fired Operations

PacifiCorp continuously evaluates its coal-fired units and endogenously considers retirements of all existing majority-owned coal-fired plants in the 2025 IRP and 2025 IRP update modeling. Endogenous decisions incorporate the best available information regarding coal contracts and prices, environmental policies, market conditions, and loads. Key factors that might drive changes to unit selections include coal costs and availability, ongoing maintenance requirements, and both

the fixed costs and dispatch changes necessary to comply with evolving environmental compliance requirements. In addition, evolving technologies might change the relative value of thermal generation in the future.

As described in Chapter 8, PacifiCorp is evaluating the compliance obligations of the Dave Johnson plant with respect to Clean Water Act Effluent Limitation Guidelines for Steam Power as well as Regional Haze requirements. The purpose of the sensitivity analysis described in this chapter is to inform the evaluation of these compliance obligations.

Future Coal Decisions

While several Dave Johnston units have near-term compliance requirements and pending decisions related to natural gas conversion, retirement, or continued coal-fired operation, the essential decision-making process is similar for all of the majority-owned coal-fired resources in PacifiCorp's fleet. Coal-fired resources that do not have specific environmental compliance obligations are modeled with increased costs, reflective of a major overhaul roughly every four years. Smaller fixed costs are modeled in years without a major overhaul. These periodic expenses could result in a resource being retired if lower-cost sources of capacity and energy are available. The cost of continued operation at any individual unit could increase if additional environmental obligations take effect or if the cost of maintenance increases. Before making appreciable expenditures to continue coal-fired operation, PacifiCorp would revisit the assumptions and outcomes in the IRP for cost-effectiveness, particularly if the associated expenditures are large enough that operation would need to extend into future overhaul cycles. Each IRP evaluates the ongoing operation of these resources, relative to retirement or major operational changes like natural gas conversion. The ultimate decision-making generally occurs outside of the IRP, based on the best available information at the time the commitment is made.

New Natural Gas-fired Resource Procurement

Highlighted Studies

The most relevant studies in the 2025 IRP Update to new natural gas procurement path analysis are:

- Base MN (preferred portfolio)
- Low Gas, No Carbon Price
- Hunter Retire variant
- All Coal Retire variant
- B2H Redirects sensitivity

These studies are explored in the alternative path case analysis section at the end of this chapter. The discussion below explores key factors regarding new gas procurement.

Key Factors Impacting New Natural Gas Resource Procurement

Natural gas–fired resources are important for resource adequacy and reliability because they are fully dispatchable, grid-forming, and provide flexibility to integrate renewable energy resources. There are significant steps and considerations required in order to support the reintroduction of natural gas–fired resources as plausible supply-side options for the preferred portfolio. These include a screening of potential siting locations and a review of air permitting constraints related to designated non-attainment areas and state-specific restrictions on carbon-emitting generation resources.

IRP modeling represents a range of costs and risks, and PacifiCorp recognizes that current policies and regulations may not prevail for the assumed forty-year life of a new natural gas-fired facility. Conversion of existing assets to natural gas typically costs a fraction of a new natural gas-fired facility and can be economic even if retirement or major modifications were required several years in the future. This economic robustness is less likely to be the case for a new facility.

There are several possible emissions compliance pathways that could become relevant under future regulations. These include operational restrictions, emission costs, fuel switching, and carbon capture.

The Clean Air Act 111(b) rule was finalized in April 2024 and is currently stayed, pending litigation. Under this rule, maximum annual capacity factor limits of 20-40% applied to new natural gas-fired resources based on the efficiency of the plant and fuel type. Wind, solar, and short-duration energy storage can meet utility requirements in many hours of a given day while leaving gaps that are difficult to fill without long-duration storage or dispatchable resources. Diversity and balance are key to managing annual capacity factor requirements.

Emission costs can be easier to adapt to as they impose financial considerations rather than hard limits. This allows for the role of a natural gas resource in a portfolio to evolve over time while continuing to support reliability. Some 2025 IRP Update portfolios developed using the social cost of greenhouse gases (SCGHG) included limited amounts of natural gas-fired resources, indicating that these resources could play a key role even with very high emission costs.

Switching from natural gas to renewable or non-fossil fuels may require major investments in transportation and other infrastructure depending on the specific alternative fuel. The 2025 IRP Update contemplates two configurations of hydrogen storage: underground caverns, which are relatively low-cost but require geologic conditions that are uncommon, and high pressure tanks, which have higher costs but can be located anywhere. While hydrogen is relatively straightforward to produce, it has high storage and transportation costs. Other possible fuels include biodiesel, and renewable natural gas. Both of these fuels are more expensive than fossil natural gas and have limited production that is dwarfed by utility-scale generation demand. Biodiesel can also produce higher emissions of nitrous oxides relative to natural gas. To the extent fuel switching results in a large reduction in operating hours, the level of supply needed may be much less than was required to support forecasted natural gas-fired operation. That said, having a firm fuel supply is important given the key role of dispatchable resources in helping to cover long-duration outage risks.

Finally, carbon capture and sequestration could allow for the continued use of existing fuel supplies while removing most of the associated carbon dioxide emissions. The fixed cost of carbon capture and sequestration is projected to be very high, and the technology results in incremental variable costs, increased fuel consumption, and reduced generation output. The technology also has many uncertainties. While carbon capture and sequestration at Jim Bridger units 3 and 4 is

economic in the 2025 IRP Update, this is largely the result of the 45Q tax credit, which is only available for projects where construction begins prior to 2033. Carbon capture equipment would need to be installed at a resource with a very high annual capacity factor to justify the high fixed cost of installation. Natural gas-fired resources in PacifiCorp's recent IRPs have typically had intermediate to low capacity factors and moderate to high fuel costs.

While some options exist that could allow new natural gas-fired resources to continue to operate if major restrictions were imposed, there is a risk that it could reduce the value of the resource. Any new natural gas-fired resource would need careful consideration of their risks relative to possible alternatives.

Regional Resource Adequacy

PacifiCorp's 2025 IRP Update includes long-term capacity additions that align with the planning reserve margin and resource capacity contribution values developed by the Western Resource Adequacy Program (WRAP). While PacifiCorp has provided the required two-year notice that it is exiting WRAP ahead of the first binding compliance season in November 2027, it continues to see value in working with regional partners to increase reliability and avoid extreme outcomes from increasingly volatile western markets. Because consideration of alternatives is still underway, PacifiCorp is continuing to use estimates from WRAP in the interim. There is also the possibility that PacifiCorp could reenter WRAP by September 2026 and participate in the first financially binding season in November 2027. There is a risk that any eventual program PacifiCorp participates in will have different requirements than those currently assumed. However, one of the concerns PacifiCorp raised leading up to its exit from WRAP was the lack of certainty about upcoming requirements within WRAP itself, as these are updated ahead of each compliance season and have varied significantly from year to year.

There are a couple of key factors that can degrade PacifiCorp's resource adequacy compliance position:

- Capacity contribution for wind, solar, and storage
- Thermal resource forced outages and temperature-dependence
- Planning reserve margin requirements

Regardless of the driver of the resource adequacy shortfall, the solution is to procure additional resources (including demand-side resources, such as energy efficiency or demand response). Where available and cost-effective, resources which are projected to be less impacted by saturation and peak load impacts provide greater value and the highest risk reduction.

Capacity Contribution for Wind, Solar, and Storage

PacifiCorp's 2025 IRP included projected WRAP capacity contribution values for wind, solar, and energy-limited resources like storage and demand response. These values were based on forecasted changes to the overall regional resource mix over time.[4] Each of these resource types can only

[4] See PacifiCorp's 2025 IRP. Volume II. Appendix K (Capacity Contribution)

assist in a portion of all possible hours with reliability risks. Wind resources enhance reliability when the wind blows, while solar resources enhance reliability during the daytime, and short-duration energy storage primarily helps during the first few hours of a reliability shortfall. There are some opportunities for these resources to work in concert, as wind and solar resources can help to reduce outage duration such that it remains within the capability of short-duration energy storage. But, as the share of each of these resource types grows, the overall risks shift away from periods that these resources can cover and into periods in which their incremental reliability benefits are reduced.

Under WRAP, capacity contribution values are essentially average values for each technology type, with some geographic and project-specific differentiation. When wind, solar, or storage increases as a share of the overall portfolio, the marginal benefits of incremental resources will generally be smaller than the previous average. This would result in a decline in the capacity contribution for that technology type, and a reduction in the average value attributed to each resource of that type. If faced with declining capacity contributions for its existing portfolio, a utility would need to procure additional capacity just to cover existing load. These outcomes are dependent on the regional resource mix so they are outside of the control of an individual utility.

Thermal Resource Forced Outages and Temperature-Dependence

While thermal resources (and long-duration storage) are not subject to saturation effects, they may experience reductions in their capacity contributions based on their recent historical performance. In general, these resources receive capacity contributions based on their forced outage rate. Within WRAP, that forced outage rate was measured during top net load demand hours (load net of wind and solar generation). If a thermal resource experiences a prolonged outage that limits its availability during these top hours in a given year, it will receive a reduced capacity contribution. This provides an incentive to keep thermal resources available whenever possible.

Forced outages at individual units can be managed within the context of a utility's portfolio. Swings in a utility's overall position are more likely if a broad portion of the utility's thermal fleet is subject to similar risks, such as temperature-related derates. The maximum output of combustion turbines is usually limited based on ambient conditions, with output dropping as temperature increases. While the output from steam turbines is not typically impacted by ambient conditions directly, they can experience restrictions related to cooling water temperatures or air-cooled condensers. High ambient temperatures and prolonged operation at maximum output can also negatively impact individual sub-systems within a plant, contributing to a higher risk of forced outages. As with wind, solar, and storage resources, if thermal resources have heightened risks during the conditions with the greatest need, their capacity contributions will decline. Adapting to maintain or increase output during such conditions may be possible, but it is likely to come at a cost.

Planning Reserve Margin Requirements

Under WRAP, planning reserve margins are applied to each utility's non-coincident peak load, with specific requirements for each of nine months across the year[5]. Resource capacity contribution values are also tied to planning reserve margins. An increase in capacity contribution may be offset by the associated increase in planning reserve margins. With non-coincident peak loads, different participating utilities experience the peak requirements at different times. A smaller pool of resources can serve those utilities, as the excess supply needed to cover one utility's elevated need can also be used to cover the elevated need of a different utility. During region-wide weather events, many utilities may experience peak load conditions at the same time. While this may be uncommon historically, it may increase in the future, or it may be identified as a sufficiently likely risk to drive planning and resource adequacy requirements. Should that occur, planning reserve margins would need to increase, to cover the coincident needs of all participants in the most constrained period, rather than a series of non-coincident requirements.

Short-term market reliance

PacifiCorp uses short-term market purchases to meet any remaining difference between its contracted resources and its load. Because long-term resource commitments typically require contracts executed several years prior to the scheduled commercial operation date, the IRP does not identify long-term resource additions in the first few years. Estimates of the remaining near-term market position are identified in Chapter 7, and amount to just under 1,000 MW in 2027, falling to under 500 MW in 2028-2029.[6] Over the longer term, procurement of long-term resources is possible but there is the opportunity to use either long-term resources or short-term market purchases to meet a portion of PacifiCorp's capacity requirements. The resource portfolio selection in the 2025 IRP Update allows for capacity to be met with an "annual block product" starting in 2030. This is intended to represent short-term market purchases.

Block purchases were available for the model to select in 25 MW increments or "blocks" up to 500 MW per year in Mid-C and Wyoming East from 2030 onward, priced at Mid-C and Palo Verde heavy-load hour (HLH) and light-load hour (LLH) forward prices. The purchase only applies to the months of July and December where, if selected, the model was required to pay for the block purchase in all hours in those months in a given year. In reality, while HLH and LLH block products are the most widely traded, a variety of other transaction types exist, including tolling agreements, hydro slices, resource adequacy agreements, and custom products covering peak hours. Available supply, cost, and operating characteristics vary widely. Unlike typical long-term resources, block market purchases represent a commitment for a single year only. In actual operation, the flexibility of short-term market products allows PacifiCorp to transact to better align its resources and load across individual months, which is particularly valuable when needs are seasonal or for a small number of years.

[5] Sumer: June-September, winter: November through March
[6] See Chapter 7, Table 7.11 – 2025 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

Both cost and available quantity for short-term market purchases are uncertain over the long-term, but transactions can be entered on a forward basis, typically up to three years advance. PacifiCorp's market prices for electricity and natural gas are a forecast of forward prices, which refers to the price today for delivery in a future period. For example, a buyer and seller agree in March 2026 on a price for a volume to be delivered in July 2027. Most of PacifiCorp's short-term market purchases are entered within two years of delivery. As a result, while PacifiCorp has a forecast of market prices for 2030, it would not generally begin making short-term purchases to help meet its 2030 requirements until 2028. In the meantime, market prices could increase dramatically, or the pool of counterparties looking to sell power in 2030 could diminish.

PacifiCorp has a range of long-term resource options today that could be online in 2030. But if it forgoes those long-term options and plans to meet a portion of its 2030 need with short-term market purchases, fewer long-term options will remain available as 2030 approaches, and those that are possible may have higher costs for expedited construction. If PacifiCorp is unable to secure short-term market purchases for 2030 in 2028 there could be very limited alternatives, and potentially very high costs. While forward markets have periodically experienced price swings indicative of heightened uncertainty and risk, it is not possible to identify whether adequate physical supply will continue to be available in the future. Because of the geographic diversity of PacifiCorp's transmission system, it is able to access widely dispersed markets and counterparties and is not reliant upon a single market.

There are risks with continued reliance on short-term market purchases, but there are definite costs from procuring additional long-term resources to meet capacity requirements. Additional resources can provide benefits in the form of lower-cost energy supply, but this generally only offsets a portion of their cost, resulting in a net increase in revenue requirement and upward pressure on retail rates. This is particularly true for capacity-focused resources like energy storage or natural gas plants. Starting with PacifiCorp's 2021 IRP, short-term market purchase limits were reduced due to concerns about the western resource mix becoming increasingly reliant on variable and short-duration resources. Since that time, extreme weather events and the potential for rapid data center load growth have increased pressure on markets. These factors have also increased pressure on long-term resource supply. The IRP includes a discrete limit on short-term market purchases, but in practice, each long-term resource decision is lumpy. As a result, long-term resource procurement today must also be balanced against the possible cost and risks of waiting and seeking additional long-term resources in the next couple years.

Alternative Path Case Review

Base MN (preferred portfolio)

The Base MN portfolio is PacifiCorp's preferred portfolio in the 2025 IRP update, as extensively discussed in Chapter 7. The preferred portfolio includes large amounts of renewable energy selections, short and long duration storage, Kemmerer Unit 1, new gas, continued coal-fired operation and the installation of CCS technology at Jim Bridger. The discussion below of the variants and sensitivities presents an exploration of how changes to specific assumptions related to the suite of resources in the preferred portfolio may impact ongoing planning and decision making. At the same time, the risks and benefits related to the key decisions and factors presented

in the above discussion hold true for the preferred portfolio. The ability of PacifiCorp to acquire these types of resources at the modeled costs and benefits will continue to be evaluated during procurement. PacifiCorp's ability to acquire resources which are directionally aligned with the preferred portfolio strategy is dependent on all of the factors outlined above.

Hunter Retire

As shown in Chapter 7, the Hunter Retire portfolio initially selects additional battery storage capacity, followed by more moderate new gas selections. Generally, this indicates that replacing some coal capacity requires lower additions of flexible capacity resources than a portfolio which must replace all coal capacity. This portfolio still indicates that flexible capacity remains critical to system operations. At the same time, there is some value in storage capacity when this storage capacity is able to charge during low cost times and is coupled with flexible dispatch as needed. To the extent that storage capacity continues to be available to PacifiCorp, this portfolio suggests that some coupling of storage with energy is important for reliability. While the cost differential does not suggest PacifiCorp should begin contemplating an early retirement of the Hunter plant, this portfolio does highlight the importance of continuing to pursue flexible generation and storage. For a discussion of the risks and near term implications of new gas siting, coal fired operations and dispatchable thermal procurement see the Continued Coal-fired Operations and New Natural Gas Procurement sections above.

All Coal Retire

As discussed in chapter 7, the retirement of all coal leads to a decrease in dispatchable resources by the end of the horizon, with only a moderate increase in installed energy resources. Whereas the Hunter Retire portfolio included a relatively balanced mix of storage capacity and flexible capacity, the retired coal capacity is replaced with new gas resources. This indicates flexible capacity remains a critical component of a reliable system for PacifiCorp. If PacifiCorp were to anticipate retiring coal facilities by 2032, it is likely that PacifiCorp would need to begin the process of working to procure new, flexible capacity within the action plan window, which is not something PacifiCorp anticipates doing due to the large cost differential between this portfolio and the preferred portfolio. However, given the indication that dispatchable resources remain a key component of a reliable system, this portfolio suggests PacifiCorp should continue evaluating flexible dispatch capacity resources for procurement. For a discussion of the risks and near term implications of new gas siting, coal fired operations and dispatchable thermal procurement see the Continued Coal-fired Operations and New Natural Gas Procurement sections above.

No Future Technology

The No Future Technology portfolio removes new nuclear, hydrogen storage, 100-hour storage, and biodiesel peaking resources as options. This leads to significant changes to storage selections, as well as the removal of Kemmerer Unit 1 energy from the portfolio mix. The change in availability for long duration storage leads to an increase in reliance on new gas peaking resources. Additionally, as shown in Chapter 7, this portfolio leads to an increase in coal variable costs, suggesting a need for long-duration capacity. This indicates that PacifiCorp relies on the availability of resources which can be dispatched or can shift energy over more than 4 hours. PacifiCorp needs to continue to monitor the development of storage technologies in order to capitalize on the ability to procure some version of storage which surpasses 8 hours in duration. Should these technologies not be viable, PacifiCorp would need to continue to look to flexible dispatchable capacity to meet reliability needs. For more detail related to new technology risks and

the considerations related to procurement of these technologies see the No Future Technology discussion above.

No Kemmerer Unit 1

Removal of Kemmerer Unit 1 leads to a shift in long duration storage selections from the end of the horizon into the intermediate term. Additionally, this portfolio selects additional new gas capacity to replace the energy generated by Kemmerer Unit 1. Somewhat like the No Future Technology portfolio, this portfolio shows the impact of long duration storage and flexible dispatchable capacity on system reliability in the absence of Kemmerer Unit 1. Also, like the no future technology case, the absence of Kemmerer Unit 1 results in much higher coal and gas dispatch in order to replace the non-emitting energy from Kemmerer Unit 1. This indicates that PacifiCorp continues to rely on high capacity factor resources during many hours. It is imperative PacifiCorp continue to evaluate the ongoing development of the Kemmerer Unit 1 project and consider various alternatives should the risks outlined in the Kemmerer Unit 1 section above result in the project not moving forward.

No CCS

The No CCS portfolio outlines the changes that would happen if Jim Bridger 3 and 4 did not install carbon capture and sequestration technology. In this case, there is less storage acquired because of the increased capacity of Jim Bridger 3 and 4 relative to the portfolio when CCS is installed. From a reliability perspective, there is only a small impact on the portfolio selections with or without CCS. Although CCS runs at a very high capacity factor in order to capture as much tax credit as possible, overall system reliability is able to be achieved without CCS. Ultimately, the viability of CCS is heavily dependent on the factors discussed in the CCS section above. What this study indicates is that CCS can be a valuable component of the system, and that if it were not to be viable as anticipated, PacifiCorp is likely able to pivot with little to no impact to reliability.

High Gas, High Carbon Prices

The HH portfolio indicates that in a future with high fuels prices, significant investment in renewable energy resources is the most economic path forward. This pricing future would also make operating thermal plants less economic. In order to achieve reliability with increased variable energy resources, additional storage is needed, and the amount of new renewable resource procurement is approximately 50% higher than the level in the preferred portfolio. The ability of PacifiCorp to procure this many incremental wind and solar resources is dependent on the factors outlined in the wind and solar procurement discussion above. This portfolio indicates that large amounts of renewables would be the correct path forward if there were high coal and gas prices, and that PacifiCorp should continue to work to acquire cost-effective renewable resources dependent upon the risks and conditions outlined above. While this portfolio indicates new renewable resources would be needed, it does continue to operate existing thermal resources, largely as in the preferred portfolio. This suggests that, despite very high operating costs in this scenario, thermal resources continue to be important for reliability. For more detail related to wind and solar procurement risks and considerations related to the potential continued benefit of thermal operation see the Wind and Solar Procurement and Continued Coal-Fire operations sections above.

Low Gas, No Carbon Prices

The LN portfolio indicates that in a future with low gas prices, the most cost-effective path forward is procuring incrementally more new gas resources, and incrementally fewer renewable energy

resources. Additionally, this portfolio indicates a higher reliance on 100-hour storage than the preferred portfolio. Because of this, the portfolio selected for this future presents a higher fuels volatility risk than does the preferred portfolio. The ability to site new gas, procure sufficient gas transportation and supply, and operate incrementally more gas is influenced by the risks outlined in the New Gas section above. Because this portfolio builds incrementally fewer resources overall, and leverages more energy from existing emitting resources, there is potential for cost savings from building fewer resources. At the same time, this presents significant cost risk should prices in the future be higher than the price under which this portfolio was developed, as seen in the risk adjustment under a medium fuels cost future. Ultimately, this portfolio demonstrates that PacifiCorp should continue to work to acquire cost-effective fuels for coal and gas operations, while balancing that with procurement of new cost-effective resources. For more detail related to new gas procurement risks and considerations related to the potential continued benefit of thermal operation see the New Gas Procurement and Continued Coal-Fire operations sections above.

B2H Redirects Sensitivity

This sensitivity explores the resource selections PacifiCorp may make if BPA grants PacifiCorp cost-effective transmission re-direct rights to move power from Longhorn to other portions of the PacifiCorp system. This study suggests that fewer overall resources would be required to maintain system reliability with these additional transmission rights. An ability to more effectively move existing generation into existing retail load provides some benefit to the system as shown in this study. The study increases flexible dispatchable capacity and reduces renewable energy and storage selections, suggesting that this transmission is best utilized when paired with flexible resources. Overall, this portfolio indicates that PacifiCorp should continue working with BPA to acquire redirect rights, assuming a reasonable cost structure can be agreed to. Additionally, this portfolio indicates the importance of flexible dispatch to the system and suggests that PacifiCorp should continue to evaluate these types of opportunities. For more detail related to new gas procurement risks see the New Gas Procurement section above.

Federal Tax Credit Sensitivity

This sensitivity explores what path PacifiCorp may consider taking if federal tax credits were to be re-introduced in 2030. If federal tax credits on renewable energy resources were to come back in 2030, significant new renewable resources would be highly cost-effective and selected in modeling. This sensitivity also reduces the amount of new gas which is selected by the model. There is a greater reliance on 100-hour storage in this case as well because of the very high amount of new renewable energy selected. Should PacifiCorp be able to procure projects that reflect tax-advantaged pricing, this sensitivity indicates PacifiCorp should do so. The ability of PacifiCorp to acquire large amounts of renewable energy resources is highly dependent on the factors outlined in the above section on Wind and Solar procurement. Additionally, this future relies on long duration storage to capture all of the benefits of the incremental wind and solar selections and is subject to the factors discussed in the Future Technology section above.

Dave Johnston Coal-Fired Sensitivity

This sensitivity explores the actions PacifiCorp should consider taking if Dave Johnston units 1, 2, and 3[7] are able to continue coal-fired operation. The ability of Dave Johnston unit 3 to continue

[7] Dave Johnston unit 4 is already eligible to continue coal-fired operation in the preferred portfolio

operating leads to lower overall new resource selection. By continuing to operate Dave Johnston units 1, 2, and 3 on coal, PacifiCorp generally incurs lower incremental costs than the procurement of new resources. This portfolio selects less new gas than the preferred portfolio and also forgoes the expense to gas convert Dave Johnston units 1 and 2. This reduced capital and proxy cost is a benefit to the system. This sensitivity suggests that PacifiCorp should explore multiple options for the future operations of current thermal plants in order to ensure the best outcomes for customers. Further studies related to these units will be included in the 2027 IRP. For more detail related to the risk and potential benefit of continued coal operations, see the Continued Coal-Fire operations section above.

No HB 2021 Counterfactual

This study explores what resource changes are indicated should Oregon's HB 2021 decarbonization targets either be repealed or if compliance were no longer required. In a world where Oregon's energy is able to be served by any resource type, barring coal (due to SB 1547's no-coal mandate), far fewer renewable selections occur. The majority of these reductions occur in the near term, with approximately 2/3 of the reduction occurring by 2030. In a world without HB 2021, far fewer low capacity factor variable energy resources are procured, and PacifiCorp could delay procurement. This could potentially result in lower costs to customers as NREL projected costs decrease over time (although as discussed in the Wind and Solar Procurement section above, this does not guarantee PacifiCorp will receive bids reflecting lower input costs). For additional perspective regarding a future without HB 2021, see Appendix D, the Clean Energy Plan Update.

Portfolio Overview

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the 2025 IRP Update. 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 Update shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions. State and federal environmental policy also influences resource selections in the 2025 IRP Update. 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 in Table 9.X, PacifiCorp identifies the planning scenario assumption affecting both short-term (2026-2034) and long-term (2035-2045) resource strategies.

Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future

unfolds."[8] 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.

PacifiCorp's 2025 IRP Update 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.

Table 9.1 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2026-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Legislation forces all coal to retire by 2032	Refer to Chapter 7, variant "All Coal Retire"	• With all coal units forced to retire on 1/1/2032, 3,346 MW of nameplate coal capacity would retire in 2032. • Significant additional incremental resources are added to the portfolio, dominated by 2,452 MW of new gas resources within the near-term acquisition window.	• In the long-term acquisition window, resource additions are similar to the preferred portfolio.
No Natrium™ Advanced Nuclear Demonstration Project in 2032, and no other nuclear projects	Refer to Chapter 7, variant "No Kemmerer Unit 1" and the above analysis	• Without Kemmerer Unit 1, moderate amounts of renewable resources and storage are added to the portfolio by 2032. • In 2033 and 2034, additional incremental storage resources are added to the portfolio.	• From 2035 on, incremental resource additions are dominated by new gas units. • Batteries fall out of the portfolio in 2041 through 2045 as incremental amounts of these resources are built earlier to replace Kemmerer Unit 1.

[8] 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.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2026-2034)	Long Term Resource Acquisition Strategy (2035-2045)
Technologies such as nuclear, hydrogen storage, 100-hour battery storage and biodiesel peaking do not become commercially viable	Refer to Chapter 7, variant "No Future Technology" and the above analysis	• The nuclear and 100-hour battery selections in the preferred portfolio are replaced by a significant amount of 4-hour battery and moderate amounts of solar. • In the near-term acquisition window, the capacity of future technology that falls out of the portfolio is greater than the capacity of incremental resources selected to replace them.	• While the type, timing and location of resources change as is required by the absence of nuclear and 100-hour battery, the amount of incremental resource additions in the long-term acquisition window is similar to the preferred portfolio. • Incrementally more gas is selected, suggesting a lack of long-duration storage must be met with flexible capacity.
Legislation requires the Hunter plant to retire on 1/1/2031	Refer to Chapter 7, variant "Hunter Retire"	• On 1/1/2031, 1,158 MW of nameplate coal capacity retires at Hunter. • To replace the lost Hunter capacity, by 2034, selections include a significant amount of 4-hour battery and moderate amount of new gas resources.	• From 2035-2045, a small amount of new gas is added to the portfolio.
No CCS available at Jim Bridger in 2031	Refer to Chapter 7, variant "No CCS" and the above analysis	• Incremental resource selections with Jim Bridger CCS unavailable are similar to the preferred portfolio, with small changes including an increase in 4-hour battery selections • On 1/1/2031, 174 MW of nameplate capacity remains available at Jim Bridger without the installation of CCS.	• The balance of selections without CCS remain the same.
High Fuels/Market and Carbon Prices	Refer to Chapter 7, Variant "High Thermal Fuels and High CO_2 Price" and the above analysis	• The total near-term selections include an incremental 927 MW of combined wind and solar capacity. Selections also include an increase in 100-hour storage capacity and a reduction in 4-hour storage capacity.	• Acquire renewable resources. • Reduce fuel consumption and look to retire Dave Johnston 4 and Wyodak
Low Gas/Market and No Carbon Price	Refer to Chapter 7, Variant "Low Gas and No CO_2 Price" and the above analysis	• The total near-term selections are similar to the preferred portfolio with some differences in timing. • PacifiCorp would look to acquire cost effective renewables and storage.	• Procure incrementally more gas peaking resources. • Pair these with additional incremental storage resources.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2026-2034)	Long Term Resource Acquisition Strategy (2035-2045)
PacifiCorp acquires B2H redirect rights from Bonneville Power Administration	Refer to Chapter 8, sensitivity "B2H Redirects"	• The total near-term selections are similar to the preferred portfolio, with a small reduction in combined wind and solar selections.	• Overall, PacifiCorp would look to reduce renewable procurement by approximately 250 MW. • Increase new proxy gas selections by approximately 300 MW.
Oregon's HB 2021 is repealed	Refer to Chapter 8, sensitivity "No HB 2021 Counterfactual" and Appendix D	• PacifiCorp would reduce renewable energy procurement by approximately 2,100 MW. • PacifiCorp would seek to re-evaluate storage options to ensure long duration storage capacity is sufficient for reliability.	• A further reduction in renewable resource procurement is indicated.
Changes to Federal Policy lead to a re-introduction of IRA style tax credits for renewables	Refer to Chapter 8, sensitivity "2030 IRA"	• A re-introduction of tax credits in 2030 leads to an increase in renewables selections almost immediately following the tax credit implementation. • Over 800 megawatts of new renewable energy resources are indicated from 2030 to 2034. • In order to capture the additional energy generated by these resources, an additional 117 incremental megawatts of storage is installed as 100-hour storage. • An additional transmission line is required to enable these new resources	• An additional 3,054 of renewable energy resource is selected, along with an 1,100 megawatt reduction in new gas. • Transmission investments are shifted earlier in order to enable the significant new resource selections
Dave Johnston can continue to run on coal	Refer to Chapter 8, sensitivity "Dave Johnston Coal-Fired Sensitivity"	• PacifiCorp would not gas convert or retire Dave Johston units 1-3 • PacifiCorp would look at DSM investments to ensure right-sizing given the continued operation of Dave Johnston coal	• PacifiCorp would acquire incrementally less new gas

CHAPTER 10 – ACTION PLAN STATUS UPDATE

Introduction

PacifiCorp's 2025 IRP Update revisits the action plan identified in the 2025 IRP. The action plan described 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.

New to the 2025 IRP Update, the alternate path analysis is no longer included in Chapter 10. Refer to Chapter 9 – Alternate Path Analysis for a detailed discussion of future changes and considerations that could lead to real-world resource procurement that differs from the 2025 IRP Update preferred portfolio. For further discussion of portfolio similarities and differences, refer to the robustness assessment included in Chapter 8 – Sensitivities.

Table 8.1 provides an update to relevant ongoing items, primarily stemming from achievements and status changes since the filing of the 2025 IRP.

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Table 8.1 – 2025 IRP Action Plan Status Update

Action Item	1. Existing Resource Actions	Status
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.	• 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 2025 IRP preferred portfolio target exit date of December 31, 2025.	• The Department of Energy issued a 90-day order forcing Craig 1 to remain available. 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 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 close the Naughton South Ash Pond in compliance with federal regulations.	• Naughton Units 1 and 2 ceased coal operations on December 31, 2025. • PacifiCorp is on track to complete required regulatory notices and filings for conversion of Naughton Units 1 and 2 from coal to natural gas.
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. The Company is pursuing a front-end engineering design study as part of compliance with Wyoming's low carbon portfolio standard requirements as a site-specific analysis is	• PacifiCorp filed its final plan with the Wyoming Public Service Commission on March 29, 2024, as required under Wyoming House Bill 200, and continues to provide annual updates to the final plan as required. • The 2025 IRP Update includes a refreshed assessment of carbon capture technology including associated costs and derates.

	needed to better understand the feasibility of the project.	
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.	• EPA denied both Utah and Wyoming's second planning period regional haze state implementation plans in December 2024. Utah, Wyoming, PacifiCorp and other parties petitioned the denials to both EPA and the Tenth Circuit Court of Appeals. EPA granted petitions to reconsider the denials, and the Tenth Circuit Court of Appeals has abated the cases while EPA completes its reconsideration. • On September 25, 2025, PacifiCorp submitted a petition for reconsideration to EPA requesting that the agency reconsider the requirement that Dave Johnston Unit 3 shut down by December 31, 2027.
1f	**<u>Natrium™ Demonstration Project (Kemmerer Unit 1):</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 Public Utility Commission of Oregon 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 fully executed a power purchase agreement and water use and conveyance agreement with US SFR (TerraPower) in 2025. • Consistent with the specific requirements in each jurisdiction, PacifiCorp filed for approvals of the Kemmerer Unit 1 agreements. The applications are currently under review. • Wyoming's Public Service Commission approved the water use agreement in January of 2026.
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	• On January 28, 2026, the Tenth Circuit Court of Appeals agreed to continue the abatement of litigation over EPA's disapproval of Utah's state ozone transport implementation plan. The EPA has proposed

	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.	to approve other state plans for the ozone transport rule, and Utah's will be reviewed in a future rulemaking.
1i	**Federal Greenhouse Gas Emission Compliance:** • EPA finalized its regulation for existing coal-fueled steam units under Clean Air Act Section 111(d) in April 2024, though the rule has been challenged in the D.C. Circuit. • PacifiCorp will continue to update and evaluate alternatives for affected resources while the legal process continues.	• On June 17, 2025, EPA proposed to repeal the greenhouse gas emissions standards for fossil fuel-fired electric generating units, proposing to repeal the CCS requirement for existing coal units and new base load combustion turbines. PacifiCorp will continue to evaluate compliance obligations.
1j	**Dave Johnston Units 1 and 2:** • PacifiCorp's preferred portfolio selects Dave Johnston Units 1 and 2 for conversion to natural gas in 2029.	• On December 30, 2025, EPA finalized its rule extending certain compliance deadlines in a rule governing coal-fired power plants' effluent limitations guidelines and allowing for alternate timelines, if certain conditions are met, for compliance with the 2020 and 2024 effluent limitation guidelines. PacifiCorp is currently analyzing effluent limitation guidelines compliance options for the Dave Johnston plant.

Action Item	2. New Resource Actions	Status
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from 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. • The Utah Community Renewable Energy Act, enacted in 2019, allows eligible communities and PacifiCorp to develop a program to achieve a goal of net 100 percent renewable by 2030.	• On May 13, 2025, the UPSC approved PacifiCorp's application of a solicitation process for a Utah Community Renewable program. The UPSC issued an order approving the program March 4, 2026, and implementation of the program is underway..
2b	**2025 All-Source Request for Proposals:** • PacifiCorp will initiate with individual jurisdictions the process to issue as appropriate by individual jurisdiction need, one or more independent 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.[1] • Individual independent jurisdictional RFP filings will include timelines associated with the respective jurisdictions' process.	• PacifiCorp issued the 2025 Washington Situs RFP to market on September 2, 2025. Final bids were received by October 7, 2025. PacifiCorp has completed bid evaluation and is in the process of contracting shortlisted bids. On October 13, 2025, PacifiCorp issued the 2025 Oregon Situs RFP to market. PacifiCorp received final bids by November 18, 2025. PacifiCorp is in the process of evaluating bids with a target to produce a final shortlist in June.

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

Action Item	3. Transmission Action Items	Status
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.	• PacifiCorp continues to initiate local reinforcement projects.
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. These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.	• Reinforcements have been identified. A final assessment of upgrades is pending signed agreements.
3c	**Boardman to Hemingway Transmission Project**[2] • Construction of Boardman-to-Hemingway (B2H) is underway, with an expected in-service date of 12/31/2027. As required by the Oregon Public Utility Commission, PacifiCorp will provide quarterly progress reports in Docket No. LC 85 on B2H.	

[2] This item is new to the 2025 IRP Update

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th><th>Status</th></tr>
<tr><td>4a</td><td>
<u>Energy Efficiency & Demand Response 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.

<table>
<tr><th>Year</th><th>First-Year Energy Efficiency (GWh)</th><th>Annual Capacity (MW)</th></tr>
<tr><td>2025</td><td>595</td><td>92</td></tr>
<tr><td>2026</td><td>573</td><td>89</td></tr>
<tr><td>2027</td><td>597</td><td>209</td></tr>
<tr><td>2028</td><td>648</td><td>220</td></tr>
</table>

PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity selections from the preferred portfolio.[3] Capacity impacts for demand response include both summer and winter impacts within a year and are incremental to those already included as existing.[4]

</td><td>

PacifiCorp achieved an estimated 565 GWh of first-year energy efficiency savings across all states in calendar year 2025, at an annual capacity value of approximately 87 MW. This is approximately 95% to target.
As of March 2026, PacifiCorp estimates it achieved approximately 22.9 MW of incremental dispatchable demand response capacity in CY2025, or about 127% of the 2025 IRP total selections. This estimate may be updated during the state-specific demand response annual reporting process later in 2026.

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</table>

[3] A portion of cost-effective demand response resources identified in the 2025 preferred portfolio in 2025 represent planned volumes are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2013 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to existing resources or as an expansion of existing resources offered through approved programs.
[4] See Appendix D, Table D.3 of the 2025 IRP for the split out between summer and winter capacity.

	<table><tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr><tr><td>2025</td><td>18</td></tr><tr><td>2026</td><td>2</td></tr><tr><td>2027</td><td>0</td></tr><tr><td>2028</td><td>63</td></tr></table>	
Action Item	**5. Market Purchases**	**Status**
5a	**Market Purchases:** • 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: o Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. o 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. o Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.	• Since the publication of the 2025 IRP action plan, PacifiCorp has continued to transact consistently 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. • The 2025 IRP contemplated PacifiCorp's participation in the Western Resource Adequacy Program (WRAP) starting in 2028. PacifiCorp provided a two-year notice that it was exiting WRAP on October 30, 2025, ahead of the start of binding compliance in November 2027.[5] Given its exit from WRAP, PacifiCorp can continue making use of a broader range of market products than are allowed for WRAP compliance. PacifiCorp is continuing to

[5] PacifiCorp's WRAP Withdrawal Letter. October 30, 2025. Available at: https://www.westernpowerpool.org/private-media/documents/WRAP_Withdrawal_Letter_-_Oct_30_2025.pdf

		evaluate ways to manage resource supply risk through participation in regional resource adequacy programs. • Market purchases are made in accordance with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices and include a mix of the transaction types identified in item 5a.

Action Item	6. **Renewable Energy Credit (REC) Actions**	Status
6a	**<u>Renewable Portfolio Standards (RPS):</u>** • PacifiCorp may 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.	PacifiCorp will continue to evaluate the need for and reasonableness of 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

APPENDIX A – ADDITIONAL LOAD FORECAST DETAILS

The load forecast presented in Chapter 4 represents the data used for capacity expansion modeling and excludes load reductions from incremental energy efficiency resources (Class 2 DSM). The load forecast used in the 2025 IRP Update was produced in May 2023. The average annual energy growth rate for the 2024 through 2042 timeframe is 2.13 percent. Relative to the load forecast prepared for the 2025 IRP, PacifiCorp's 2041 forecasted energy requirement decreased in all jurisdictions other than Utah. Table A.1 and Table A.2 illustrate the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures (Class 2 DSM).[1]

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

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

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

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

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

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

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

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

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

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

This section provides total system and state-level forecasted retail sales summaries measured at the customer meter by customer class including load reduction projections from new energy efficiency measures from the 2025 IRP Update preferred portfolio. The average annual retail sales growth rate for the 2024 through 2042 time period is 1.23 percent.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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APPENDIX B - REGULATORY COMPLIANCE

Introduction

PacifiCorp's 2025 Integrated Resource Plan (IRP) Update complies with (1) the various state commission IRP standards and guidelines, (2) specific analytical requirements stemming from acknowledgment orders for the company's 2025 Integrated Resource Plan, (3) state commission IRP Update requirements stemming from other regulatory proceedings, (4) other ongoing IRP acknowledgement order requirements as applicable.

The focus for this report is to reference each rule, guideline, and requirement uniquely pertinent to the 2025 IRP Update filing. For a complete review of every compliance element, please refer to Volume II, Appendix B of the 2025 IRP, published March 31, 2025.

Included in this appendix are the following tables:

- Table B.1 - Provides an overview and comparison of the rules in each state IRP submission.[1] The table is divided into topical subsections as follows:
  - (a) Source
  - (b) Filing Requirements
  - (c) Frequency
  - (d) Commission Response
  - (e) Process
  - (f) Focus
  - (g) Elements

- Table B.2 - Provides a description of how PacifiCorp addressed the 2025 IRP order requirements and other commission directives.[2]

General Compliance

PacifiCorp prepares an IRP Update on a biennial basis (even-numbered years), spaced between filings of the full integrated resource plan (odd-numbered years). The IRP Update is traditionally filed with all state commissions whether or not it is explicitly required in a particular state.

Timing and Public Input

New requirements for the 2027 IRP have driven an acceleration of the public input process, which historically was not initiated until after the filing of the prior IRP Update. This acceleration is a

[1] California Public Utilities Code Section 454.5 allows utility with less than 500,000 customers in the state to request an exemption from filing an IRP. However, PacifiCorp files its IRP and IRP supplements with the California Public Utilities Commission to address the company plan for compliance with the California RPS requirements.
[2] "Other commission directives" includes any distinct directives relevant to this IRP Update not captured in an acknowledgement or stemming from another venue.

continuation of a trend that began with the company's 2023 IRP. Due to this timing and the regulatory obligations of this 2025 IRP Update in particular, distribution to all states takes on new relevance.

In the 2023 IRP, PacifiCorp advanced the start of the public input meeting series from May to February, fully incorporating public materials regarding the development of the Conservation Potential Assessment and providing an opportunity to discuss IRP topics earlier in the process. In the 2025 IRP cycle, the schedule was accelerated again to January, and IRP topics took on a more significant role in the early meetings, with the objective of presenting important subjects early and often.

For the 2027 IRP, the beginning of the public input process was accelerated three additional months, beginning in October of the same year as the March IRP filing. Consequently, a significant part of the 2027 IRP's data and development discussion have occurred in parallel with the development of the 2025 IRP Update. While there are challenges in this overlap between the update and the next full IRP cycle, there are advantages as well.

Challenges of Overlapping IRPs and IRP Updates

- Managing two sets of developing data
- Clarifying which topics and assumptions are relevant to a specific stakeholder discussion
- Maintaining the integrity and fit-to-purpose of the Update:
    - As a check-point on the status of the prior preferred portfolio, featuring limited key updates and assumptions.
    - As an opportunity to update the status of any procurement activities and the IRP action plan.
    - As a progress report regarding acknowledgements.
    - As an indicator of where the next full IRP may be headed.

For the 2025 IRP Update, PacifiCorp has worked to maintain the integrity of the Update process, but has also capitalized on the public input timing overlap to provide an open public process including consultation from all interested parties, commissioners and commission staff, customers, and other stakeholders. In addition to the normal function of the open public input process to serve the next full IRP, this overlap has provided parties with a substantial opportunity to contribute information and feedback to the Update, receive responses to relevant questions, and inform all parties on the planning issues and approach. The public input process for this IRP Update is described in Chapter 2 (Introduction). Feedback received is primarily reflected in Appendix G (Stakeholder feedback forms).

Similar to a full IRP, this IRP Update maintains its core functions and provides an important milestone to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP Update preferred portfolio selection evaluates, over a twenty-year planning period[3], the future load of PacifiCorp customers and the resources required to meet this load.

[3] The starting year for charts and graphs relevant to an IRP Update reflects the passing of a year since the last full filing and consequently begin one year later. The Update does not roll the final year forward however, as this exercise requires obtaining a complete set of new data for an additional year, which is a labor-intensive exercise reserved for the full IRP. The next full IRP will likewise reflect that two years have "rolled off" of the prior study plan and will extend two more years into the future.

The IRP Update evaluates a broad range of available resource options to address any gaps created by changing loads and existing resources. This analysis also updates consideration of potential early retirement of existing coal and gas units on an economic basis. These resource options include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Chapters 6 through 9, includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of various risks, uncertainties and externality costs that could occur.

IRP Update Rules, Requirements and Guidelines

Consistent with the IRP standards and guidelines of Oregon, Utah, and Washington, PacifiCorp also includes Action Plan Status Update in Chapter 10 of this filing. The Action Plan Status Update provides a progress report on action items contained in the 2025 IRP. Given below are the IRP Update-specific requirements of each jurisdiction.

California

No new rules pertaining to the 2025 IRP Update.

Idaho

No new rules pertaining to the 2025 IRP Update.

Oregon

From Oregon rule OAR 860-027-0400(11):

(11) Each energy utility must submit an annual update on its most recently acknowledged IRP. The update is due on or before the acknowledgment order anniversary date. The energy utility must summarize the annual update at a Commission public meeting. The energy utility may request acknowledgment of changes, identified in its update, to the IRP action plan. The annual update is an informational filing that:
(a) Describes what actions the energy utility has taken to implement the action plan to select best portfolio of resources contained in its acknowledged IRP;
(b) Provides an assessment of what has changed since the acknowledgment order that affects the action plan to select best portfolio of resources, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and:
(c) Justifies any deviations from the action plan contained in its acknowledged IRP, or, where applicable, CEP.
(d) Includes an update that summarizes the utility's actions implementing the annual goals in the CEP filed with the most recently acknowledged IRP. The update will include, on an informational basis, an assessment of what has changed since the acknowledgment order that affects the utility's progress toward the clean energy targets in ORS 469A.410, reporting of measured impacts across the metrics that were presented in the most recently acknowledged CEP, and the electric company's two most

recent annual emissions reports filed with the Oregon Department of Environmental Quality under ORS 469A.420(4)(a).

Utah

No new rules pertaining to the 2025 IRP Update.

Washington

Washington follows a four-year IRP cycle, which differs from the other five states in PacifiCorp's territory. However, Washington also requires a Two-year Progress Report to be filed in the middle of each four-year cycle. Due to the shorter cycle of the other jurisdictions, PacifiCorp files a full IRP as Washington's Two-year Progress Report. In addition, PacifiCorp files an IRP Update during every year in between the full IRP and the Two-Year Progress Report. As of the 2025 IRP Update, all these filings enjoy a robust public input process leading to the distribution of the final document and relevant workpapers.

Wyoming

From Wyoming Administrative Rules Chapter 7, section 4(b):

4(b) The Commission may require an Affected Electric Utility to file updates to an IRP. Updates may include a detailed explanation of all changes to the Action Plan or any other information the Commission finds necessary.

Table B.1 – Integrated Resource Planning Standards and Guidelines Summary by State

B.1(a) IRP Guidelines - Source				
Oregon	**Utah**	**Washington**	**Idaho**	**Wyoming**
Order No. 07-002, *Investigation into Integrated Resource Planning*, January 8, 2007, as amended by Order No. 07-047. Order No. 08-339, *Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process*, June 30, 2008. Order No. 09-041, New Rule OAR 860-027-0400, implementing Guideline 3, "Plan Filing, Review, and Updates". Order No. 12-013, "Investigation of Matters related to Electric Vehicle Charging", January 19, 2012 Order No. 23-061, "Reconsideration of Order No. 22-390 Granted in Part; Reconsideration of Order Nos. 22-446 and 22-477 Denied, February 24, 2023.	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-620 *Content of an integrated resource plan. Filed 12/28/20, effective 12/31/20.* WAC 480-100-625 *Integrated resource plan development and timing. Filed 12/28/20, effective 12/31/20.* WAC 480-100-630 *Integrated resource planning advisory groups. Filed 12/28/20, effective 12/31/20.*	Order 22299 *Electric Utility Conservation Standards and Practices* January 1989.	Wyoming Electric, Gas and Water Utilities, Chapter 3, Section 33, March 21, 2016.

B.1(b) IRP Guidelines - Filing Requirements				
Oregon	**Utah**	**Washington**	**Idaho**	**Wyoming**
Least-cost plans must be filed with the Oregon PUC, including a Clean Energy Plan.	An IRP is to be submitted to commission.	Submit a least-cost plan to the WUTC every four years, including a Clean Energy Action Plan. Plan to be developed with consultation of WUTC staff, and with public involvement.	Submit Resource Management Report on planning status. Also, file progress reports on conservation, low-income programs, lost opportunities and capability building.	Each utility serving in Wyoming that files and IRP in another jurisdiction, shall file the IRP with the commission.

B.1(c) IRP Guidelines - Frequency				
Oregon	**Utah**	**Washington**	**Idaho**	**Wyoming**
Plans filed biennially, within two years of its previous IRP acknowledgment order. An annual update to the most recently acknowledged IRP is required to be filed on or before the one-year anniversary of the acknowledgment order date. While informational only, utilities may request acknowledgment of proposed changes to the action plan.	File biennially.	Unless otherwise ordered by the commission, each electric utility must file an integrated resource plan (IRP) with the commission by January 1, 2021, and every four years thereafter. At least every two years after the utility files its IRP, beginning January 1, 2023, the utility must file a two-year progress report.	RMR to be filed at least biennially. Conservation reports to be filed annually. Low income reports to be filed at least annually. Lost Opportunities reports to be filed at least annually. Capability building reports to be filed at least annually.	The commission may require any utility to file an IRP.

B.1(d) IRP Guidelines - Commission Response				
Oregon	**Utah**	**Washington**	**Idaho**	**Wyoming**
Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgment order is issued.	IRP acknowledged if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC no longer acknowledges IRPs.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying commission requirements.	Commission advisory staff reviews the IRP as directed by the Commission and drafts a memo to report its findings to the commission in an open meeting or technical conference.

B.1(e) IRP Guidelines - Process				
Oregon	**Utah**	**Washington**	**Idaho**	**Wyoming**
The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07- 002 requires that the utility present IRP results to the Oregon PUC at a public meeting prior to the deadline for written public comments. Commission staff and parties should complete their comments and recommendations within six months after IRP filing. Competitive secrets must be protected.	Planning process open to the public at all stages. IRP developed in consultation with the commission, its staff, with ample opportunity for public input.	In consultation with WUTC staff, develop and implement a public involvement plan. PacifiCorp is required to submit a work plan for informal commission review not later than 15 months prior to the due date of the plan. The utility must file its draft IRP with the commission four months prior to the filing of an IRP. (a) The commission will hear public comment on the draft IRP at an open meeting once filed. (b) The utility must file draft IRP presentation materials at least five business days prior to the open meeting.	Utilities to work with commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.	The review may be conducted in accordance with guidelines set from time to time as conditions warrant. The Public Service Commission of Wyoming, in its Letter Order on PacifiCorp's 2008 IRP (Docket No. 20000-346- EA-09) adopted commission Staff's recommendation to expand the review process to include a technical conference, an expanded public comment period, and filing of reply comments.

B.1(f) IRP Guidelines - Focus				
Oregon	**Utah**	**Washington**	**Idaho**	**Wyoming**
20-year plan, with end-effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs.	20-year plan, with short- term (four-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed. The IRP process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	20-year plan, which describes mix of resources sufficient to meet current and future loads and CETA standards at "lowest reasonable" cost. Resource cost, market volatility risks, demand-side resource uncertainty, resource dispatchability, ratepayer risks, policy impacts, environmental risks, and equitable distribution of benefits must be considered. Utilities must develop a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050.	20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility.	Identification of least-cost/least-risk resources and discussion of deviations from least-cost resources or resource combinations.

B.1(g) IRP Guidelines - Elements				
Oregon	**Utah**	**Washington**	**Idaho**	**Wyoming**
Basic elements include: • Consistent and comparable resource evaluation. • Risk and uncertainty must be considered. • Least cost planning, consistent with the long-run public interest. • Consistent with Oregon and federal energy policy. • External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). • Multi-state utilities should plan their generation and	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis. • Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds. • A cost effectiveness methodology. • An evaluation of the financial, competitive,	Basic elements: • A range of forecasts that examine the effect of economic forces on the consumption of electricity. • An assessment of conservation and load management, and policies and programs to achieve conservation. • Assessment of a wide range of generating technologies. • Assessment of transmission system capability and reliability. • Evaluation of energy supply resources (including transmission and distribution) using "lowest reasonable cost" criteria.	Discuss analyses considered including: • Load forecast uncertainties. • Changes to existing resources. • Equal consideration of demand and supply side resources. • Contingencies for upgrading, optioning and acquiring resources at optimum times. • Report on existing resource stack, load forecast and additional resource menu.	Commission IRP guidelines cover: • Sufficiency of the public comment process. • Utility strategic goals, resource planning goals and preferred resource portfolio. • Resource need over the near-term and long- term planning horizons. • Types of resources considered. • Changes in expected resource acquisitions and load growth from the previous IRP. • Environmental impacts considered.

B.1(g) IRP Guidelines - Elements				
Oregon	**Utah**	**Washington**	**Idaho**	**Wyoming**
transmission systems on an integrated-system basis. • Construction of resource portfolios over the range of identified risks and uncertainties. • Portfolio analysis shall include fuel transportation and transmission requirements. • Plan includes conservation potential study, demand response resources, environmental costs, and distributed generation technologies. • Avoided cost filing required within 30 days of acknowledgment. • IRP includes a description of the electric company's plan for meeting the requirements of the renewable portfolio standard.	reliability and operational risks associated with resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders	• Resource adequacy metrics. • Energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; health and environmental benefits, costs, and risks. • Long-range plan (10+ years). • Progress report compared to the previously filed plan. • Clean energy action plan for implementing RCW 19.405.030 through 19.405.050. • Summary of changes to modeling methodologies or inputs compared to the utility's previous IRP. • Analysis and summary of avoided costs; list of nonenergy costs and benefits and how they accrue. • Summary of public comments and utility responses.		• Market purchase evaluation. • Reserve margin analysis. • Demand-side management and conservation options.

Table B.2 – Handling of Relevant IRP Orders and Specific IRP Update Requirements

B.2(a) - Idaho		
Reference	**Requirement or Recommendation**	**2025 IRP Update Approach**
Order No. 35514 p. 17	…we encourage the Company to continue exploring an approach in its IRP process that allows for a reasonable and accurate selection of cost-effective natural gas resources in a portfolio.	Because of changing exogenous risks, new natural gas resources are included for selection in the 2025 IRP update.
Order No. 35514 p. 17	Finally, we acknowledge the inherent complexities with the Natrium project and direct the Company to continue to assess the risks of technology viability and potential delays with Natrium and plan accordingly.	In this cycle, Kemmerer (formerly "Natrium") is anticipated to come online in the fall of 2031 (modeled as 1/1/2032). Consistent with the 2023 IRP, the 2025 IRP Update includes variant analysis with no Kemmerer (formerly "Natrium") project as described in Chapters 8 and 9, designed to inform alternative path analysis and potential costs and benefits. PacifiCorp continues to evaluate nuclear resources within the context of an evolving planning environment.
Order 36868 p. 4	…before the next IRP, the Company provide the Commissions with: 1) the Company's re-evaluation study concerning the Boardman-to-Hemingway line...	For the 2025 IRP Update, B2H can serve new load in planning. Chapter 8 includes a sensitivity where B2H redirect rights are acquired from Bonneville Power Administration.
Order 36868 p. 4	Provide the Commission with…information regarding the removal of new large customer loads, customer plans to serve their own loads and the impact on the Company's system and Idaho customers	This Update advances the handling of large loads by including committed new large load in the preferred portfolio. The preferred portfolio includes optimized resource selection to serve this load. Aligned with stakeholder feedback, additional large-meter load studies are planned for the 2027 IRP based on forecasting that has not yet been developed. Please refer to Chapter 6, and to PacifiCorp's January 28-29 public input meeting for the 2027 IRP. January 28-29, 2026 Public Input Meeting
Order 36868 p. 4	…the Company provide an analysis demonstrating how its resources would change because of some of the most recent federal policies.	PacifiCorp has adjusted tax credits to align with current federal policy as a base assumption for new resources. Also, Chapter 8 includes a "Federal Tax Credits" sensitivity which assumes the resumption of IRA/IIJA tax credits in year 2030.

B.2(b) - Oregon		
Reference	**Requirement or Recommendation**	**2025 IRP Approach**
Order No. 24-073	In the 2025 IRP/CEP, direct PacifiCorp to update Natrium assumptions to reflect actual events.	For the 2025 IRP update, Kemmerer Unit 1(formerly Natrium) assumptions have been updated to the extent possible as described in Chapter 5 (Resource Options). The 2025 IRP Update includes variant analysis with no Kemmerer project as described in Chapters 8 and 9, designed to inform alternative path analysis and potential costs and benefits. PacifiCorp continues to evaluate nuclear resources within the context of an evolving planning environment.
Order No. 24-073	In the 2025 IRP/CEP model, PacifiCorp must: (1) demonstrate that simultaneous compliance with all state-level policies is feasible with the least-cost, least-risk Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP under multiple allocations.	In the 2025 IRP Update, each jurisdiction's resources are optimally selected in compliance with its unique requirements and then integrated into the preferred portfolio. This process begins with a system wide run selecting resources to meet a resource adequacy requirement. Existing resources are assumed to be allocated consistent with what is currently approved in each states' rates for cost-allocations. After this step, state requirements are considered and additional proxy resource selections are made with compliance in mind. As these selections are driven by a jurisdictions' specific need and obligations, they are assumed to be situs cost-allocated as consistent with existing allocation protocols. The process for ensuring the cost-effectiveness of the finished portfolio is described in detail in Chapter 6.
Order No. 24-073	In the 2025 IRP/CEP, PacifiCorp shall include an analysis of forecasted costs and annual emissions of the Preferred Portfolio using only actual carbon prices in effect in 2025 through the 20-year planning horizon.	In the 2025 IRP Update, this requirement continues to be met through the base assumptions of the medium gas price / no carbon price (MN) scenario. PacifiCorp also models other price-policy scenarios considering alternative carbon price futures. These studies are described in Chapter 7, 8, and 9.
Order No. 24-073	In the 2025 IRP/CEP, PacifiCorp shall confirm that coal generator cost assumptions reasonably reflect the structure and terms of any associated fuel supply agreements or fuel supply plans. Categorize variable costs that affect dispatch as variable costs in the model with as much accuracy as reasonably possible.	The 2025 IRP Update includes updated coal costs and assumptions leveraging the most current future cost and performance estimates available to the company. Any items which are based on generation (fuel, emissions, variable O&M etc.) have been confirmed with subject matter experts for accuracy.
Order No. 26-054 p.3	Additionally, we direct the company to include a scenario that allows the preferred portfolio, including resources sufficient for Oregon policies (HB 2021 and SB 1547), where the coal fleet is allowed to dispatch economically based on the marginal cost	As a base assumption in both the 2025 IRP and the 2025 IRP update, there is no zero cost fuel. From 2026-2029 only, Hunter/Huntington coal units are subject to a minimum take requirement that does not alter the cost of coal. After 2029, there are no minimum take requirements.

B.2(b) - Oregon		
Reference	**Requirement or Recommendation**	**2025 IRP Approach**
	of the fuel rather than zero cost for fuel delivered under the minimum take contract.	
Order No. 26-054 p.2	Present a resource acquisition plan that addresses system reliability as well as state specific needs and includes annual targets and important milestones.	The preferred portfolio development process integrates a system-wide reliable portfolio and incremental state specific needs as indicated in portfolios incorporating state laws and requirements. The resource selections in this portfolio are annual targets of resource types and amounts. Important milestones related to these decisions and targets can be found in Chapters 9 and 10, and in Appendix D.
Order No. 26-054 p.2	For HB 2021 compliance, provide a structured execution strategy with time-bound deliverables regarding procurement, allocation of existing resources, clean market purchase, and gas dispatch.	A discussion of the preferred portfolio execution strategy as relevant to Oregon and progress towards HB 2021 clean energy targets, pending the necessary ongoing conversations and negotiations, can be found in Appendix D – Oregon Clean Energy. In the planned OR June Supplemental filing, PacifiCorp will include additional narrative in fulfillment of Recommendations 2 and 10.
Order No. 26-054 p.3	Related to B2H, PacifiCorp must: File quarterly progress reports in Docket No. LC 85 on B2H that include a description of the proactive steps the company has taken and is planning to take to acquire BPA redirect rights	PacifiCorp has included an update related to acquiring redirect rights from BPA in Chapter 3. For the 2025 IRP Update, B2H can serve new load in planning. Chapter 8 includes a sensitivity where B2H redirect rights are acquired from Bonneville Power Administration.
Order No. 26-054 p.3	As part of its 2027 IRP and unless BPA redirect rights have already been acquired, provide analysis demonstrating the relative costs and risks of transmission investments with and without B2H redirects	Ahead of the 2027 IRP, a counterfactual sensitivity responsive to this directive is included in Chapter 8. The sensitivity assumes that redirect rights become available in 2028.
Order No. 26-054 p.4	In its 2025 IRP update, PacifiCorp should report on large-load interconnection requests received over the last five years and their current status (*e.g.*, in contract negotiations, energized etc.).	A table using aggregated data responsive to this directive is included in Chapter 6. This Update also advances the handling of large loads by including committed new large load in the preferred portfolio. The preferred portfolio includes optimized resource selection to serve this load.

B.2(b) - Oregon		
Reference	**Requirement or Recommendation**	**2025 IRP Approach**
		Aligned with stakeholder feedback, additional large-meter load studies are planned for the 2027 IRP based on forecasting that has not yet been developed. Please refer to Chapter 6, and to PacifiCorp's January 28-29 public input meeting for the 2027 IRP. January 28-29, 2026 Public Input Meeting
Order No. 26-054 p.5-6	We decline to adopt Staff's motion part 6, and instead direct Staff to bring a recommendation on whether the company has demonstrated continual progress towards meeting HB 2021 emissions goals to a future public meeting to allow consideration of the information direct in part 3a (Recommendations 2 and 10) to be filed in either the company's IRP Update or a separate filing before July 2026. We direct that this filing also include a discussion: • of what was procured in phase 1 of the 2025 RFP, • of the impact of EDAM on the use of unspecified market transactions and how to maximize the value of EDAM while maintaining HB 2021 compliance, and • that provides an update on PacifiCorp's investigation into the availability of clean market products to allow all parties to gain a better understanding of the options and limitations of products available in the market to meet both reliability and our clean energy goals.	As described in Appendix D – Oregon Clean Energy, in the planned OR June Supplemental filing, PacifiCorp will include narrative that addresses the direction in item 6, in addition to analysis and narrative in fulfillment of Recommendations 2 and 10.

B.2(c) - Utah		
Reference	**Requirement or Recommendation**	**2025 IRP Approach**
Docket No. 90-2035-01 p. 33-39	A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.	Chapters 7 and 8 include PacifiCorp presents its alternative path analysis in Chapter 9 of the 2025 IRP Update.

B.2(c) - Utah		
Reference	**Requirement or Recommendation**	**2025 IRP Approach**
Docket No. 90-2035-01 p. 33-39	An evaluation of the risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan.	PacifiCorp's 2025 IRP Update evaluates risk via risk-adjustment and energy not served metrics, including stochastic modeling results. The 2025 IRP Update will be considered in relevant business planning strategy dependent upon timing.

B.2(d) – Washington		
Reference	**Requirement or Recommendation**	**2025 IRP Update Approach**
WAC 480-100-625	PacifiCorp must file a two-year progress report in Washington. See the Washington section above for details about what must be included in the two-year progress report.	The IRP Update is not the Two-Year Progress Report, however the data that must be updated for the progress report is also updated for the IRP Update.

B.2(e) - Wyoming		
Reference	**Requirement or Recommendation**	**2025 IRP Approach**
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include an acknowledgement that each of these requirements are addressed in the 2025 IRP to ensure compliance.	PacifiCorp acknowledged that IRP requirements were met in the 2025 IRP, and that relevant requirements are met as applicable to the 2025 IRP Update.

APPENDIX C – SUPPLY-SIDE RESOURCE DETAILS

Introduction

This appendix provides details on new proxy resource options considered in PacifiCorp's 2025 IRP Update. Costs and characteristics of new proxy resources included in PacifiCorp's supply-side resource tables are based on National Laboratory of the Rockies's (NLR) 2024 Annual Technology Baseline (ATB), where appropriate. Costs are presented in 2025 dollars.

For the 2027 IRP, PacifiCorp is considering expanding the SSR table to include additional detail. Some of the additional detail PacifiCorp are considering include:

- Supply annual production limit (MW/year, or MWh/year for energy storage): the production capability that can be delivered to the market by factories.
- Production expansion rate: rate of increase to the "Supply annual production limit" based on available information about the construction of new factories and supply chains.
- Cost estimate accuracy range: high and low bounds of cost estimate accuracy.
- Escalation (or de-escalation) and economy-of-scale curves: the forecasted change in cost of technologies.
- CCS: apply new information from the on-going CCS FEED study.
- Proven-at-scale (MW & date): largest operational project and its commercial operation date.
- NLR ATB's Technology Innovation Scenarios: model Conservative, Moderate, and Advanced scenarios as sensitivities.

Table C.1 -- Supply-Side Resource Option Tables

	Characteristics and Costs	Operating Characteristics and Environmental Data
Thermal	Table C.2	Table C.4
Non-Thermal and Storage	Table C.3	Table C.5
	Additional Attributes and Fixed O&M	**Variable O&M, Total Cost and Credits**
Thermal	Table C.6	Table C.9
Non-Thermal	Table C.7	Table C.10
Storage	Table C.8	Table C.11

Supply-Side Table Column Headers:

Definitions for most column headers in Tables C.2-C.5 may be found in Table 7.12 "Glossary of Terms Used in the Supply-Side Resource Tables" of PacifiCorp's 2025 IRP. Additional details for column headers included in Tables C.6-C.11 are provided here:

- **Modeled IRP:** A "yes/no" indicator signaling whether a given resource option from the supply-side table was modeled in PLEXOS and available for selection.
- **Total Capital Cost ($/kW):** Total capital cost is equivalent to build cost.
- **Payment Factor (real levelized):** The real levelized payment factor, expressed as a percentage, is the real levelized capital carrying rate applied to capital cost to calculate the annual payment.
- **Annual Payment ($/kW-yr):** The annual payment required to recover the full present value of capital-related costs for a given resource over its economic life. Annual payment is calculated as the sum of total capital cost and demolition cost times the real levelized payment factor.
- **Gas Transport ($/kW-yr):** The fixed operation and maintenance costs associated with gas pipelines used to supply a gas generator.
- **Total Fixed O&M ($/kW-yr):** The sum of fixed operation and maintenance costs, capitalized fixed operation and maintenance costs and gas transportation costs, if applicable.
- **Total Fixed Cost ($/kW-yr):** The sum of total fixed O&M and annual payment.
- **Total Fixed Cost Converted ($/MWh):** A conversion of the total fixed cost in dollars per kilowatt-year to dollars per megawatt-hour. The total fixed cost in dollars per megawatt-hour also applies the assumed capacity factor for each resource option.
- **Levelized Fuel ($/MWh):** The cost of fuel used for electricity generation, converted from dollars per million metric British thermal units to dollars per megawatt-hour.
- **Total Resource Cost ($/MWh):** A sum of fixed costs, fuel costs and variable operations and maintenance costs (VOM) in dollars per megawatt-hour. Total resource cost is presented without tax credits applied for eligible resource options. For storage resources, fuel costs do not include the costs associated with charging storage resources.
- **Tax Credits ($/MWh) ITC Already Applied:** The value of production tax credits/investment tax credits expressed in dollars per megawatt-hour for applicable resources. For resources eligible for investment tax credits, the value of the credit is already captured in the payment factor.
- **Total Resource Cost with PTC/ITC Credits ($/MWh):** Total resource cost minus tax credits. For resources eligible for investment tax credits, this value is equivalent to the total resource cost without tax credits as the value of the investment tax credit is already captured in the payment factor.
- **Total Fixed Cost with Tax Credit ($/kW-yr):** Total fixed cost with tax credits applied. For resources eligible for investment tax credits, this value is equivalent to the total fixed cost without tax credits as the value of the investment tax credit is already captured in the payment factor.

Table C.2 – 2025 IRP Update Thermal Supply-Side Resources, Characteristics and Costs (2025$)

		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	7.0	2032	30	$2,131	$6.93	74%	91%	$42.82	3%	$14.59
Natural Gas	SCCT Aero, with SCR	0	50	2025	7.0	2032	40	$2,613	$7.40	87%	98%	$12.42	3%	$32.46
Natural Gas	SCCT Aero x4, with SCR	0	211	2025	7.0	2032	40	$1,789	$5.92	87%	98%	$9.93	3%	$32.46
Natural Gas	SCCT Frame "F" x1, with SCR	0	233	2025	7.0	2032	40	$1,319	$8.61	100%	99%	$30.64	3%	$12.13
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR	0	649	2025	8.0	2033	40	$1,762	$3.00	0%	100%	$46.53	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR	0	1,227	2025	8.0	2033	40	$1,477	$2.52	0%	100%	$38.67	0%	$11.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	0	565	2025	8.0	2033	+40	$3,286	$5.91	0%	100%	$84.48	0%	$65.28
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	0	1085	2025	8.0	2033	+40	$2,706	$5.34	0%	100%	$69.23	0%	$65.08
Natural Gas	Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	0	20	2025	7.0	2032	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	7.0	2032	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	7.0	2032	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	7.0	2032	40	$1,187	$7.75	100%	99%	$30.64	3%	$12.13
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	0	649	2025	8.0	2033	40	$1,586	$2.70	0%	100%	$46.53	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	0	1,227	2025	8.0	2033	40	$1,329	$2.27	0%	100%	$38.67	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	8.0	2033	40	$2,957	$5.32	0%	100%	$84.48	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	8.0	2033	40	$2,435	$4.81	0%	100%	$69.23	0%	$65.08
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	0	233	2025	7.0	2032	40	$1,517	$9.90	100%	99%	$30.64	3%	$13.95
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	0	649	2025	8.0	2033	40	$2,026	$3.46	0%	100%	$46.53	0%	$13.89
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	0	1,227	2025	8.0	2033	40	$1,698	$2.90	0%	100%	$38.67	0%	$13.67
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	233	2025	7.0	2032	40	$2,518	$9.04	100%	99%	$37.85	3%	$27.13
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	649	2025	8.0	2033	40	$2,961	$3.43	0%	100%	$53.73	0%	$27.08
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	0	1,227	2025	8.0	2033	40	$2,676	$2.95	0%	100%	$45.87	0%	$26.89
Hydrogen	SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	233	2025	7.0	2032	40	$2,030	$9.18	100%	99%	$43.50	3%	$27.13
Hydrogen	CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	649	2025	8.0	2033	40	$2,473	$3.58	0%	100%	$59.38	0%	$27.08
Hydrogen	CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	0	1,227	2025	8.0	2033	40	$2,188	$3.09	0%	100%	$51.52	0%	$26.89
Natural Gas	CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	0	649	2025	8.0	2033	+40	$1,755	$2.98	0%	100%	$45.30	0%	$12.08
Natural Gas	CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	0	1227	2025	8.0	2033	+40	$1,443	$2.47	0%	100%	$37.44	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	8.0	2033	+40	$3,124	$5.59	0%	100%	$79.58	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	8.0	2033	+40	$2,507	$4.97	0%	100%	$63.46	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	6.0	2031	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	$8,965	$3.44	0%	0%	$180.01	0%	$17.00
Nuclear	Small Modular Reactor or Advanced Reactor, Advanced Technology Case	N/A	600	2030	4.0	2034	60	$4,908	$2.85	0%	0%	$152.85	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	$9,861	$3.79	0%	0%	$198.01	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	$5,399	$3.13	0%	0%	$168.14	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	$12,565	$0.00	0%	0%	$207.48	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	$9,844	$0.00	0%	0%	$185.99	6%	$125.09

Table C.3 – 2025 IRP Update Non-thermal Supply-Side Resources, Characteristics and Costs (2025$)

		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)
Storage[1]	Li-Ion, 4-hour, 20 MW	N/A	20	2025	1.0	2026	20	$2,323	$0.00	0%	0%	$40.90	0%	$29.94
Storage[1]	Li-Ion, 4-hour, 200 MW	N/A	200	2025	2.0	2027	20	$1,741	$0.00	0%	0%	$40.40	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	$2,781	$0.00	0%	0%	$71.41	0%	$46.19
Storage[1]	Li-Ion, 4-hour, 1000 MW	N/A	1,000	2025	3.0	2028	20	$1,819	$0.00	0%	0%	$39.85	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	2028	2.0	2030	20	$2,769	$0.00	0%	0%	$25.00	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	$4,708	$0.69	0%	0%	$23.94	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	$4,004	$0.69	0%	0%	$23.94	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	$1,844	$0.00	0%	0%	$19.00	12%	$39.29
Solar	PV, 200 MW, Class 1-10	by location	200	2025	3.0	2028	25	$1,386	$0.00	0%	0%	$21.84	12%	$24.33
Solar	PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	by location	20	2025	3.0	2028	25	$1,720	$0.00	0%	0%	$18.03	12%	$37.33
Solar	PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	by location	200	2025	3.0	2028	25	$1,292	$0.00	0%	0%	$20.73	12%	$23.11
Wind	Wind Class 1-10, 20 MW	by location	20	2025	3.0	2028	30	$2,977	$0.00	0%	0%	$43.60	35%	$63.57
Wind	Wind Class 1-6, 200 MW	by location	200	2025	5.0	2030	30	$1,507	$0.00	0%	0%	$34.77	35%	$63.57
Wind	Wind Class 7, 200 MW	by location	200	2025	5.0	2030	30	$1,582	$0.00	0%	0%	$34.77	35%	$63.57
Wind	Offshore, Wind Class 12	0	200	2027	5.0	2032	30	$6,046	$0.00	0%	0%	$85.63	35%	$169.16
Wind	Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	by location	20	2025	3	2028	30	$2,837	$0.00	0%	0%	$39.20	35%	$60.58
Wind	Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	by location	200	2025	5	2030	30	$1,436	$0.00	0%	0%	$31.26	35%	$60.58
Wind	Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	by location	200	2025	5	2030	30	$1,508	$0.00	0%	0%	$31.26	35%	$60.58
Wind	Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	0	200	2027	5	2032	30	$4,357	$0.00	0%	0%	$78.15	35%	$121.92

[1] Assumed co-located

Table C.4 – 2025 IRP Update Thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2025$)

		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 + 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
clear	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
othermal	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 C.5 – 2025 IRP Update Non-thermal Supply-Side Resources, Operating Characteristics and Environmental Data (2025$)

		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 C.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 (real levelized)	Annual Payment ($/kW-Yr)	Capacity Factor	O&M ($/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	92.50%	$42.82	2.62%	$1.12	$0.00	$54.51	$202.34	$24.97
SCCT Aero, with SCR	No	0	$ 2,612.80	$ 32.46	6.101%	$161.39	33.00%	$12.42	2.62%	$0.32	$0.00	$15.81	$177.19	$61.30
SCCT Aero x4, with SCR	No	0	$ 1,789.35	$ 32.46	6.104%	$111.20	33.00%	$9.93	2.62%	$0.26	$0.00	$12.65	$123.85	$42.84
SCCT Frame "F" x1, with SCR	Yes	0	$ 1,319.06	$ 12.13	6.100%	$81.20	33.00%	$30.64	2.62%	$0.80	$0.00	$39.01	$120.22	$41.59
Goshen*	Yes	2,814	$ 1,332.25	$ 12.13	6.100%	$82.01	33.00%	$30.64	2.62%	$0.80	$96.20	$158.37	$240.37	$83.15
Wasatch Front	Yes	4,225	$ 1,305.87	$ 12.13	6.100%	$80.40	33.00%	$30.64	2.62%	$0.80	$14.72	$57.28	$137.68	$47.63
Wyoming East	Yes	6,130	$ 1,305.87	$ 12.13	6.100%	$80.40	33.00%	$30.64	2.62%	$0.80	$25.80	$71.02	$151.42	$52.38
CCCT Dry "H", 1X1, DF, with SCR	Yes	0	$ 1,762.06	$ 12.08	6.233%	$110.58	78.00%	$46.53	2.62%	$1.22	$0.00	$60.52	$171.11	$25.04
Goshen*	Yes	2,814	$ 1,779.68	$ 12.08	6.233%	$111.68	78.00%	$46.53	2.62%	$1.22	$60.34	$137.02	$248.70	$36.40
Wasatch Front	Yes	4,225	$ 1,744.44	$ 12.08	6.233%	$109.48	78.00%	$46.53	2.62%	$1.22	$9.25	$72.26	$181.74	$26.60
Wyoming East	Yes	6,130	$ 1,744.44	$ 12.08	6.233%	$109.48	78.00%	$46.53	2.62%	$1.22	$16.33	$81.22	$190.71	$27.91
CCCT Dry "H", 2X1, DF, with SCR	Yes	0	$ 1,476.70	$ 11.89	6.234%	$92.80	78.00%	$38.67	2.62%	$1.01	$0.00	$50.30	$143.10	$20.94
Goshen*	Yes	2,814	$ 1,491.47	$ 11.89	6.234%	$93.72	78.00%	$38.67	2.62%	$1.01	$61.16	$127.83	$221.55	$32.42
Wasatch Front	Yes	4,225	$ 1,461.94	$ 11.89	6.234%	$91.88	78.00%	$38.67	2.62%	$1.01	$9.38	$62.19	$154.07	$22.55
Wyoming East	Yes	6,130	$ 1,461.94	$ 11.89	6.234%	$91.88	78.00%	$38.67	2.62%	$1.01	$16.55	$71.28	$163.16	$23.88
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	No	0	$ 3,285.90	$ 65.28	6.239%	$209.08	78.00%	$84.48	5.54%	$4.68	$0.00	$113.03	$322.11	$47.14
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	No	0	$ 2,705.75	$ 65.08	6.241%	$172.93	78.00%	$69.23	5.54%	$3.84	$0.00	$92.63	$265.55	$38.86
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	No	0	$ 1,917.85	$ 14.59	6.891%	$133.16	33.00%	$42.82	2.62%	$1.12	$0.00	$54.51	$187.68	$64.92
SCCT Aero, with SCR + Δ for CT Brownfield construction	No	0	$ 2,351.52	$ 32.46	6.102%	$145.47	33.00%	$12.42	2.62%	$0.32	$0.00	$15.81	$161.28	$55.79
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	No	0	$ 1,610.42	$ 32.46	6.105%	$100.30	33.00%	$9.93	2.62%	$0.26	$0.00	$12.65	$112.94	$39.07
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	Yes	0	$ 1,187.16	$ 12.13	6.100%	$73.16	33.00%	$30.64	2.62%	$0.80	$0.00	$39.01	$112.17	$38.80
Goshen-Brownfield*	No	2,814	$ 1,199.03	$ 12.13	6.100%	$73.88	33.00%	$30.64	2.62%	$0.80	$96.20	$158.37	$232.25	$80.34
Wasatch Front-Brownfield	Yes	4,225	$ 1,175.28	$ 12.13	6.100%	$72.43	33.00%	$30.64	2.62%	$0.80	$14.72	$57.28	$129.72	$44.87
Wyoming East-Brownfield	Yes	6,130	$ 1,175.28	$ 12.13	6.100%	$72.43	33.00%	$30.64	2.62%	$0.80	$25.80	$71.02	$143.46	$49.62
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	Yes	0	$ 1,585.85	$ 12.08	6.234%	$99.62	78.00%	$46.53	2.62%	$1.22	$0.00	$60.52	$160.14	$23.44
Goshen-Brownfield*	No	2,814	$ 1,601.71	$ 12.08	6.234%	$100.60	78.00%	$46.53	2.62%	$1.22	$60.34	$137.02	$237.62	$34.78
Wasatch Front-Brownfield	Yes	4,225	$ 1,570.00	$ 12.08	6.234%	$98.63	78.00%	$46.53	2.62%	$1.22	$9.25	$72.26	$170.88	$25.01
Wyoming East-Brownfield	Yes	6,130	$ 1,570.00	$ 12.08	6.234%	$98.63	78.00%	$46.53	2.62%	$1.22	$16.33	$81.22	$179.85	$26.32
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	Yes	0	$ 1,329.03	$ 11.89	6.234%	$83.59	78.00%	$38.67	2.62%	$1.01	$0.00	$50.30	$133.89	$19.60
Goshen-Brownfield*	No	2,814	$ 1,342.32	$ 11.89	6.234%	$84.42	78.00%	$38.67	2.62%	$1.01	$61.16	$127.83	$212.25	$31.06
Wasatch Front-Brownfield	Yes	4,225	$ 1,315.74	$ 11.89	6.234%	$82.76	78.00%	$38.67	2.62%	$1.01	$9.38	$62.19	$144.95	$21.21
Wyoming East-Brownfield	Yes	6,130	$ 1,315.74	$ 11.89	6.234%	$82.76	78.00%	$38.67	2.62%	$1.01	$16.55	$71.28	$154.05	$22.54
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	No	0	$ 2,957.31	$ 65.28	6.240%	$188.61	78.00%	$84.48	5.54%	$4.68	$0.00	$113.03	$301.64	$44.15
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	No	0	$ 2,435.17	$ 65.08	6.242%	$156.07	78.00%	$69.23	5.54%	$3.84	$0.00	$92.63	$248.69	$36.40
SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 1,516.92	$ 13.95	5.605%	$85.81	33.00%	$30.64	2.62%	$0.80	$0.00	$39.01	$124.82	$43.18
CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 2,026.37	$ 13.89	5.604%	$114.34	78.00%	$46.53	2.62%	$1.22	$0.00	$60.52	$174.86	$25.59
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	No	0	$ 1,698.21	$ 13.67	5.604%	$95.93	78.00%	$38.67	2.62%	$1.01	$0.00	$50.30	$146.23	$21.40
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 2,518.07	$ 27.13	9.271%	$235.97	33.00%	$37.85	2.62%	$0.99	$0.00	$48.18	$284.15	$98.29
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 2,961.07	$ 27.08	9.254%	$276.52	78.00%	$53.73	2.62%	$1.41	$0.00	$69.89	$346.42	$50.70
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	No	0	$ 2,675.71	$ 26.89	9.263%	$250.34	78.00%	$45.87	2.62%	$1.20	$0.00	$59.67	$310.01	$45.37
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,029.98	$ 27.13	9.255%	$190.39	33.00%	$43.50	2.62%	$1.14	$0.00	$55.38	$245.77	$85.02
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,472.98	$ 27.08	9.245%	$231.13	78.00%	$59.38	2.62%	$1.55	$0.00	$77.25	$308.38	$45.13
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	No	0	$ 2,187.62	$ 26.89	9.250%	$204.84	78.00%	$51.52	2.62%	$1.35	$0.00	$67.02	$271.87	$39.79
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	No	0	$ 1,755.00	$ 12.08	6.233%	$110.14	78.00%	$45.30	2.62%	$1.19	$0.00	$58.93	$169.07	$24.74
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	No	0	$ 1,443.04	$ 11.89	6.234%	$90.70	78.00%	$37.44	2.62%	$0.98	$0.00	$48.70	$139.40	$20.40
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS	No	0	$ 3,124.46	$ 65.28	6.233%	$198.82	78.00%	$79.58	5.54%	$4.41	$0.00	$106.48	$305.30	$44.68
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS	No	0	$ 2,507.15	$ 65.08	6.234%	$160.35	78.00%	$63.46	5.54%	$3.52	$0.00	$84.91	$245.26	$35.89
Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer	Yes	0	$ 2,858.50	$ 44.94	4.170%	$121.07	98.00%	$60.95	0.00%	$0.00	$0.00	$77.27	$198.35	$23.10
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	No	0	$ 560.99	$ 32.46	4.170%	$24.75	97.00%	$10.28	0.00%	$0.00	$0.00	$12.22	$36.96	$4.35
Δ CCS Dave Johnston 4 (costs on post retrofit basis)	No	5,541	$ 3,500.78	$ 53.20	6.447%	$229.12	85.00%	$277.68	5.54%	$15.38	$0.00	$363.59	$592.72	$79.60
Δ CCS Hunter 1-3 (costs on post retrofit basis)	No	6,429	$ 2,951.20	$ 53.20	6.451%	$193.81	85.00%	$235.36	5.54%	$13.04	$0.00	$308.18	$501.99	$67.42
Δ CCS Huntington 1&2 (costs on post retrofit basis)	No	6,933	$ 2,951.40	$ 53.20	6.451%	$193.83	85.00%	$242.12	5.54%	$13.41	$0.00	$317.03	$510.86	$68.61
Δ CCS Jim Bridger 3&4 (costs on post retrofit basis)	Yes	7,513	$ 2,598.38	$ 53.20	6.454%	$171.13	85.00%	$254.91	5.54%	$14.12	$0.00	$326.66	$497.79	$66.85
Δ CCS Wyodak (costs on post retrofit basis)	No	4,448	$ 3,504.25	$ 53.20	6.447%	$229.35	85.00%	$309.51	5.54%	$17.15	$0.00	$405.27	$634.62	$85.23
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	Yes	N/A	$ 8,964.66	$ 17.00	5.042%	$452.86	93.00%	$180.01	9.42%	$16.96	$0.00	$260.71	$713.57	$87.59
Goshen	Yes	2,814	$ 9,143.96	$ 17.00	5.042%	$461.90	93.00%	$180.01	9.42%	$16.96	$0.00	$260.71	$722.61	$88.70
Wasatch Front	Yes	4,225	$ 9,143.96	$ 17.00	5.042%	$461.90	93.00%	$180.01	9.42%	$16.96	$0.00	$260.71	$722.61	$88.70
Wyoming East	Yes	6,130	$ 8,875.02	$ 17.00	5.042%	$448.34	93.00%	$180.01	9.42%	$16.96	$0.00	$260.71	$709.05	$87.03
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	No	N/A	$ 4,908.02	$ 12.00	5.042%	$248.07	93.00%	$152.85	9.42%	$14.41	$0.00	$216.66	$464.73	$57.04
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	No	N/A	$ 9,861.13	$ 17.00	5.042%	$498.06	93.00%	$198.01	9.42%	$18.66	$0.00	$286.79	$784.84	$96.34
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	No	N/A	$ 5,398.82	$ 12.00	5.042%	$272.81	93.00%	$168.14	9.42%	$15.85	$0.00	$238.33	$511.14	$62.74
Large Light Water Reactor, Moderate Technology Case	No	N/A	$ 7,562.87	$ 10.00	5.042%	$381.82	93.00%	$125.36	9.42%	$11.81	$0.00	$189.56	$571.38	$70.14
Large Light Water Reactor, Advanced Technology Case	No	N/A	$ 6,265.25	$ 9.00	5.042%	$316.35	93.00%	$90.26	9.42%	$8.51	$0.00	$130.72	$447.07	$54.88
Near Field Enhanhanced Geothermal System (NF-EGS) Binary	Yes	N/A	$ 12,565.49	$ 125.09	6.262%	$794.68	80.00%	$207.48	0.87%	$1.81	$0.00	$238.20	$1,032.89	$147.39
Southern OR	Yes	497	$ 14,701.62	$ 125.09	6.262%	$928.45	80.00%	$207.48	0.87%	$1.81	$0.00	$238.20	$1,166.65	$166.47
Wasatch Front	Yes	4,225	$ 12,565.49	$ 125.09	6.262%	$794.68	80.00%	$207.48	0.87%	$1.81	$0.00	$238.20	$1,032.89	$147.39
Near Field Enhanhanced Geothermal System (NF-EGS) Binary Low Cost	Yes	N/A	$ 9,045.13	$ 125.09	6.262%	$574.24	80.00%	$207.48	0.87%	$1.81	$0.00	$238.20	$812.44	$115.93

* Δ for CCS installation on existing coal units is for CCS costs and operating characterisitics only, not the operation of the existing coal resource.

Table C.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 (real levelized)	Annual Payment ($/kW-Yr)	Capacity Factor	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)
PV, 20 MW, Class 1-10	Yes	by location	$ 1,843.89	$ 39.29	6.861%	$129.21	27.33%	$19.00	1.37%	$0.26	$21.92	$151.12
Portland North Coast	Yes	19	$ 1,954.52	$ 39.29	6.861%	$136.80	24.49%	$19.00	1.37%	$0.26	$21.92	$158.71
Southern OR	Yes	497	$ 2,046.72	$ 39.29	6.861%	$143.12	29.29%	$19.00	1.37%	$0.26	$21.92	$165.04
Walla Walla	Yes	2,353	$ 1,880.77	$ 39.29	6.861%	$131.74	25.96%	$19.00	1.37%	$0.26	$21.92	$153.65
Goshen	Yes	2,814	$ 1,862.33	$ 39.29	6.861%	$130.47	27.79%	$19.00	1.37%	$0.26	$21.92	$152.39
Wasatch Front	Yes	4,225	$ 1,843.89	$ 39.29	6.861%	$129.21	29.00%	$19.00	1.37%	$0.26	$21.92	$151.12
Wyoming East	Yes	6,130	$ 1,843.89	$ 39.29	6.861%	$129.21	27.47%	$19.00	1.37%	$0.26	$21.92	$151.12
PV, 200 MW, Class 1-10	Yes	by location	$ 1,385.53	$ 24.33	6.861%	$96.73	27.33%	$21.84	1.37%	$0.30	$25.20	$121.93
Portland North Coast	Yes	19	$ 1,468.66	$ 24.33	6.861%	$102.43	24.49%	$21.84	1.37%	$0.30	$25.20	$127.63
Southern OR	Yes	497	$ 1,537.93	$ 24.33	6.861%	$107.19	29.29%	$21.84	1.37%	$0.30	$25.20	$132.38
Walla Walla	Yes	2,353	$ 1,413.24	$ 24.33	6.861%	$98.63	25.96%	$21.84	1.37%	$0.30	$25.20	$123.83
Goshen	Yes	2,814	$ 1,399.38	$ 24.33	6.861%	$97.68	27.79%	$21.84	1.37%	$0.30	$25.20	$122.88
Wasatch Front	Yes	4,225	$ 1,385.53	$ 24.33	6.861%	$96.73	29.00%	$21.84	1.37%	$0.30	$25.20	$121.93
Wyoming East	Yes	6,130	$ 1,385.53	$ 24.33	6.861%	$96.73	27.47%	$21.84	1.37%	$0.30	$25.20	$121.93
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	by location	$ 1,719.61	$ 37.33	6.862%	$120.56	27.33%	$18.03	1.37%	$0.25	$20.80	$141.36
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	No	by location	$ 1,292.14	$ 23.11	6.862%	$90.25	27.33%	$20.73	1.37%	$0.28	$23.92	$114.17
Wind Class 1-10, 20 MW	Yes	by location	$ 2,977.21	$ 63.57	6.292%	$191.33	29.20%	$43.60	4.39%	$1.91	$51.80	$243.13
Portland North Coast	Yes	19	$ 3,304.70	$ 63.57	6.292%	$211.93	24.91%	$43.60	4.39%	$1.91	$51.80	$263.74
Southern OR	Yes	497	$ 3,513.11	$ 63.57	6.292%	$225.04	25.18%	$43.60	4.39%	$1.91	$51.80	$276.85
Walla Walla	Yes	2,353	$ 3,096.30	$ 63.57	6.292%	$198.82	23.13%	$43.60	4.39%	$1.91	$51.80	$250.62
Goshen	Yes	2,814	$ 3,036.75	$ 63.57	6.292%	$195.07	30.28%	$43.60	4.39%	$1.91	$51.80	$246.88
Wasatch Front	Yes	4,225	$ 3,006.98	$ 63.57	6.292%	$193.20	30.42%	$43.60	4.39%	$1.91	$51.80	$245.00
Wyoming East	Yes	6,130	$ 2,917.67	$ 63.57	6.292%	$187.58	41.25%	$43.60	4.39%	$1.91	$51.80	$239.38
Wind Class 1-6, 200 MW	Yes	by location	$ 1,507.21	$ 63.57	6.316%	$99.21	34.13%	$34.77	4.39%	$1.53	$43.14	$142.35
Portland North Coast	Yes	19	$ 1,673.01	$ 63.57	6.316%	$109.68	37.62%	$34.77	4.39%	$1.53	$43.14	$152.82
Southern OR	Yes	497	$ 1,778.51	$ 63.57	6.316%	$116.35	34.06%	$34.77	4.39%	$1.53	$43.14	$159.48
Walla Walla	Yes	2,353	$ 1,567.50	$ 63.57	6.316%	$103.02	32.59%	$34.77	4.39%	$1.53	$43.14	$146.16
Goshen	Yes	2,814	$ 1,537.36	$ 63.57	6.316%	$101.11	30.28%	$34.77	4.39%	$1.53	$43.14	$144.25
Wasatch Front	Yes	4,225	$ 1,522.29	$ 63.57	6.316%	$100.16	30.42%	$34.77	4.39%	$1.53	$43.14	$143.30
Wyoming East	Yes	6,130	$ 1,477.07	$ 63.57	6.316%	$97.31	39.80%	$34.77	4.39%	$1.53	$43.14	$140.44
Wind Class 7, 200 MW	No	by location	$ 1,582.34	$ 63.57	6.313%	$103.91	34.37%	$34.77	4.39%	$1.53	$43.14	$147.04
Offshore, Wind Class 12	Yes	0	$ 6,046.02	$ 169.16	5.202%	$323.31	31.02%	$85.63	4.39%	$3.76	$110.90	$434.22
Southern OR	Yes	497	$ 7,134.31	$ 169.16	5.202%	$379.93	48.94%	$85.63	4.39%	$3.76	$110.90	$490.83
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 2,836.98	$ 60.58	6.292%	$182.31	29.20%	$39.20	4.39%	$1.72	$46.57	$228.89
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 1,436.22	$ 60.58	6.316%	$94.54	34.37%	$31.26	4.39%	$1.37	$38.78	$133.32
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	No	by location	$ 1,507.82	$ 60.58	6.313%	$99.01	34.37%	$31.26	4.39%	$1.37	$38.78	$137.79
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	No	0	$ 4,357.37	$ 121.92	4.841%	$216.84	84.43%	$78.15	4.39%	$3.43	$101.22	$318.06

Table C.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 (real levelized)	Annual Payment ($/kW-Yr)	Capacity Factor	Storage Efficiency	O&M ($/kW-Yr)	Capitalized Premium	O&M Capitalized ($/kW-Yr)	Total Fixed O&M ($/kW-Yr)	Total Fixed Cost ($/kW-Yr)	Total Fixed Cost Converted ($/MWh)
Li-Ion, 4-hour, 20 MW[1]	No	N/A	$ 2,323.15	$ 29.94	5.354%	$125.98	16.67%	85%	$40.90	0.00%	$ -	$44.59	$170.57	$116.83
Li-Ion, 4-hour, 200 MW[1]	Yes	N/A	$ 1,740.79	$ 25.66	5.354%	$94.58	16.67%	85%	$40.40	0.00%	$0.00	$45.00	$139.57	$95.60
Portland North Coast	Yes	19	$ 1,845.24	$ 25.66	5.354%	$100.17	16.67%	85%	$40.40	0.00%	$0.00	$45.00	$145.16	$99.43
Southern OR	Yes	497	$ 1,880.06	$ 25.66	5.354%	$102.03	16.67%	85%	$40.40	0.00%	$0.00	$45.00	$147.03	$100.70
Walla Walla	Yes	2,353	$ 1,793.02	$ 25.66	5.354%	$97.37	16.67%	85%	$40.40	0.00%	$0.00	$45.00	$142.37	$97.51
Goshen	Yes	2,814	$ 1,775.61	$ 25.66	5.354%	$96.44	16.67%	85%	$40.40	0.00%	$0.00	$45.00	$141.44	$96.87
Wasatch Front	Yes	4,225	$ 1,793.02	$ 25.66	4.452%	$80.97	16.67%	85%	$40.40	0.00%	$0.00	$45.00	$125.96	$86.28
Wyoming East	Yes	6,130	$ 1,723.39	$ 25.66	4.452%	$77.87	16.67%	85%	$40.40	0.00%	$0.00	$45.00	$122.86	$84.15
Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW[1]	Yes	N/A	$ 2,780.73	$ 46.19	5.355%	$151.38	33.33%	85%	$71.41	0.00%	$0.00	$79.54	$230.92	$79.08
Portland North Coast	Yes	19	$ 2,947.58	$ 46.19	5.355%	$160.32	33.33%	85%	$71.41	0.00%	$0.00	$79.54	$239.86	$82.14
Southern OR	Yes	497	$ 3,003.19	$ 46.19	5.355%	$163.29	33.33%	85%	$71.41	0.00%	$0.00	$79.54	$242.84	$83.16
Walla Walla	Yes	2,353	$ 2,864.16	$ 46.19	5.355%	$155.85	33.33%	85%	$71.41	0.00%	$0.00	$79.54	$235.39	$80.61
Goshen	Yes	2,814	$ 2,836.35	$ 46.19	5.355%	$154.36	33.33%	85%	$71.41	0.00%	$0.00	$79.54	$233.90	$80.10
Wasatch Front	Yes	4,225	$ 2,864.16	$ 46.19	4.453%	$129.60	33.33%	85%	$71.41	0.00%	$0.00	$79.54	$209.14	$71.62
Wyoming East	Yes	6,130	$ 2,752.93	$ 46.19	4.453%	$124.64	33.33%	85%	$71.41	0.00%	$0.00	$79.54	$204.19	$69.93
Li-Ion, 4-hour, 1000 MW[1]	No	N/A	$ 1,818.53	$ 25.66	5.356%	$98.77	16.67%	85%	$39.85	0.00%	$0.00	$45.35	$144.13	$98.72
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	$57.49	$116.43	$79.74
Wasatch Front	Yes	4,225	$ 2,081.62	$ 0.19	2.916%	$60.71	16.67%	83%	$50.51	0.00%	$0.00	$57.49	$118.20	$80.96
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	$109.15	$196.83	$67.41
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	$21.85	$184.94	$63.34
100-hour Iron Air	Yes	N/A	$ 2,769.07	$ 171.06	4.581%	$134.69	30.07%	43%	$25.00	2.62%	$0.65	$30.49	$165.17	$62.71
Portland North Coast	Yes	19	$ 2,935.21	$ 171.06	5.484%	$170.35	30.07%	43%	$25.00	2.62%	$0.65	$30.49	$200.84	$76.24
Wasatch Front	Yes	4,225	$ 2,852.14	$ 171.06	4.581%	$138.49	30.07%	43%	$25.00	2.62%	$0.65	$30.49	$168.98	$64.15
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	$24.63	$122.43	$83.85
Pumped Hydro, Two New Reservoirs, 10-hour	Yes	N/A	$ 4,708.34	$ 207.95	3.121%	$153.44	41.67%	80%	$23.94	2.62%	$0.63	$29.20	$182.63	$50.04
Portland North Coast	Yes	19	$ 4,990.84	$ 207.95	3.121%	$162.25	41.67%	80%	$23.94	2.62%	$0.63	$29.20	$191.45	$52.45
Southern OR	Yes	497	$ 5,085.01	$ 207.95	3.121%	$165.19	41.67%	80%	$23.94	2.62%	$0.63	$29.20	$194.39	$53.26
Goshen	Yes	2,814	$ 4,802.51	$ 207.95	3.121%	$156.38	41.67%	80%	$23.94	2.62%	$0.63	$29.20	$185.57	$50.84
Wasatch Front	Yes	4,225	$ 4,849.59	$ 207.95	2.582%	$130.59	41.67%	80%	$23.94	2.62%	$0.63	$29.20	$159.78	$43.78
Wyoming East	Yes	6,130	$ 4,661.26	$ 207.95	2.582%	$125.72	41.67%	80%	$23.94	2.62%	$0.63	$29.20	$154.92	$42.44
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	$24.63	$119.12	$81.59
Pumped Hydro, One New Reservoir, 10-hour	No	N/A	$ 4,004.36	$ 176.87	3.121%	$130.50	41.67%	80%	$23.94	2.62%	$0.63	$29.20	$159.69	$43.75
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	$2.49	$212.01	$68.21
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	$1.23	$390.72	$125.70

[1]Assumed co-located

Table C.9 – 2025 IRP Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits

Resource Description	Variable O&M				Total Resource Cost ($/MWh)	Credits		
	Levelized Fuel ($/MWh)	O&M ($/MWh)	Capitalized Premium	O&M Capitalized ($/MWh)		Tax Credits ($/MWh) (ITC already applied)	Total Resource Cost with PTC / ITC Credits ($/MWh)	Total Fixed Cost with Tax Credit ($/kW-yr)
Internal Combustion Engine, renewable biofuel, with SCR & 24-hour fuel tank	$ 357.85	$6.93	14.39%	$1.00	$390.74	$ -	$390.74	$202.34
SCCT Aero, with SCR	$ 53.04	$7.40	14.39%	$1.07	$122.81	$ -	$122.81	$177.19
SCCT Aero x4, with SCR	$ 53.04	$5.92	14.39%	$0.85	$102.66	$ -	$102.66	$123.85
SCCT Frame "F" x1, with SCR	$ 54.56	$8.61	14.39%	$1.24	$105.99	$ -	$105.99	$120.22
Goshen	$ 55.25	$8.61	14.39%	$1.24	$148.25	$ -	$148.25	$240.37
Wasatch Front	$ 55.27	$8.61	14.39%	$1.24	$112.75	$ -	$112.75	$137.68
Wyoming East	$ 47.47	$8.61	14.39%	$1.24	$109.70	$ -	$109.70	$151.42
CCCT Dry "H", 1X1, DF, with SCR	$ 33.91	$3.00	14.39%	$0.43	$62.39	$ -	$62.39	$171.11
Goshen	$ 34.65	$3.00	14.39%	$0.43	$74.49	$ -	$74.49	$248.70
Wasatch Front	$ 34.74	$3.00	14.39%	$0.43	$64.77	$ -	$64.77	$181.74
Wyoming East	$ 30.05	$3.00	14.39%	$0.43	$61.39	$ -	$61.39	$190.71
CCCT Dry "H", 2X1, DF, with SCR	$ 34.37	$2.52	14.39%	$0.36	$58.20	$ -	$58.20	$143.10
Goshen	$ 35.12	$2.52	14.39%	$0.36	$70.43	$ -	$70.43	$221.55
Wasatch Front	$ 35.21	$2.52	14.39%	$0.36	$60.64	$ -	$60.64	$154.07
Wyoming East	$ 30.45	$2.52	14.39%	$0.36	$57.22	$ -	$57.22	$163.16
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1	$ 37.86	$5.91	11.52%	$0.68	$91.59	$ -	$91.59	$322.11
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1	$ 38.42	$5.34	11.52%	$0.62	$83.24	$ -	$83.24	$265.55
Internal Combustion Engine, renewable biofuel, with SCR + Δ for CT Brownfield construction	$ 46.57	$6.24	14.39%	$0.90	$118.63	$ -	$118.63	$187.68
SCCT Aero, with SCR + Δ for CT Brownfield construction	$ 53.04	$6.66	14.39%	$0.96	$116.45	$ -	$116.45	$161.28
SCCT Aero x4, with SCR + Δ for CT Brownfield construction	$ 53.04	$5.33	14.39%	$0.77	$98.21	$ -	$98.21	$112.94
SCCT Frame "F" x1, with SCR + Δ for CT Brownfield construction	$ 54.56	$7.75	14.39%	$1.12	$102.23	$ -	$102.23	$112.17
Goshen-Brownfield	$ 54.23	$7.75	14.39%	$1.12	$143.44	$ -	$143.44	$232.25
Wasatch Front-Brownfield	$ 54.29	$7.75	14.39%	$1.12	$108.02	$ -	$108.02	$129.72
Wyoming East-Brownfield	$ 53.90	$7.75	14.39%	$1.12	$112.39	$ -	$112.39	$143.46
CCCT Dry "H", 1X1, DF, with SCR + Δ for CT Brownfield construction	$ 33.91	$2.70	14.39%	$0.39	$60.44	$ -	$60.44	$160.14
Goshen-Brownfield	$ 34.01	$2.70	14.39%	$0.39	$71.88	$ -	$71.88	$237.62
Wasatch Front-Brownfield	$ 34.12	$2.70	14.39%	$0.39	$62.22	$ -	$62.22	$170.88
Wyoming East-Brownfield	$ 34.12	$2.70	14.39%	$0.39	$63.53	$ -	$63.53	$179.85
CCCT Dry "H", 2X1, DF, with SCR + Δ for CT Brownfield construction	$ 34.37	$2.27	14.39%	$0.33	$56.57	$ -	$56.57	$133.89
Goshen-Brownfield	$ 34.48	$2.27	14.39%	$0.33	$68.14	$ -	$68.14	$212.25
Wasatch Front-Brownfield	$ 34.58	$2.27	14.39%	$0.33	$58.39	$ -	$58.39	$144.95
Wyoming East-Brownfield	$ 34.58	$2.27	14.39%	$0.33	$59.72	$ -	$59.72	$154.05
CCCT Dry "H", 1X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 1x1 + Δ for CT Brownfield construction	$ 37.86	$5.32	11.52%	$0.61	$87.94	$ -	$87.94	$301.64
CCCT Dry "H", 2X1, DF, with SCR + Δ for adding 95% CCS to new CCCT 2x1 + Δ for CT Brownfield construction	$ 38.42	$4.81	11.52%	$0.55	$80.18	$ -	$80.18	$248.69
SCCT Frame "F" x1, with SCR + Δ for 100%Hydrogen burning capability	$ 54.56	$9.90	14.39%	$1.42	$109.06	$ -	$109.06	$124.82
CCCT Dry "H", 1X1, DF, with SCR + Δ for 100%Hydrogen burning capability	$ 33.91	$3.46	14.39%	$0.50	$63.46	$ -	$63.46	$174.86
CCCT Dry "H", 2X1, DF, with SCR + Δ for 100%Hydrogen burning capability	$ 34.37	$2.90	14.39%	$0.42	$59.09	$ -	$59.09	$146.23
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 54.56	$9.04	14.39%	$1.30	$163.19	$ -	$163.19	$284.15
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 33.91	$3.43	14.39%	$0.49	$88.54	$ -	$88.54	$346.42
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, cavern, 80 bar, 24 hour	$ 34.37	$2.95	14.39%	$0.42	$83.12	$ -	$83.12	$310.01
SCCT Frame "F" x1, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 54.56	$9.18	14.39%	$1.32	$150.08	$ -	$150.08	$245.77
CCCT Dry "H", 1X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 33.91	$3.58	14.39%	$0.51	$83.14	$ -	$83.14	$308.38
CCCT Dry "H", 2X1, DF, with SCR + Δ for Hydrogen storage, tanks, 500 bar, 24 hour	$ 34.37	$3.09	14.39%	$0.45	$77.70	$ -	$77.70	$271.87
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1	$ 33.91	$2.98	14.39%	$0.43	$62.07	$ -	$62.07	$169.07
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1	$ 34.37	$2.47	14.39%	$0.36	$57.60	$ -	$57.60	$139.40
CCCT Dry "H", 1X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 1x1, 95% CCS	$ 37.86	$5.59	11.52%	$0.64	$88.77	$ -	$88.77	$305.30
CCCT Dry "H", 2X1, DF, with SCR, Advanced Technology Case + Δ advanced technology case, CCCT 2x1, 95% CCS	$ 38.42	$4.97	11.52%	$0.57	$79.86	$ -	$79.86	$245.26
Hydrogen peaker with CCCT Dry "H", 2X1, DF and electrolyzer	$ -	$0.00	0.00%	$0.00	$23.10	$ (4.85)	$23.10	$198.35
Electrolyzer, Proton Exchange Membrane (PEM), 50,000 kg/day	$ -	$23.91	0.00%	$0.00	$28.26	$ (0.96)	$28.26	$36.96
CCS Dave Johnston 4 (costs on post retrofit basis)	$ -	$11.40	11.52%	$1.31	$92.31	$ -	$ 92.31	$ 592.72
CCS Hunter 1-3 (costs on post retrofit basis)	$ -	$9.73	11.52%	$1.12	$78.27	$ -	$ 78.27	$ 501.99
CCS Huntington 1&2 (costs on post retrofit basis)	$ -	$9.63	11.52%	$1.11	$79.35	$ -	$ 79.35	$ 510.86
CCS Jim Bridger 3&4 (costs on post retrofit basis)	$ -	$10.57	11.52%	$1.22	$78.64	$ -	$ 78.64	$ 497.79
CCS Wyodak (costs on post retrofit basis)	$ -	$11.69	11.52%	$1.35	$98.26	$ -	$ 98.26	$ 634.62
Small Modular Reactor or Advanced Reactor, Moderate Technology Case	$ -	$3.44	0.00%	$0.00	$91.03	$ -	$91.03	$713.57
Goshen	$ -	$3.44	0.00%	$0.00	$92.14	$ -	$92.14	$722.61
Wasatch Front	$ -	$3.44	0.00%	$0.00	$92.14	$ -	$92.14	$722.61
Wyoming East	$ -	$3.44	0.00%	$0.00	$90.48	$ -	$90.48	$709.05
Small Modular Reactor or Advanced Reactor, Advanced Technology Case	$ -	$2.85	0.00%	$0.00	$59.89	$ -	$59.89	$464.73
Small Modular Reactor or Advanced Reactor, Moderate Technology Case + Δ for nuclear integrated thermal storage	$ -	$3.79	0.00%	$0.00	$100.12	$ -	$100.12	$784.84
Small Modular Reactor or Advanced Reactor, Advanced Technology Case + Δ for nuclear integrated thermal storage	$ -	$3.13	0.00%	$0.00	$65.88	$ -	$65.88	$511.14
Large Light Water Reactor, Moderate Technology Case	$ -	$9.38	0.00%	$0.00	$79.52	$ -	$79.52	$571.38
Large Light Water Reactor, Advanced Technology Case	$ -	$7.88	0.00%	$0.00	$62.76	$ -	$62.76	$447.07
Near Field Enhanhanced Geothermal System (NF-EGS) Binary	$ -	$0.00	0.00%	$0.00	$147.39	$ -	$147.39	$1,032.89
Southern OR	$ -	$0.00	0.00%	$0.00	$166.47	$ -	$166.47	$1,166.65
Wasatch Front	$ -	$0.00	0.00%	$0.00	$147.39	$ -	$147.39	$1,032.89
Wasatch Front	$ -	$0.00	0.00%	$0.00	$115.93	$ -	$115.93	$812.44

* Δ for CCS installation on existing coal units is for CCS costs and operating characterisitics only, not the operation of the existing coal resource.

Table C.10 – 2025 IRP Non-Thermal Supply-Side Resources, Variable O&M, Total Cost and Credits

Resource Description	Total Resource Cost ($/MWh)	Credits		
		Tax Credits ($/MWh) (ITC already applied)	Total Resource Cost with PTC / ITC Credits ($/MWh)	Total Fixed Cost with Tax Credit ($/kW-yr)
PV, 20 MW, Class 1-10	$63.12	$ -	$63.12	$151.12
Portland North Coast	$73.99	$ -	$73.99	$158.71
Southern OR	$64.32	$ -	$64.32	$165.04
Walla Walla	$67.57	$ -	$67.57	$153.65
Goshen	$62.60	$ -	$62.60	$152.39
Wasatch Front	$59.50	$ -	$59.50	$151.12
Wyoming East	$62.80	$ -	$62.80	$151.12
PV, 200 MW, Class 1-10	$50.92	$ -	$50.92	$121.93
Portland North Coast	$59.50	$ -	$59.50	$127.63
Southern OR	$51.60	$ -	$51.60	$132.38
Walla Walla	$54.45	$ -	$54.45	$123.83
Goshen	$50.47	$ -	$50.47	$122.88
Wasatch Front	$48.00	$ -	$48.00	$121.93
Wyoming East	$50.67	$ -	$50.67	$121.93
PV, 20 MW, Class 1-10 + Δ Advanced Solar Technology Case	$59.04	$ -	$59.04	$141.36
PV, 200 MW, Class 1-10 + Δ Advanced Solar Technology Case	$47.68	$ -	$47.68	$114.17
Wind Class 1-10, 20 MW	$95.07	$ -	$95.07	$243.13
Portland North Coast	$120.85	$ -	$120.85	$263.74
Southern OR	$125.49	$ -	$125.49	$276.85
Walla Walla	$123.70	$ -	$123.70	$250.62
Goshen	$93.08	$ -	$93.08	$246.88
Wasatch Front	$91.95	$ -	$91.95	$245.00
Wyoming East	$66.25	$ -	$66.25	$239.38
Wind Class 1-6, 200 MW	$47.61	$ -	$47.61	$142.35
Portland North Coast	$46.37	$ -	$46.37	$152.82
Southern OR	$53.45	$ -	$53.45	$159.48
Walla Walla	$51.20	$ -	$51.20	$146.16
Goshen	$54.38	$ -	$54.38	$144.25
Wasatch Front	$53.78	$ -	$53.78	$143.30
Wyoming East	$40.28	$ -	$40.28	$140.44
Wind Class 7, 200 MW	$48.84	$ -	$48.84	$147.04
Offshore, Wind Class 12	$159.81	$ (24.12)	$159.81	$434.22
Southern OR	$114.48	$ (18.04)	$114.48	$490.83
Wind Class 1-10, 20 MW + Δ Advanced Onshore Wind Technology Case	$89.50	$ -	$89.50	$228.89
Wind Class 1-6, 200 MW + Δ Advanced Onshore Wind Technology Case	$44.28	$ -	$44.28	$133.32
Wind Class 7, 200 MW + Δ Advanced Onshore Wind Technology Case	$45.77	$ -	$45.77	$137.79
Offshore, Wind Class 12 + Δ Advanced Offshore Wind Technology Case	$43.00	$ (8.51)	$43.00	$318.06

Table C.11 – 2025 IRP Storage Supply-Side Resources, Variable O&M, Total Cost and Credits

Resource Description	Variable O&M	Credits	
	O&M ($/MWh)	Tax Credits ($/MWh) (ITC already applied)	Total Fixed Cost with Tax Credit ($/kW-yr)
Li-Ion, 4-hour, 20 MW[1]	$0.00	$ (43.07)	$170.57
Li-Ion, 4-hour, 200 MW[1]	$0.00	$ (32.28)	$139.57
Portland North Coast	$0.00	$ (34.21)	$145.16
Southern OR	$0.00	$ (34.86)	$147.03
Walla Walla	$0.00	$ (33.24)	$142.37
Goshen	$0.00	$ (32.92)	$141.44
Wasatch Front	$0.00	$ (44.32)	$125.96
Wyoming East	$0.00	$ (42.60)	$122.86
Li-Ion, 4-hour, 200 MW + Δ Double Duration, Li-Ion, 4-hour, 200MW[1]	$0.00	$ (25.77)	$230.92
Portland North Coast	$0.00	$ (27.32)	$239.86
Southern OR	$0.00	$ (27.83)	$242.84
Walla Walla	$0.00	$ (26.54)	$235.39
Goshen	$0.00	$ (26.28)	$233.90
Wasatch Front	$0.00	$ (35.39)	$209.14
Wyoming East	$0.00	$ (34.02)	$204.19
Li-Ion, 4-hour, 1000 MW[1]	$0.00	$ (33.71)	$144.13
Gravity Battery, 4-hour, 1000 MW	$0.00	$ (33.10)	$116.43
Wasatch Front	$0.00	$ (34.09)	$118.20
Gravity Battery, 4-hour, 1000 MW + Δ Double Duration, Gravity, 4-hour, 1000MW	$0.00	$ (24.62)	$196.83
Adiabatic CAES, 500 MW, 4000 MWh	$2.60	$ (27.92)	$184.94
100-hour Iron Air	$0.00	$ (37.94)	$165.17
Portland North Coast	$0.00	$ (30.15)	$200.84
Wasatch Front	$0.00	$ (39.08)	$168.98
Pumped Hydro, Two New Reservoirs, 4-hour	$0.58	$ (33.01)	$122.43
Pumped Hydro, Two New Reservoirs, 10-hour	$0.69	$ (20.83)	$182.63
Portland North Coast	$0.69	$ (22.08)	$191.45
Southern OR	$0.69	$ (22.50)	$194.39
Goshen	$0.69	$ (21.25)	$185.57
Wasatch Front	$0.69	$ (28.62)	$159.78
Wyoming East	$0.69	$ (27.51)	$154.92
Pumped Hydro, One New Reservoir, 4-hour	$0.58	$ (31.89)	$119.12
Pumped Hydro, One New Reservoir, 10-hour	$0.69	$ (17.72)	$159.69
Pumped Thermal Energy Storage, 10-hour	$0.70	$ (34.12)	$212.01
Pumped Thermal Energy Storage, 24-hour	$0.70	$ (63.70)	$390.72

1Assumed co-located

APPENDIX D - OREGON CLEAN ENERGY

Introduction

PacifiCorp's 2025 Integrated Resource Plan (IRP) Update presents a fully compliant approach to meeting Oregon obligations through long-term resource planning, near-term actions, and ongoing evaluation and execution. This appendix presents model outcomes, narratives, and reports on progress to provide an updated view of Oregon compliance from the 2025 Clean Energy Plan.

In the biannually filed IRP, the company calculates an optimal resource mix for Oregon compliance under House Bill (HB) 2021, making regulatory assumptions and evaluating risks, costs, benefits, and continual progress against targets. In years where a full IRP is not filed, the company evaluates its planning and progress toward targets through an IRP Update. Both reports present annual positions for utility and small-scale resources, energy efficiency and demand response, and project the least-cost, least-risk strategy for the achievement of clean energy targets.

The optimization modeling used by PacifiCorp incorporates all state requirements, including those associated with HB 2021, evaluating the type, size, location, and timing of resources on a proxy basis.

In Oregon's share of the 2025 IRP Update preferred portfolio, significant renewable additions of 5,371 megawatts (MW), of which 354 MW are projected to be small-scale or community-based renewable energy, are included. These are supported by a projected 20 MW of new renewable peaking resources, and 4,214 MW of energy storage. This promotes the achievement of clean energy targets, which in combination with PacifiCorp's large, interconnected grid and operational excellence serves to underscore reliability and resiliency. The resource selections in the 2025 IRP Update differ from those presented in PacifiCorp's 2025 Clean Energy Plan, filed June 30, 2025—there are 75 MW more of new total proxy supply-side resource capacity compared to the 2025 CEP preferred portfolio, made up of 304 MW less new proxy renewable capacity and 379 MW more proxy storage capacity. Additionally, compared to the 2025 CEP, the 2025 IRP Update selects 186 MW less of energy efficiency program capacity and 100 MW more of new demand response capacity.

The resource additions selected in the preferred portfolio contribute to a projected reduction in Oregon-allocated emissions of over 7.93 million metric tons of carbon dioxide equivalent (MT CO2e) from defined baseline levels by the end of 2030. PacifiCorp's 2025 IRP Update preferred portfolio, and particularly Oregon's share of that portfolio, demonstrates progress toward "an affordable, reliable and clean electric system."

Key findings

1. Oregon will require 2,538 MW of new renewable resources, 1,265 MW of shorter-duration battery storage (4-hour lithium-ion battery storage), and 429 MW of demand-side management resources by the end of 2030.
2. By the end of 2030, 197 MW of new small-scale renewable resource capacity is selected to meet small-scale renewable resource obligations.

3. By 2045, Oregon's share of the preferred portfolio includes 5,391 MW of new renewable resources to meet its energy, capacity, and clean energy needs, including 354 MW of small-scale solar resources and 20 MW of renewable peaking capacity added in 2039. These resources are supported by 4,214 MW of battery storage, over 500 MW of which is selected as 100-hour iron air batteries.
4. Oregon-allocated greenhouse gas emissions are projected to fall 88 percent from baseline levels by the end of 2030, 91 percent by the end of 2035, and 100 percent by 2040.
5. The 2025 IRP Update preferred portfolio results in over 3 GW of incremental resources to meet HB 2021's clean energy targets, relative to a counterfactual portfolio that does not include the greenhouse gas reductions goals. Similar to results presented in the 2025 CEP, the average annual cost increase of compliance with HB 2021 is $130 million, or as much as $142 million, with fully Oregon-allocated transmission investments.

Background

In 2021, Oregon Governor Brown signed House Bill 2021 (HB 2021) into law. HB 2021 defined ambitious greenhouse gas reduction requirements for electric providers, while also directing utilities to consider how to maximize additional benefits to communities. HB 2021 requires retail electricity providers to reduce greenhouse gas emissions associated with electricity sold to Oregon consumers by: 80% by 2030; 90% by 2035; and 100% by 2040.[1]

HB 2021 lays the groundwork for the transition to a clean, reliable, and sustainable energy future, but also seeks to protect and support communities who are the most vulnerable and highly impacted by the energy transition.

In service to these emissions reduction requirements, an electric company must develop a clean energy plan (CEP) for meeting relevant targets concurrent with the development of its integrated resource plan. PacifiCorp filed the 2025 IRP on March 31, 2025, and subsequently filed the 2025 CEP on June 30, 2025. This appendix offers a focused discussion on how limited modeling updates impact the preferred portfolio of resource selections and the company's progress towards and development of its clean energy targets.

The sections below summarize PacifiCorp's 2025 IRP Update portfolio assumptions and modeling process, detailing the Oregon-specific resource selections, and associated transmission investments, that will drive compliance with Oregon state policies like Senate Bill (SB) 1547 and HB 2021 while providing reliable service to customers. This appendix includes a discussion of the results from the No-HB 2021 counterfactual sensitivity, an update to PacifiCorp's projected Oregon-allocated greenhouse gas emissions and a discussion regarding compliance costs, followed by updates to the action plan defined in the 2025 CEP.

Portfolio Assumptions

The 2025 IRP Update produces an updated long-run portfolio and near-term action plan that will keep the company on a path towards compliance with HB 2021 greenhouse gas reduction targets and the small-scale renewable target while ensuring reliable service for customers.

[1] ORS 469A.410.

Refer to Chapter 3 for an overview of environmental policy regulation, including Oregon state policies. Chapter 4 presents the base load forecast and existing resources represented in modeling. Chapter 5 presents a complete list of proxy resource options available for endogenous selection, with additional details on proxy resource options presented in Appendix C. Chapter 6 explains each step involved in the development and evaluation of resource portfolios. Chapter 7 includes the preferred portfolio and list of specific resources selected to meet Oregon's compliance requirements and reliability needs.

As discussed in Chapter 6, PacifiCorp implemented key updates and methodological changes in response to changes in federal policies, updates to pricing, and stakeholder feedback that drive substantive changes to prior results presented in the 2025 IRP and 2025 CEP, as is expected and appropriate in each planning cycle. Chapter 7 includes narrative on how resource selections in this update compare to the 2025 IRP.

Portfolio Integration and Resource Allocations

The 2025 IRP introduced the process of "portfolio integration" as a methodology that optimizes each state's requirements, obligations, and resource needs, and then integrates each into a single portfolio of proxy resource selections. Every final integrated portfolio variant and sensitivity, unless otherwise stated, reflects the optimized set of proxy resource selections to meet all state obligations. Relevant here, the 2025 IRP Update preferred portfolio represents a set of resources optimized to achieve HB 2021 compliance, as well as all other PacifiCorp requirements. Refer to Chapter 6 for additional details of this portfolio integration process.

It is important to note that the 2025 IRP Update includes assumptions regarding resource cost-allocation. In lieu of a multi-jurisdictional cost allocation protocol that extends past the 2020 Protocol (set to expire December 31, 2025), all existing resources are assumed to be allocated to Oregon (both in terms of costs and generation) in accordance with the 2020 Protocol indefinitely, but incorporates the Washington 2026 Protocol which was approved for rates effective January 1, 2026, by the Washington Utilities and Transportation Commission.[2] In most cases, this means existing resources are allocated to Oregon customers based on a forecast of their system-generation (SG) factor, which is determined based on their relative jurisdictional load. In some instances, for qualifying facilities (QFs) or special customer contract resources, existing resources are situs-allocated (100 percent) to Oregon customers. Regarding new proxy resource selections, it is assumed that any new proxy resources selected to serve Oregon need are situs allocated, including both supply-side and demand-side resources.[3] These resource allocation assumptions underlie progress toward HB 2021 clean energy targets and Oregon-allocated greenhouse gas emissions, as explained below.

[2] The 2020 Protocol was adopted by the Public Utility Commission of Oregon order no. 20-024 on January 23, 2020 (available online at https://edocs.puc.state.or.us/efdocs/HAA/um1050haa161935.pdf.).
[3] The only "proxy" resource selected in the 2025 IRP that is considered a system resource and is allocated based on system generation factors is the Natrium nuclear demonstration project.

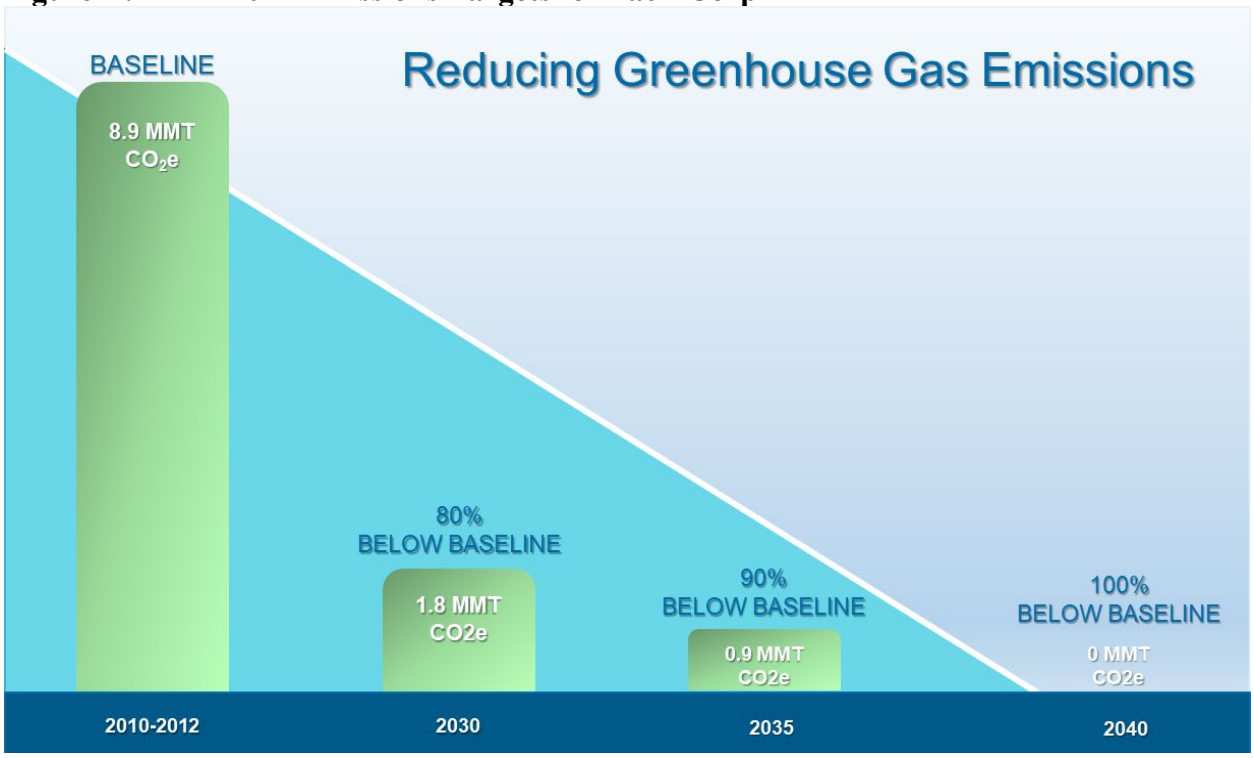
Resource Adequacy

As described in Chapters 4 and 6, the 2025 IRP Update helps ensure resource adequacy for the system and for each jurisdiction by requiring each portfolio to include sufficient resources to be compliant with the Western Resource Adequacy Program (WRAP), both in aggregate and for the loads and resources specific to the jurisdiction under evaluation. In addition, portfolios must be able to meet hourly load requirements without significant energy shortfalls, and the iterative portfolio development process increases planning requirements within the long-term (LT) capacity expansion model to account for shortfalls identified within the more granular short-term (ST) model that includes hourly dispatch outcomes.

HB 2021 Greenhouse Gas Emissions

HB 2021 directs the state's large investor-owned utilities to reduce greenhouse gas emissions associated with retail electricity sales relative to a baseline emissions level, defined as the average annual emissions of greenhouse gases associated with the electricity sold to retail electricity consumers for the years 2010, 2011, and 2012, as reported to the Oregon DEQ.[4] The DEQ's baseline emissions level determination for PacifiCorp, measured in MMT CO_2e, and corresponding emissions reductions for each clean energy target year, are reflected in Figure D.1.[5]

Figure D.1 - HB 2021 Emissions Targets for PacifiCorp



[4] ORS 469A.400(1)(a).

[5] Order Determining Baseline Emissions and Emissions Necessary to Reach Clean Energy Targets under 2021 Oregon Laws, Chapter 508 (May 25, 2022) (available online at: https://www.oregon.gov/deq/ghgp/Documents/HB2021Order.pdf).

Accounting Methodology

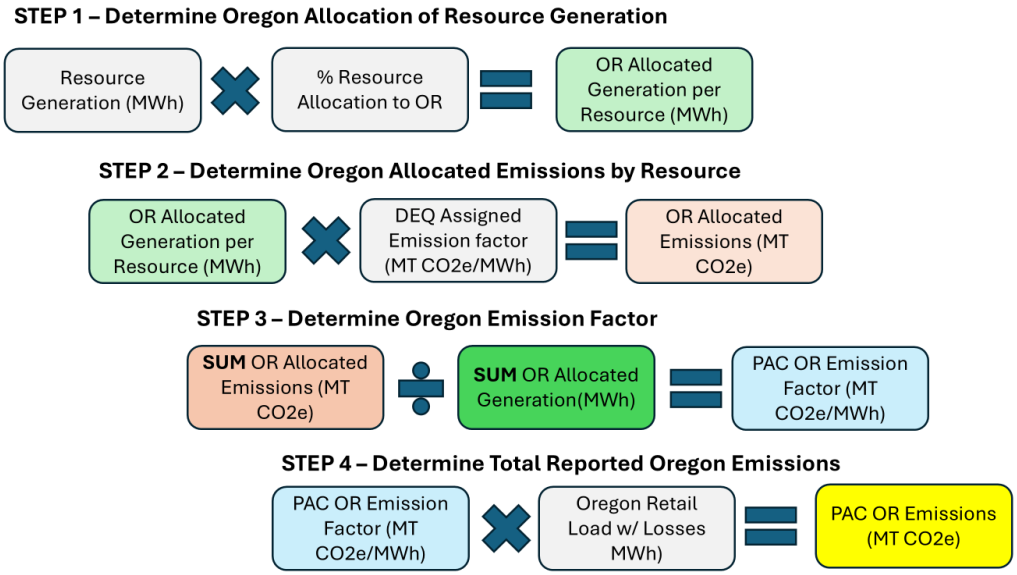
Oregon DEQ is responsible for measuring and verifying the greenhouse gas emissions that are included in a utility's CEP and reporting these findings to the Commission. Consistent with these responsibilities, Oregon DEQ published guidance for GHG emissions accounting for HB 2021 that incorporates the methodologies from the agency's longstanding Greenhouse Gas Reporting Program under OAR 340, Division 215.[6] In addition, Oregon DEQ has published guidance that directs the utilities to use unit and resource specific emission factors and default emission factors for the 2025 CEP,[7] as well as for multi-jurisdictional utility reporting, adjusting for netting wholesale sales or non-retail electricity, accounting for transmission losses, and accounting for electricity purchased from specified and unspecified sources.[8]

As a multi-jurisdictional utility, PacifiCorp's annual calculation of actual GHG follows a multi-step process.[9] First, the company determines the Oregon-allocated generation for each resource, including market purchases, according to a cost allocation methodology approved by the Commission. Second, it applies the DEQ published facility or unit specific emission factor to the Oregon allocated generation for each resource to determine Oregon allocated emissions for each resource and then totals the emissions of each resource. Purchases of unspecified power to serve Oregon retail load receive an emission factor of 0.428 MT CO2e/MWh, in accordance with DEQ's rule, and are included in the total of Oregon allocated emissions. Third, it divides the total Oregon-allocated emissions by the sum of Oregon-allocated generation to determine an Oregon-allocated system emission factor. Finally, the Oregon-allocated system emission factor is multiplied by the total amount of electricity delivered to retail customers.

A visualization of the annual GHG emissions calculation is included in Figure D.2, below. This methodology forms the basis for the calculation of compliance with HB 2021's clean energy targets. However, HB 2021 provides for some specific exclusions that are not part of the company's annual GHG emissions calculation. Notably, under HB 2021, emissions associated with electricity acquired from net metering or qualifying facilities under the terms of the PURPA are excluded from the determination of Oregon-allocated emissions.[10]

[6] ODEQ GHG Emissions Accounting for House Bill 2021, Reporting and Projecting Emissions from Electricity Using DEQ Methodology, Updated December 2022.
[7] ODEQ Specified Source Emission Factor, Updated December 4, 2023. Available online at: https://www.oregon.gov/deq/aq/Documents/ghg-SpecifiedSourceEFmethods.pdf
[8] ODEQ Multijurisdictional Utilities Instructions for Reporting Greenhouse Gas Emissions, Updated December 4, 2023. Available online at: https://www.oregon.gov/deq/aq/Documents/GHGRP-MutlijurisdictionalProtocol.pdf
[9] OAR 340-215-0120.
[10] ORS 469A.435(2).

Figure D.2 – Visual Demonstration of DEQ GHG Emissions Calculation



Forecast Greenhouse Gas Emissions

HB 2021 requires utilities to develop clean energy plans that demonstrate progress towards and projected compliance with greenhouse gas reductions targets. PacifiCorp forecasts Oregon-allocated GHG generally consistent with the established DEQ methodology for annual reporting, with certain adjustments to address long-term planning needs for a multi-jurisdictional utility.

Table D.1 provides detailed descriptions of the assumptions and authorities PacifiCorp relied on when determining total forecasted utility emissions for compliance with HB 2021.

Table D.1 – Forecast GHG Accounting Assumptions

Category	Assumption and Authority
Baseline Emissions	In May 2022, Oregon DEQ established PacifiCorp's baseline emissions levels, and emissions reductions necessary to achieve PacifiCorp's emissions reduction requirements. However, Oregon DEQ may have established an incorrect baseline emissions level, contrary to the statutory definition. The company relies on Oregon DEQ's determination in the 2025 IRP and this CEP, without conceding its accuracy.
General Calculation Methodology	PacifiCorp's initial calculation of projected emissions, before any exclusions or special treatment, is based on Oregon's long-standing Greenhouse Gas Reporting framework established in OAR 340-215 for annual actual emissions reporting. ORS 469A.420(1)(b), 468A.280.
Emission factor for existing specified resources	Oregon DEQ assigns emission factors using a tiered approach to PacifiCorp's existing facilities by unit, based on historical Oregon DEQ, EPA, and EIA data. The Oregon DEQ assigned emission factors are available online.
Emission Factors for future resources	In cases where a facility or unit-specific emission factor is either not available or applicable, DEQ directs utilities to use default emission factors by fuel type. When possible, these emission factors are based on U.S. Environmental Protection Agency's (EPA) 2022 Greenhouse Gas Emission

Category	Assumption and Authority
	Factors hub, which is available on the EPA's website. When not available, emission factors from EPA's 2020 Emissions & Generation Resources Integrated Database (eGRID) Technical Guide were used. Oregon DEQ's default emission factors are available online.
Emissions for planned coal-to-natural gas converted resources	In accordance with OAR 340-215-0040(4), a utility may petition Oregon DEQ to approve in writing an alternative calculation or method for determining an emission factor, providing an explanation and rationale for the alternative. On March 20, 2025, DEQ approved PacifiCorp's petition to use an alternative calculation method for determining the emission factor for planned coal-to-natural gas converted resource. PacifiCorp will use an emissions adjustment multiplier of 0.578, applied to the DEQ published unit-specific emissions rate for coal fired resources that are planned to convert to natural gas. PacifiCorp's alternative is more conservative than DEQ's published default emission factors for natural gas fired resources and estimates higher emissions from converted coal-to-gas units based on more accurate operational assumptions and lower efficiency of converted units relative to a combined cycle combustion turbine.
Emission factors for unspecified resources	The default emission factor is 0.428 $MTCO_2e/MWh$ for energy originating from an unspecified source. This includes purchases from a centralized electricity market, such as the Western Energy Imbalance Market. OAR 340-215-120(2)(a) and OAR 340-215-0020(64).
Transmission Losses	Electricity suppliers must include a 2 percent transmission loss correction factor when calculating emissions from generation not measured at the busbar. OAR 340-215-120(1)(b)(B)(i).
Removal of non-retail sales	According to Oregon rules that apply to multi-jurisdictional utilities, energy and emissions from the sale of specified wholesale power are not included in annual Oregon emissions totals. Rather, a multi-jurisdictional utility must remove the Oregon allocated portion of energy and emissions associated with sales from its calculations and reporting of emissions associated with the electricity the utility supplied to its Oregon retail customers. Multi-jurisdictional utilities may not subtract the energy and emissions associated with wholesale sales of unspecified energy from their Oregon allocated emissions. See OAR 340-215-0120(1)(c).
Multi-state jurisdictional reporting	Oregon rules allow for multi-jurisdictional utilities like PacifiCorp to rely on a cost allocation methodology approved by the Oregon PUC for allocating emissions associated with the generation of electricity that serves Oregon customers. OAR 340-215-0120(6)(c). PacifiCorp's most current multi-jurisdictional cost allocation methodology approved by the Oregon commission is the 2020 Protocol. While the 2020 Protocol does not extend through the planning horizon of the 2025 CEP, the company relies on this allocation methodology for the planning horizon. Under the currently approved cost allocation methodology, the utility reports a percentage of its entire multi-state system emissions based on the share of the power served in Oregon. Under all cost allocation structures, it is assumed that no coal is allocated to Oregon starting in 2030 consistent with ORS § 457.518, and that no thermal resources or market purchases are allocated to Oregon starting in 2040.

Category	Assumption and Authority
	OAR 340-215-0120 and Oregon DEQ Guidance: Multijurisdictional Utilities, Instructions for Reporting Greenhouse Gas Emissions.
Exclusions	Emissions from qualified facilities under the terms of PURPA and net metering programs are not regulated under HB 2021, and emissions from these sources are excluded from Oregon DEQ's determination of relevant emissions. The energy associated with these resources remains a part of the calculation. ORS 469A.435(3).

Market Participation

DEQ's current greenhouse gas reporting rules prevent Oregon's major utilities from participating in existing electricity markets while also meeting HB 2021's clean energy targets. As described in Table D.1 above, DEQ assigns all unspecified power – including all settlements from centralized electricity markets – a default emissions rate of 0.428 MT CO2e/MWh, regardless of the actual carbon intensity of the market power. However, even if a utility were able to petition DEQ for a lower emission rate associated with purchases from centralized electricity markets, HB 2021 requires zero emissions by 2040, meaning utilities could only participate in markets that are 100% clean – something that does not exist to date. Therefore, the current regulatory structure leaves utilities without viable market options and makes compliance with HB 2021 functionally impossible. To enable utilities to procure affordable power, maintain reliability, and still meet the state's statutory clean energy targets, DEQ must amend its rules.

PacifiCorp models long-term compliance with HB 2021 and selects a preferred portfolio, based on the assumption that no market purchases, along with their associated emissions, will be included in PacifiCorp's Oregon-allocated emissions beginning in 2035, so long as Oregon's allocation of generating resources is equal to or greater than Oregon's retail load on an annual basis. DEQ should amend its rules to reflect this modeling assumption and create a path for the utility to achieve Oregon's clean energy targets and continue to provide reliable, safe, and affordable power to its Oregon customers.

Portfolio Sensitivities/Counterfactuals

A counterfactual portfolio and a limited set of cost-specific sensitivities are included in this 2025 IRP Update to provide information regarding the timing and cost of resource procurement to comply with HB 2021 clean energy targets. Specifically, this appendix includes analysis of the preferred portfolio for Oregon customers and:

1. *No HB 2021 Counterfactual.* This portfolio identifies the set of resource selections that would serve Oregon customers absent compliance with HB 2021 greenhouse gas emissions reductions standards.
2. *Costs only – Preferred Portfolio with Situs Transmission.* This is the preferred portfolio of resources for Oregon customers, but Oregon-allocated costs are calculated assuming all Oregon state-specific driven transmission selections (i.e. included in the Oregon jurisdictional portfolio only) are situs-allocated to Oregon.

3. *Costs only – No HB 2021 Counterfactual with Situs Transmission.* This is the No HB 2021 Counterfactual portfolio, but Oregon-allocated costs are calculated assuming all Oregon state-specific driven transmission selections (i.e. included in the Oregon jurisdictional portfolio only) are situs-allocated to Oregon.

Portfolio Results

The sub-sections that follow discuss the 2025 IRP Update system and Oregon-specific resource selections, resulting greenhouse gas emissions, and transmission and small-scale resource selections.

Oregon Resource Selections

All portfolio results from the 2025 IRP Update are presented in Chapter 7, including both system and Oregon-specific resource selections.

Table D.2 specifically, shows the Oregon-allocated megawatts (MW) of resources selected in the preferred portfolio. All resource selections, except for the single nuclear resource, are assumed to represent situs-allocated resources for Oregon.

In the near-term, the 2025 IRP Update preferred portfolio selects 2,538 MW of new renewable resources to serve Oregon customers by the end of 2030, including 1,320 MW of utility-scale wind, 1,020 MW of utility-scale solar resources, and 197 MW of small-scale solar resources. The portfolio also includes over 1,270 MW of battery storage coming online in the same time period. Additionally, the portfolio optimizes DSM resources, selecting 96 MW of new demand-response, and 333 MW of energy efficiency resources by the end of 2030.

Between 2031 and the end of 2035, the portfolio includes an additional 179 MW of new renewable resources. This includes 135 MW of utility-scale wind and 44 MW of utility-scale solar. During these years, there is also significant additional storage selected: over 803 MW including both longer-duration batteries (over 24 hours) and traditional shorter-duration batteries (under 8 hours) of 457 MW and 346 MW, respectively. These years see a slightly smaller increase in new demand-response capacity, with only 63 MW added, whereas energy efficiency selections increase by 546 MW. During this time frame, Kemmerer Unit 1 is also added, which Oregon customers would receive a share of equivalent to 130 MW.

By the end of the 21-year planning horizon, over 2,960 MW of wind resources, 2,057 MW of utility-scale solar and 354 MW of small-scale solar are added to serve Oregon customers, and an additional 20 MW of renewable peaking capacity. Additionally, 4,214 MW of storage resources are added, including both shorter and longer-duration batteries. The portfolio also selects nearly 1,900 MW of energy efficiency selections and 253 MW of demand-response by the end of the period. This long-term portfolio of resources represents a pathway to meet energy needs, resource adequacy requirements and clean energy targets for Oregon.

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Table D.2- Incremental resource additions for Oregon customers, by resource allocation assumption

OR Shares by Resource Type and Year, Installed MW																				
	Installed Capacity, MW																			
Resource	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Block Product																				
Nuclear	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	20
DSM - Energy Efficiency	97	95	100	112	112	108	111	106	108	110	109	105	102	100	111	106	98	91	47	1,930
DSM - Demand Response	-	16	4	74	5	25	9	12	13	5	4	12	6	4	4	4	3	49	3	250
Renewable - Wind	-	-	137	1,183	-	-	-	11	124	93	265	148	755	-	-	-	243	-	-	2,960
Renewable - Utility Solar	-	34	0	986	-	-	-	-	-	3	259	-	-	-	-	-	774	-	-	2,057
Renewable - Small Scale Solar	-	-	13	184	-	-	-	18	26	27	29	32	25	-	-	-	-	-	-	354
Renewable - Battery (< 8 hour)	-	615	102	548	77	154	152	57	17	55	86	9	244	820	129	200	298	127	-	3,691
Renewable - Battery (24+ hour)	-	-	-	4	54	227	46	-	19	-	-	-	3	-	-	-	11	16	143	523

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Small-Scale and Community-Based Renewables

In addition to establishing greenhouse gas emissions reduction requirements, HB 2021 also amended Oregon's small-scale renewable mandate included in ORS 469A.210, by postponing compliance with the law until 2030, and increasing the target to 10 percent of PacifiCorp's aggregate electrical capacity, from the prior 8 percent.

To determine PacifiCorp's SSR target, the company identified Oregon-allocated aggregate electrical capacity in each year 2030 onwards and calculated a 10 percent small-scale requirement based on that capacity. PacifiCorp estimates it has 408 MW of existing resources in its nameplate capacity that fit the definition of SSR. This leaves an additional need for 134 MW of small-scale proxy resources to meet the forecasted target of 543 MW by 2030, as shown in Table D.3.[11] This assumes that all eligible QFs that expire before 2030 renew at 100 percent nameplate capacity, which is slightly above the 75 percent historical renewal rate.

To address the determined SSR need, the 2025 IRP Update preferred portfolio includes a slight excess of small-scale resource capacity at 197 MW of new proxy SSR-qualifying resources by 2030, with small additions over time to keep pace with additions of new utility-scale generation capacity over the planning horizon.

Table D.3 – Small-scale Resource (SSR) Target and Position

OR Small-Scale Position (MW)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Small-Scale 10% Target	543	554	568	582	601	626	653	683	715	741	662	679	694	706	718	736
Existing Small-Scale	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408	408
SSR Need	134	146	160	174	192	218	245	275	307	332	253	271	286	298	310	328
Portfolio Small-Scale Additions	197	197	197	197	215	241	268	297	329	354	354	354	354	354	354	354
Portfolio Small-Scale (Excess)	(63)	(51)	(37)	(23)	(23)	(23)	(23)	(22)	(22)	(22)	(101)	(83)	(68)	(56)	(44)	(26)

The company anticipates that some number of the proxy small-scale resources could be, and will be met, with community-based renewable energy (CBRE) projects. However, at the level of granularity the model possesses, there is no significant distinction between the two types of resources, other than potentially assuming some additional benefits are generated by CBREs relative to other small-scale renewables. CBREs, and the company's broader strategy to encourage and foster them is described in more detail in a later section.

PacifiCorp expects to meet the forecasted 2030 SSR target through a mix of existing SSR-compliant resources and the acquisition of new resources. As discussed in the action plan,

[11] This ten percent standard includes small-scale capacity in both the numerator (megawatts of small-scale generating capacity), and in the denominator (megawatts of all generating capacity). As a result, even though the small-scale capacity is 48 megawatts higher than the requirement of 675 MW, 53 megawatts of small-scale capacity could be removed from the preferred portfolio while remaining in compliance, as the total capacity for all resources following this modification (6,701 MW) would have a lower small-scale capacity requirement (670 MW).

PacifiCorp issued a small-scale renewable (SSR) request for proposals (RFP) to the market in 2025 and has recently completed its evaluation bids.

Transmission

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths. Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.

In support of the renewable resource additions identified for Oregon in the 2025 IRP Update preferred portfolio, PacifiCorp has identified transmission options that will reinforce existing transmission paths, allow for increased transfer capability, and will support the interconnection of new renewables. A summary of PacifiCorp's identified transmission additions serving Oregon and Oregon-allocated resources is shown in Table D.4 below:

Table D.4 - Transmission Selections Supporting Oregon Resources[1,2]

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2028	Serial queue: Central Oregon	0	0	152	4	100%	n/a	n/a
2029	Cluster 1 Area 11: Willamette Valley	0	0	199	14	100%	n/a	n/a
2029	Serial/Cluster 1/2: Yakima	0	0	123	13	20%	n/a	n/a
2030	Cluster 1 Area 14: Summer Lake	400	400	400	115	100%	Summer Lake	Hemingway
2030	Cluster 2 Area 23: Willamette Valley	0	0	393	2	100%	n/a	n/a
2030	Serial/Cluster 1/2: Yakima	0	0	69	7	11%	n/a	n/a
2035	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	78	59	15%	n/a	n/a
2037	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	117	92	23%	n/a	n/a
2039	Cluster 1/2/3: Walla Walla	0	0	71	75	18%	n/a	n/a
2039	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	450	450	450	481	100%	Willamette Valley	Central OR
2043	Serial through Cluster 1 Area 13: Southern Oregon	0	0	54	13	23%	n/a	n/a
Grand Total		**850**	**850**	**2,107**	**875**			

[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.

No HB 2021 Counterfactual Portfolio

As included in PacifiCorp's 2025 CEP, this IRP update includes an updated counterfactual portfolio that identifies the set of resource selection that would optimally serve Oregon customers, absent compliance with the clean energy targets set by HB 2021. In the counterfactual portfolio, the driving force of new resource selections is SB 1547 no-coal mandate, removing Oregon customers from the costs and benefits of roughly 900 MW of coal-fired resources by 2030, that are otherwise expected to serve the system. Without the inclusion of HB 2021's greenhouse gas reductions targets, however, there is more flexibility in what replacement capacity can be optimally selected to serve Oregon energy and capacity needs. Oregon's renewable portfolio standard (RPS) and SSR target are both included in the planning requirements for the counterfactual portfolio. Table D.5 summarizes the incremental resource additions for Oregon customers by resource type in the counterfactual portfolio.

The counterfactual portfolio results in 3,147 less MW of new supply-side resource capacity across the 20-year planning horizon, relative to the 2025 IRP Update preferred portfolio, primarily driven by significant reductions in selected renewable resources, specifically 2,258 MW less of new wind resources and 905 MW less of new solar resources. The counterfactual No HB 2021 portfolio does result in 36 MW more battery resources, primarily driven by a preference for more longer duration batteries, and 19 MW more of DSM program capacity.

In the near-term, the No HB 2021 counterfactual portfolio results in 2,109 MW less of new capacity by the end of 2030, relative to the preferred portfolio inclusive of the greenhouse gas reductions targets. Conversely, the counterfactual portfolio includes 172 MW more batteries by the end of 2030, relative to the preferred portfolio. Near-term differences in DSM selections are negligible. Figure D.3 depicts a summary of the annual differences in Oregon resource selections between the No HB 2021 counterfactual portfolio and the 2025 IRP Update preferred portfolio. Positive bars on the chart represent resources selected in the counterfactual, but not the preferred portfolio, and negative bars represent additional resources selected in the preferred portfolio.

Figure D.3 - Oregon Proxy Resource Selections by Year Counterfactual Portfolio Less Preferred Portfolio

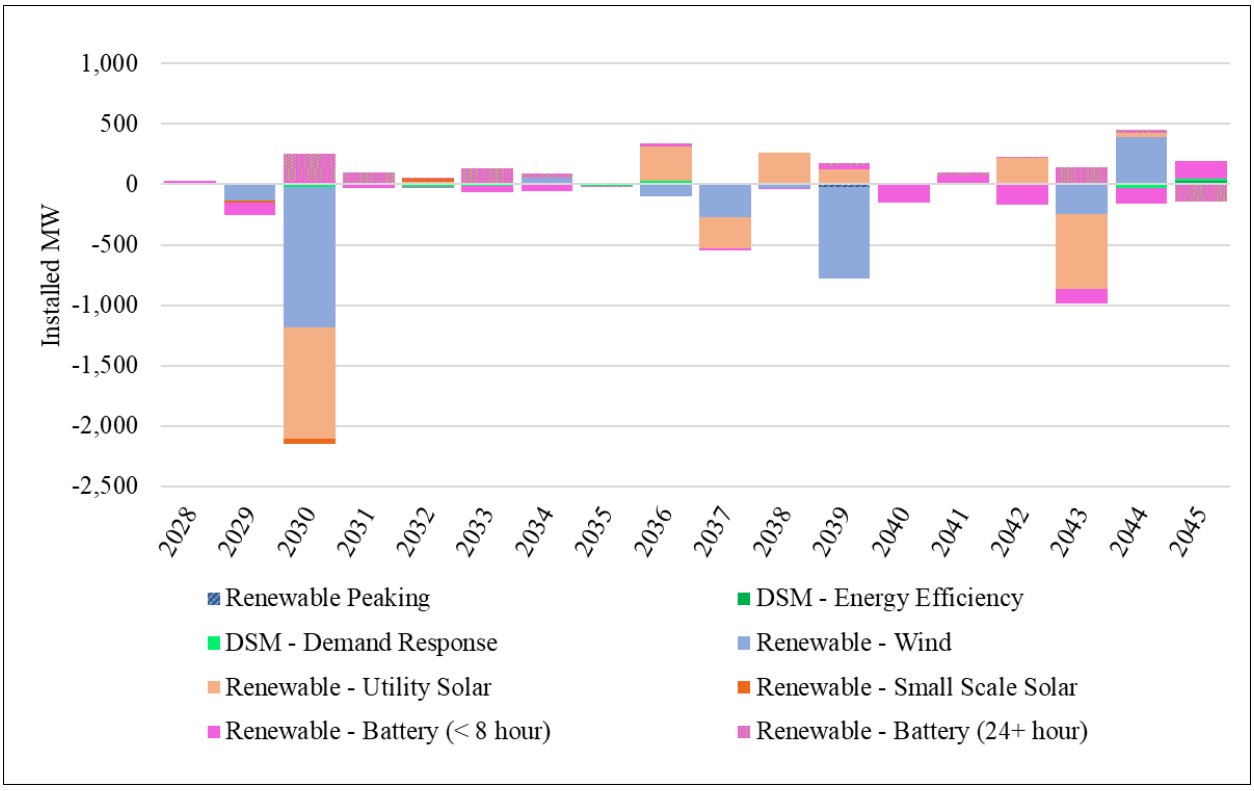

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Table D.5 - Incremental resource additions for Oregon customers, by resource allocation assumption for the No HB 2021 Counterfactual Portfolio

Counterfactual OR Shares by Resource Type and Year, Installed MW																				
	Installed Capacity, MW																			
Resource	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Block Product																				
Nuclear	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	-	98	102	109	110	106	108	103	104	105	105	107	104	103	106	110	99	92	77	1,849
DSM - Demand Response	-	22	9	57	4	5	1	26	5	35	4	19	3	12	6	6	3	15	21	254
Renewable - Wind	-	-	-	23	-	-	-	50	121	-	-	117	-	-	-	-	-	390	-	701
Renewable - Utility Solar	-	26	9	58	-	20	-	-	1	289	-	250	120	-	-	209	151	32	-	1,165
Renewable - Small Scale Solar	-	-	-	145	11	28	-	18	26	27	29	32	25	-	-	-	-	-	-	341
Renewable - Battery (< 8 hour)	-	637	-	576	53	153	100	-	24	67	66	-	278	666	202	33	175	-	141	3,169
Renewable - Battery (24+ hour)	-	-	-	229	144	234	179	34	17	10	-	-	18	-	21	2	149	46	-	1,081

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Greenhouse Gas Emissions

As described previously, PacifiCorp primarily relies on ODEQ methodologies to forecast its HB 2021 emissions based on its IRP results. The integrated portfolio methodology incorporated HB 2021 emissions reduction targets as part of Oregon's compliance obligations, ensuring they are met through a least-cost, least-risk approach. The portfolio results indicate a significant downward trend in Oregon-allocated greenhouse gas emissions, with a modest decline between 2025 and 2029, and a steeper reduction in 2030 onwards. These forecasted reductions are driven by the large addition of proxy renewable and storage resources.

The modeling process, based on emission factors and the established methodology framework – with an adjustment for Oregon's allocation of market purchases, enables the endogenous selection of proxy resources and the optimized dispatch of resources and market transactions. This approach ensures a resource portfolio that meets HB 2021 obligations for Oregon customers. Figure D.4 confirms PacifiCorp's portfolio compliance with HB 2021, though PacifiCorp notes that the resources allocated to Oregon exceed annual energy requirements.

Under current Oregon regulations, PacifiCorp is limited in its ability to continue to participate in existing electricity markets and comply with HB 2021 clean energy targets. Specifically, the company cannot request alternative emission factors for market purchases – even when data suggests emissions from market settlements are often well below the default emission rate for unspecified power – nor can the company subtract emissions associated with selling unspecified system power. In addition, the current rules require PacifiCorp to report emissions from Oregon's share of all systemwide market purchases – even if Oregon's allocated owned and contracted generation exceeds Oregon retail sales. If the company were allowed to seek alternative emission factors for unspecified power from centralized electricity markets, deduct emissions tied to wholesale sales of unspecified electricity, and apply Oregon-allocated owned and contracted renewable resources to Oregon retail sales first – without needing to assign a portion of system market purchases to Oregon's emissions – the company could further reduce reported emissions, accelerate progress toward its HB 2021 targets, and lower costs for Oregon customers.

In its long-term planning analysis, PacifiCorp assumes that achieving compliance with HB 2021 requires that (a) enough megawatt-hours of energy are allocated to Oregon to meet every megawatt-hour of Oregon load on an annual basis, and (b) that the emissions associated with those megawatt-hours do not exceed the emissions allowed under the emissions reduction target. Compliance with both requirements creates a need for significant new non-emitting generation. Additionally, Oregon's share of existing gas plants and some gas conversions are modeled as distinct units that dispatch separately from the rest-of-system share of these units.[12]

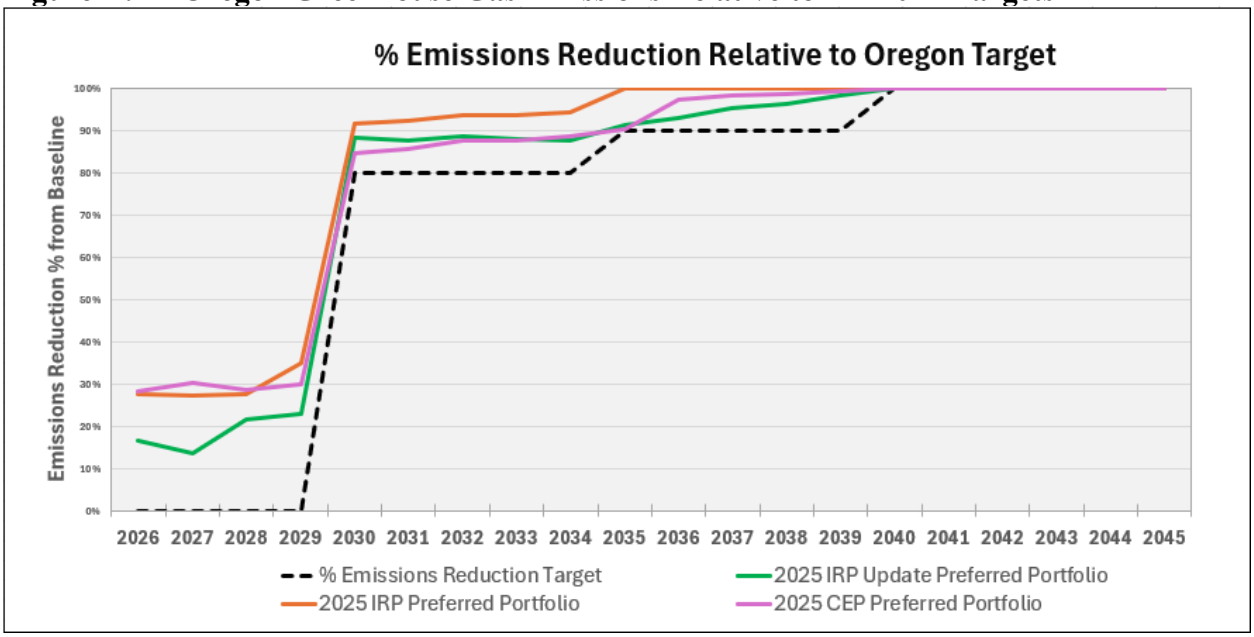
Each Oregon jurisdictional portfolio required that the model add enough megawatt-hours of new non-emitting generation to meet a majority of Oregon load in each year after 2030, ensuring that

[12] This modeling assumption allows the model to dispatch Oregon-allocated of natural gas units independently from the share of the plant dispatched for other jurisdictions without a GHG constraint. This is a modeling assumption and does not represent a specific strategy to dispatch Oregon-allocated natural gas generators in a specific way. Rather, this strategy acts a proxy for various strategies, such as situs-allocation to Oregon of only a few natural gas generators which could then be dispatched with a presumed GHG constraint.

the emissions associated with any load not met with non-emitting generation does not exceed the emissions reduction target. In addition, to represent the limit on Oregon-allocated emitting generation, a combination of model driver dispatch prices and emission constraints were applied to the emissions generated by Oregon's share of gas plants.

Figure D.4 illustrates PacifiCorp's Oregon-specific greenhouse gas emissions trajectory, relative to HB 2021 defined targets, based on the 2025 IRP Update preferred portfolio. The black dashed line represents the HB 2021 emissions reduction targets, which take effect in 2030. The 2025 IRP Update preferred portfolio produces a compliant pathway achieving required emission reductions from 2030 onward.

Figure D.4 – Oregon Greenhouse Gas Emissions Relative to HB 2021 Targets



Based on the proxy resource selections in the 2025 IRP Update preferred portfolio, PacifiCorp forecasts hitting a reduction of emissions from baseline levels of 88% by 2030, 91% by 2035 and 100% by 2040.

Compliance Costs

PacifiCorp's 2025 CEP included discussion related to the estimated incremental costs of actions taken to comply with HB 2021's clean energy targets and potential implications for a cost cap. In this 2025 IRP Update, we reproduce similar cost estimates based on the updated preferred portfolio and counterfactual analysis.

Portfolio Costs

The Oregon-allocated present value revenue requirement (PVRR) for the 2025 IRP Update preferred portfolio is $13.6 billion and the No HB 2021 counterfactual portfolio Oregon-allocated PVRR is $12.4 billion. On a present value basis, the preferred portfolio costs roughly $1.2 billion

more expensive, due to the additional resources, and associated transmission investments, necessary to hit the 2030, 2035 and 2040 decarbonization targets under HB 2021.
Notably, all portfolios are more expensive in this IRP update, compared to the 2025 IRP and CEP. This is due to changes in the planning environment, most notably the repeal of federal tax credits on new renewable resources and the increase in forward market prices. Affordability remains a top concern for PacifiCorp's customers and are at the forefront of decision making.

While the magnitude of portfolio costs is higher in this IRP Update, the relative incremental cost of HB 2021 compliance is similar to what PacifiCorp described in its 2025 CEP. Table D.6 includes a summary of nominal portfolio costs across the planning horizon for the preferred portfolio, the No HB 2021 counterfactual and both portfolios presented under a sensitivity if transmission investments considered incremental for Oregon needs were situs cost-allocated to Oregon customers. On a nominal basis, the 2025 IRP Update preferred portfolio results in an incremental cost of compliance with HB 2021 of $2.6 billion relative to the counterfactual, and this incremental cost increases to $2.8 billion with situs cost-allocated transmission costs.

Table D.6 – All Portfolio Costs (Nominal, $ millions) 2026-2045

Portfolio	2026-2029	2030-2034	2035-2039	2040-2045	Total	Incremental Cost of HB 2021 Compliance
2025 IRPU Preferred Portfolio	$2,291	$5,663	$7,680	$12,976	$28,611	$2,603
No HB 2021 Counterfactual	$2,269	$4,966	$6,845	$11,928	$26,008	-
2025 IRPU Preferred Portfolio + Situs Transmission	$2,303	$5,725	$7,827	$13,290	$29,144	$2,838
No HB 2021 Counterfactual + Situs Transmission	$2,270	$4,993	$6,941	$12,102	$26,306	-

Cost Cap Implications

To ensure an equitable energy transition and minimize customer costs, HB 2021 includes a cost cap, such that if a utility's costs to comply with the law exceed 6 percent of a utility's annual revenue requirement for a year, the Commission shall exempt the utility from compliance with Oregon's emissions reductions under certain conditions.[13]

Table D.7 summarizes the estimated average annual incremental cost associated with resource selections that would be required to comply with HB 2021 greenhouse gas reductions targets through 2040, relative to the No HB 2021 counterfactual. The table includes this average annual cost under two scenarios: one where Oregon only pays for a system-share of HB 2021-caused transmission costs, and one with full Oregon-allocation of HB 2021 transmission costs. The result is similar to analysis presented in PacifiCorp's 2025 CEP. The average annual costs are contrasted

[13] ORS 469A.445.

with PacifiCorp's Oregon revenue requirement as approved by the OPUC in PacifiCorp's most recent rate case--$1.774 billion (without escalating this figure over time to account for non-HB 2021 cost increases). [14] The nominal cost associated with incremental investments necessary to comply with HB 2021's greenhouse gas reductions targets, taken as an average of the 20 years, is $130 million additional cost per year, each year. This is equivalent to an annual 7.24% increase from current revenue requirement (again, holding constant changes in the baseline). If transmission investments driven by HB 2021 requirements were fully allocated to Oregon customers, this average annual cost would increase to $142 million on average per year, an 8% increase over current revenue requirement.

Table D.7 - Estimated HB 2021 Average Annual Compliance Costs 2025-2045 ($millions) and Percentage of 2025 Revenue Requirement (shown in parenthesis)

	Annual Cost with System Transmission	Annual Cost with Situs Transmission
2025 IRPU Preferred Portfolio	$130 (7.34%)	$142 (8%)

Importantly, these figures also include two untested assumptions: (1) that all resources otherwise necessary to comply with Oregon's no-coal mandate (which by definition must also be HB 2021-compliant), are not included in HB 2021's cost cap; and (2) that while HB 2021's cost cap does not apply to SSR resources, the SSR resources necessary to meet the incremental 10 percent SSR obligation for HB 2021 resources are included (though the incremental SSR capacity included in the HB 2021 compliant portfolio is very small).

PacifiCorp will continue to evaluate potential cost impacts to customers from large-scale resource build out and investments necessary to comply with Oregon state policies.

2025 Clean Energy Action Plan – Status Updates

PacifiCorp's 2025 CEP, Chapter IX presented a near-term Oregon-specific action plan identifying steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio and make necessary progress towards clean energy targets and other requirements under HB 2021. In this 2025 IRP Update, PacifiCorp presents a status update on those action plan items and calls out new action items as a result of recent regulatory activity.

The action matrix in Table D.8 is an Oregon-specific view that expands upon the systemwide action plan to include other actions that broadly support the company's progress and fulfillment of HB 2021 goals, such as community and stakeholder engagement, activities related to CBIs, and forthcoming regulatory filings and actions.

[14] *E.g., In re PacifiCorp's 2024 Oregon Rate Case,* UE 433, Order No. 24-447 (Dec. 19, 2024).

Table D.8 - Clean Energy Action Plan – Status Updates

Action Item	Existing Resource Actions	Status Update
1a	**Natural Gas Emissions Compliance Strategies:** • The 2025 CEP indicates that changes in accounting and/or dispatch of existing natural gas resources may be beneficial for HB 2021 compliance strategies and to align with evolving state policies. PacifiCorp will continue investigating strategies with impacted parties, program administrators, and regulators on available options to prepare for implementation no later than 2030.	PacifiCorp continues to investigate strategies for the accounting and/or dispatch of existing natural gas resources.
	New Resource Actions	**Status Update**
2a	**Small-scale renewables RFP:** • On April 23, 2025, PacifiCorp issued an OR SSR RFP. • PacifiCorp will continue to investigate, develop, and pursue other strategies, as outlined in its SSR Acquisition Strategy filed concurrently with the 2025 IRP, to increase its small-scale and community-based resources. • PacifiCorp will evaluate opportunities to accelerate procurement of resources identified in the preferred portfolio in 2030 when evaluating proposals from the 2025 OR SSR.	The April 23, 2025, OR SSR RFP did not yield any compliant bids. On July 25, 2025, PacifiCorp publicly announced the reissuance of the OR SSR RFP and held a second bidder workshop for the 2025 OR SSR RFP on July 30, 2025. Bid submissions were due by December 17, 2025. PacifiCorp has recently completed its evaluation of bids.
2b	**2025 Oregon-situs RFP:** • On April 16, 2025, PacifiCorp filed the draft 2025 OR Situs RFP to procure Oregon situs resources that can achieve commercial operations by the end of December 2029. PacifiCorp expects a Commission decision regarding approval of the RFP by early	On October 13, 2025, PacifiCorp issued the 2025 Oregon Situs RFP to the market. PacifiCorp received final bids by November 18, 2025. PacifiCorp is in the process of evaluating bids with a target to produce a Final Shortlist in June. More information on the RFP timeline is included in the discussion that follows.

	October 2025. Following approval, PacifiCorp will issue the RFP to market. • PacifiCorp will evaluate opportunities to accelerate procurement of resources identified in the preferred portfolio in 2030 when evaluating proposals from the 2025 OR Situs RFP.	
2c	**Transmission:** • Ensure that PacifiCorp's planning, siting, and development of Oregon-sited distribution and transmission resources minimizes impacts to PacifiCorp's Oregon EJ Communities.	PacifiCorp continues to ensure that PacifiCorp's planning, siting, and development of Oregon-sited distribution and transmission resources minimizes negative impacts to communities.
	Demand-Side Management (Actions)	**Status Update**
3a	**Energy Efficiency** • In 2025, PacifiCorp will continue collaborating with the ETO to review their proposed inaugural MYP that will establish their energy efficiency targets, corresponding budgets, and cross-organization support for the next five-year period (2026-2030).	In 2025, PacifiCorp reviewed and commented on ETO's inaugural MYP's energy efficiency targets and budget. Now in 2026, PacifiCorp has begun the process of cross-organization support and oversight of ETO's implementation of their MYP across its five-year time horizon (2026-2030).
3b	**Demand Response** • PacifiCorp will continue to expand its portfolio of DR programs by launching three new programs in 2025: Wattsmart Battery, Wattsmart Drive, and Cool Keeper. • In 2026 and beyond, the company will focus on sustaining a rapid pace of growth in existing programs, to double the total DR capacity by 2027.	In 2025, PacifiCorp filed three new DR programs: Wattsmart Battery, Cool Keeper, and Wattsmart Drive. Wattsmart Battery and Cool Keeper have launched to customers. Wattsmart Drive is in the start-up phase, developing and testing communication and control systems. PacifiCorp files an annual report on DR program and portfolio-level performance under Docket ADV 1383 on March 31st of each year. For 2026, PacifiCorp is implementing a number of program improvements to drive increased capacity and expects to meet or exceed the 3-year DR forecast included in the 2025 CEP.

	Community-Based Renewable Energy Actions	Status Update
4a	• Provide an annual CBRE assessment and report and continue to strengthen partnerships with ETO. • Consider a Blue Sky Grant Program "Go-Back" strategy.	The CBRE-RH Pilot was approved and rolled out in 2025. PacifiCorp will report on 2025 activity within the annual Demand Response report, filed later in Spring 2026.
	Community Engagement	**Status Update**
5a	**Advisory Groups** • PacifiCorp will continue to include an update on various elements of the CEP in the CBIAG meetings (including Tribal Nations-focused meetings) through 2025.	PacifiCorp included an update on the CEP at the July 17, 2025, and October 16, 2025, CBIAG meetings. PacifiCorp is working to evaluate how to better engage advisory groups on elements of the CEP planning and implementation process in preparation for the 2027 CEP.
5b	**CEP Engagement Series** • PacifiCorp will continue to offer Oregon CEP engagement series meetings, with four regular sessions scheduled in 2025, with opportunity for additional special meetings as requested or required, as an avenue for expanded learning and dialogue on key clean energy planning topics.	Following the publication of the CEP, PacifiCorp offered a CEP engagement meeting on August 20, 2025. Topics included the CEP, Oregon regulatory updates, and Oregon RFP updates. In 2026, PacifiCorp will continue to offer CEP-related engagement through the 2027 IRP public input meeting process to avoid burdensome duplicative meetings
	Community Benefit Indicators	**Status Update**
6a	• PacifiCorp has proposed two new CBI metrics: SO_2 and NOx and will continue to solicit input and feedback from its advisory groups and interested parties and finalize the proposed metrics.	No material updates.
6b	• PacifiCorp will continue refining its CBI framework, evaluating current CBIs and proposed metrics to establish a clear baseline and transparent framework for use in resource procurement, planning, and other relevant business decisions.	Over the course of 2026, PacifiCorp expects to continue to engage with its advisory groups on refinement of its CBI framework. The company will report out on this activity and any resulting changes to the framework in its 2027 CEP filing.

6c	• PacifiCorp will work with advisory group members and other interested parties to develop a proposal to more fully define environmental justice communities within its service area over the one to two years.	On January 27, 2026, the company hosted a CEP engagement to introduce the Environmental Justice Community Framework, or index, to its advisory groups and other stakeholders. Over the course of 2026, the company will continue to engage with its advisory groups to refine and finalize the index and apply it to CBI outcome reporting.
	Regulatory Actions	**Status Update**
7a	**<u>Agency Engagement</u>** • PacifiCorp will engage with Oregon DEQ in any upcoming relevant rulemakings to address changes to the methodology and calculations of greenhouse gas emissions for purposes of demonstrating progress towards clean energy targets. • PacifiCorp will continue to engage with the Commission and stakeholders in docket UM 2273 regarding the implementation of HB 2021's cost cap. • PacifiCorp will continue to work with the Commission and stakeholders regarding PacifiCorp's request for clarification on Oregon's SSR mandate. • PacifiCorp continues to engage with CAISO, regulators, and other stakeholders in developing a greenhouse gas accounting and reporting framework for market participation.	• PacifiCorp continues to engage with Oregon DEQ in anticipation of future relevant rulemakings that address changes to the methodology and calculations of greenhouse gas emissions for purposes of demonstrating progress towards clean energy targets. • PacifiCorp submitted two rounds of comments in UM 2273 and participated in a Commissioner Workshop on August 12th, 2025. • PacifiCorp worked with Staff and stakeholders to clarify the implementation of Oregon's SSR mandate. On November 28th, 2025, the Commission held a public meeting to move to formal rulemaking. PacifiCorp submitted additional comments on January 23rd, 2026. • On October 15, 2025, CAISO published its final proposal for a Greenhouse Gas Accounting and Reporting Initiative. The primary purpose of the proposal is to increase transparency of the GHG emissions intensity of electricity transfers in the WEIM and EDAM. PacifiCorp participated in the GHG Coordination working group that helped CAISO develop the final proposal.
7b	**<u>IRP OR Stakeholder Workshop – Modeling Updates*</u>** **new since 2025 IRP/CEP filings*	On April 10, 2026, PacifiCorp will hold an IRP workshop with Oregon stakeholders to introduce and discuss

		modeling approaches that are responsive to feedback received in LC-85 and in support of a June Supplemental filing (per OPUC Order No. 26-054). More information is included in the discussion that follows.
7c	**June Supplement*** **new since 2025 IRP/CEP filings*	PacifiCorp will make a supplemental filing to the 2025 IRP/CEP by July 1, 2026, in fulfillment of Commission Order No. 26-054 Recommendation 2 and Recommendation 10. More information is included in the discussion that follows.

LC 85 Order 26-054 Non-Acknowledgement and Conditions

On February 24, 2026, the Public Utility Commission of Oregon (OPUC) issued Order 26-054, declining to acknowledge PacifiCorp's 2025 IRP long-term resource strategy and the 2025 CEP.[15] Additionally, the Commission adopted several staff recommended conditions. Discussed below are some of the recommendations that directly impact Oregon specific elements of the action plan in this 2025 IRP Update. In addition to the traditional table-format of action plan items presented in the previous subsection of this appendix, PacifiCorp also provides the following action plan narrative.

Per the order, PacifiCorp is required to meet the following conditions regarding acquisition planning and strategy:[16]

3. *We acknowledge the following IRP and CEP action items with conditions:*

    a. *Acknowledge Action Items IRP 2b and CEP 2b under the conditions that PacifiCorp, as part of its 2025 IRP Update or a separate filing before July 2026,*

        i. ***Present a resource acquisition plan that addresses system reliability as well as state-specific needs and includes annual targets and important milestones*** *(Recommendation 2), and*
        ii. ***For HB 2021 compliance, provide a structured execution strategy with time-bound deliverables regarding procurement, allocation of existing resources, clean market purchase, and gas dispatch*** *(Recommendation 10).*[17]

PacifiCorp will make a separate filing in docket LC 85 by July 1, 2026, addressing Recommendation 2 and Recommendation 10 in full, but offers an initial discussion here.

[15] Commission Order No. 26-054 entered February 24, 2026 in docket LC 85, available online at https://apps.puc.state.or.us/orders/2026ords/26-054.pdf.
[16] Commission Order No. 26-054, page 2.
[17] See Appendix G, stakeholder feedback form #20 (Public Utility Commission of Oregon)

Resource acquisition plan

PacifiCorp maintains that each IRP necessarily provides a proxy-based resource acquisition plan and that the 2025 IRP and IRP Update processes included analysis that appropriately addressed system reliability as well as state-specific needs. Each IRP's preferred portfolio of resource selections sets the "annual targets" for resource volume, technology and timelines the company is targeting. However, because the plan is proxy based, it is expected that actual acquisition volumes, technology types, locations and commercial online dates of new resources will differ based on market availability. The proxy-based plan can and should change with each planning cycle as updated information becomes available and is incorporated into the determination of annual resource selections. With this narrative in mind, PacifiCorp relies on its IRP to send a signal to the market and relies on a competitive procurement process, like an RFP, to determine the cost-effective resource mix to be acquired to serve customer needs and meet state regulatory requirements. This process demands flexibility in an ever-changing planning environment.[18]

PacifiCorp includes here the long-term proxy-based resource acquisition plan to serve Oregon customers, based on the 2025 IRP Update:

Table D.9 – Summary of Oregon Resource Shares, Preferred Portfolio

Oregon Resource Selections, by category and years, Installed MW			
	2026-2030	**2031-2040**	**2041-2045**
Energy Efficiency	333	1,072	454
Demand Response	96	94	63
Wind	1,320	1,397	243
Solar	1,020	262	774
Small-scale Renewable	197	157	-
Nuclear	-	130	-
Renewable Peaking	-	20	-
Storage	1,270	2,020	925

Significant stakeholder discussion regarding the results of the 2025 IRP questioned the analytical underpinnings of PacifiCorp's jurisdictional modeling approach introduced in the 2025 IRP. This 2025 IRP Update reflects several important narrative and analytical additions in response to some of that feedback. Table D.8 includes a relevant action item, and as discussed in subsequent narrative, PacifiCorp will workshop with parties a different modeling approach. The new approach will serve as the basis for future analytical determination of the systemwide integrated preferred portfolio and an updated resource acquisition plan, further fulfilling the requirements of Recommendation 2.

[18] See Appendix G, stakeholder feedback form #20 (Public Utility Commission of Oregon)

Current time-bound execution strategy and actions

On February 19, 2026, OPUC Commission Staff filed an update to the schedule for PacifiCorp's 2025 Oregon Situs RFP.[19] At the time of filing this update, PacifiCorp remains on the published timeline for completion of this RFP. Staff's published schedule is recreated in Table D.10.

Table D.10 – 2025 Oregon Situs RFP Schedule

Event	Date
PacifiCorp issues raw price bid rankings	April 10, 2026
PacifiCorp provides FSL sensitivity analysis & workpapers to IE and Staff.	April 10, 2026
PacifiCorp may file request for acknowledgement of FSL and IE closing report.	May 14, 2026
FSL Commission Workshop	May 21, 2026
10-day response time for information request begins.	May 21, 2026
Staff and Parties file comments on Final Shortlist.	June 4, 2026
PacifiCorp files response to comments.	June 9, 2026
Staff report on Final Shortlist.	June 11, 2026
Public Meeting for Commission decision on acknowledgement of Final Shortlist.	June 23, 2026

PacifiCorp will continue to work through its ongoing RFP process with the goal of procuring near-term resources to provide necessary non-emitting energy and reliability to Oregon customers by 2030 and as directed by the Commission.

Expectations for future analysis

Significant analytical milestones provide the opportunity to update inputs, methodologies, and analysis in response to changes in the planning environment and also to stakeholder feedback and regulatory direction. Openness to these three avenues of input requires flexibility and the recognition that updated studies will, with certainty, result in changes from the resource acquisition signal described above, and resulting from this 2025 IRP Update. The next significant milestones in the CEP/IRP process are anticipated to be the "June Supplement" (Order 26-054 items 3a, 3b and 6), followed by the Draft 2027 IRP at the end of November 2026, and the final 2027 IRP to be filed on March 31, 2027.

The June Supplement will provide additional insight using modified methods and assumptions which will be further responsive to feedback and regulatory direction, in particular with regard to baseline modeling and the determination of estimated incremental costs relevant to the cost cap. PacifiCorp has scheduled an IRP stakeholder workshop for April 10, 2026 to discuss approaches that are responsive to feedback received in the 2025 IRP process and direction in Order 26-054,

[19] Docket UM 2383, Commission Staff filing on February 25, 2026 "Staff's Schedule Update" available online at https://edocs.puc.state.or.us/efdocs/HAH/um2383hah344102037.pdf.

with the goal to present an updated modeling methodology as the basis for an updated resource acquisition plan and HB 2021 compliance strategies.

For HB 2021 Compliance and Continual Progress

In Order 26-054, the Commission also included the following statement and direction:[20]

> *6. We decline to adopt Staff's motion part 6, and instead direct Staff to bring a recommendation on whether the company has demonstrated continual progress towards meeting HB 2021 emissions goals to a future public meeting to allow consideration of the information direct in part 3a (Recommendations 2 and 10) to be filed in either the company's IRP Update or a separate filing before July 2026. We direct that this filing also include a discussion:*
>
> - *of what was procured in phase 1 of the 2025 RFP,*
> - *of the impact of EDAM on the use of unspecified market transactions and how to maximize the value of EDAM while maintaining HB 2021 compliance, and*
> - *that provides an update on PacifiCorp's investigation into the availability of clean market products to allow all parties to gain a better understanding of the options and limitations of products available in the market to meet both reliability and our clean energy goals*.

In the planned June Supplemental filing, PacifiCorp will include narrative that addresses the direction in item 6, in addition to analysis and narrative in fulfillment of Recommendations 2 and 10.

[20] Commission Order No. 26-054, page 5-6.

APPENDIX E - WASHINGTON INTERIM TARGETS

Introduction

PacifiCorp's 2025 Integrated Resource Plan (IRP) Update presents a fully compliant approach to meeting Washington's energy, capacity and policy requirements through long-term planning, near-term actions, and ongoing evaluation and execution. This appendix, based on the Washington-allocated results of the 2025 IRP Update preferred portfolio, presents a limited update on forecasted clean energy interim targets.

The 2025 IRP, inclusive of the Washington Clean Energy Action Plan, served as the foundation for PacifiCorp's 2025 Clean Energy Implementation Plan, filed October 1, 2025.[1] The 2025 CEIP presented a near-term action plan consistent with the long-term resource strategy to make progress towards the goals set by the Clean Energy Transformation Act (CETA). In this appendix, the company presents an update on the clean energy interim targets consistent with the updated preferred portfolio, showing that PacifiCorp remains on the path described in the 2025 CEIP.

Key Updates

1. The 2025 IRP Update results in 1,071 MW less new proxy resource capacity than the 2025 CEIP preferred portfolio. This change is largely driven by reduced capacity needs as a result of the recently approved Washington 2026 Protocol.
2. In the near-term, Washington customers will require 284 MW less of new situs-allocated renewable resources before the end of 2030, and 362 MW less of battery storage compared with the 2025 CEIP preferred portfolio.
3. PacifiCorp projects meeting CETA's 2030 greenhouse gas neutrality target by generating CETA-compliant energy equivalent to 100% of Washington retail sales beginning 2030, but PacifiCorp continues to evaluate the best cost-effective approach to meeting long-term goals and

Portfolio Development

Like the 2025 IRP and CEIP development processes, the 2025 IRP Update results in a preferred portfolio of resource selections based on system loads, existing resources, proxy resource options available for endogenous selection, and a rigorous suite of modeling tools and analytics. The 2025 IRP Update results in a portfolio that is optimized under all requirements and conditions to create a portfolio that is compliant with Washington policies and regulations.

Refer to Chapter 3 for an overview of environmental policy regulation, including Washington state policies. Chapter 4 presents the base load forecast and existing resources represented in modeling. Chapter 5 presents a complete list of proxy resource options available for endogenous selection, with additional details on proxy resource options presented in Appendix C. Chapter 6 explains each step involved in the development and evaluation of resource portfolios. Chapter 7 includes

[1] PacifiCorp's 2025 CEIP is available online in docket UE-250617 at https://apiproxy.utc.wa.gov/cases/GetDocument?docID=16&year=2025&docketNumber=250617.

the preferred portfolio and list of specific resources selected to meet Washington's compliance requirements and reliability needs.

Generally, the processes for portfolio development, jurisdictional modeling and integration resulting in the 2025 IRP Update Washington-allocated preferred portfolio are consistent with methods described and used in the 2025 IRP and CEIP. Any changes to baseline modeling assumptions in this IRP update are described in Chapter 6.

There is one significant assumption change regarding Washington resource allocations. On December 22, 2025, the Washington Utilities and Transportation Commission (WUTC) issued Final Order 08 approving the Washington 2026 Protocol, to be adopted for rates effective January 1, 2026, superseding the Washington Inter-Jurisdictional Allocation Methodology (WIJAM).[2] As described in PacifiCorp's 2025 CEIP[3] and in testimony presented in the 2025 Power Cost Only Rate Case (PCORC), the Washington 2026 Protocol varies from the WIJAM in key ways and is expected to improve PacifiCorp's ability to plan for and meet CETA clean energy goals.[4] The new allocation protocol is reflected in the 2025 IRP Update jurisdictional modeling for Washington.

Portfolio Results

All portfolio results from the 2025 IRP Update are presented in Chapter 7. Table 7.4, specifically, shows the Washington-allocated megawatts (MW) of resources selected in the updated preferred portfolio. Table E.1 repeats the same information that is presented in Chapter 7 Table 7.4. All resource selections, except for the single "nuclear" resource category, represent situs-allocated resources for Washington customers.

[2] WUTC Order 08 Final Order in UE-250224 available online at https://apiproxy.utc.wa.gov/cases/GetDocument?docID=1170&year=2025&docketNumber=250224.
[3] PacifiCorp's 2025 CEIP, Chapter IV – Portfolio Development, page 34.
[4] See PacifiCorp direct testimony in docket UE-250224 online at https://www.utc.wa.gov/casedocket/2025/250224/orders.

Table E.1- Incremental Resource Additions for Washington Customers, by Resource Allocation Assumption

WA Shares by Resource Type and Year, Installed MW																				
	Installed Capacity, MW																			
Resource	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	32	-	-	-	-	-	-	-	-	-	-	-	-	-	32
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	16	15	16	18	21	21	21	21	20	19	20	16	15	13	11	12	8	7	5	296
DSM - Demand Response	0	8	17	1	2	-	7	-	1	0	0	1	1	1	14	0	0	1	0	55
Renewable - Wind	-	-	228	514	-	-	-	-	-	0	3	-	-	-	-	-	-	-	-	745
Renewable - Utility Solar	-	220	125	72	-	-	-	-	-	2	-	-	-	-	-	-	-	-	-	419
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (< 8 hour)	-	100	-	-	-	-	-	-	-	-	-	-	-	213	-	-	-	-	-	313
Renewable - Battery (24+ hour)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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In the near-term, the 2025 IRP Update preferred portfolio selects 1,513 megawatts (MW) of new renewable resources situs to Washington customers, expected to come online by the end of 2030, including 1,117 MW of wind and 396 MW of utility-scale solar. In this same time frame, 82 MW of battery storage (4-hour lithium-ion battery storage) are also selected to meet Washington's resource adequacy and capacity needs. The portfolio also includes 50 MW of additional energy efficiency selections and 35 MW of demand response by the end of 2030.

From 2031 to 2045, 3 MW of new solar is selected for Washington with no other renewable resource additions selected. An additional 185 MW of new battery storage is selected during this timeframe, all between the years 2040 and 2045. Finally, 226 MW of new energy efficiency and 26 MW of new demand response are added between 2031 and 2045 for Washington customers. Over the entire 20-year planning horizon, through 2045 when CETA's zero-greenhouse gas emitting standard begins, the preferred portfolio selects over 1,500 MW of new renewable resources, nearly three quarters of which is new wind, and the rest is new solar. The portfolio also includes minor battery storage selections totaling 267 MW. Total energy efficiency selections equate to 276 MW and demand-response selections total 61 MW

Clean Energy Interim Targets

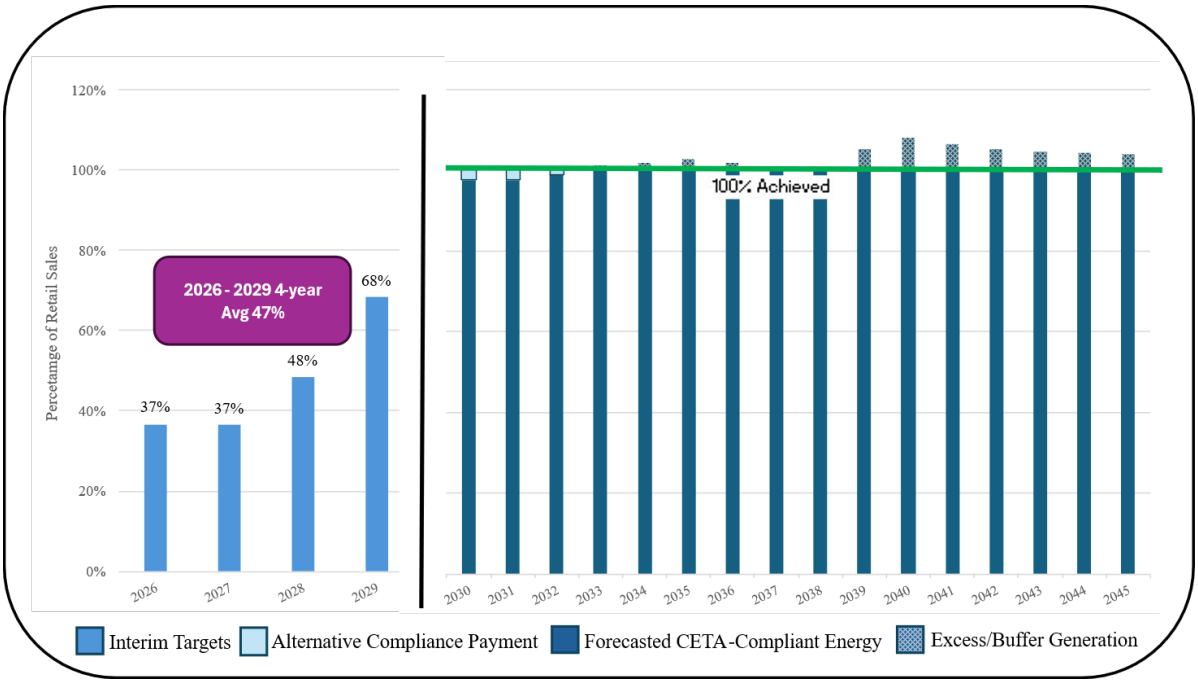
RCW 19.405.040 and 19.405.050 set the 2025, 2030, and 2045 targets for electric utilities in Washington to meet. Specifically, utilities must show that by December 31, 2025, all coal-fired resources have been removed from Washington's allocation of electricity. By January 1, 2030, utilities must be greenhouse gas neutral, and by 2045, Washington's electric utilities must be 100% renewable or non-emitting.

RCW 19.405.090 sets out four alternative compliance pathways that can be used to meet up to 20% of the carbon neutrality standards that begin in 2030 and run through 2044:

> (i) Making an alternative compliance payment under RCW 19.405.090(2);
>
> (ii) Using unbundled renewable energy credits, provided that there is no double counting of any nonpower attributes associated with renewable energy credits within Washington or programs in other jurisdictions, subject to conditions outlined in CETA;
>
> (iii) Investing in energy transformation projects, including additional conservation and efficiency resources beyond what is otherwise required under this section, provided the projects meet the requirements of subsection (2) of this section and are not credited as resources used to meet the standard under (a) of this subsection; or
>
> (iv) Using electricity from an energy recovery facility using municipal solid waste as the principal fuel source, where the facility was constructed prior to 1992, and the facility is operated in compliance with federal laws and regulations and meets state air quality standards, subject to conditions outlined in CETA.

The 2025 IRP Update preferred portfolio, optimized and dispatched under the social cost of greenhouse gas (SCGHG) price policy for Washington customers, currently forecasts that PacifiCorp will be on track to meet the compliance requirements in 2030 and 2045.

Figure E.1 – PacifiCorp's 2025 IRP Update – Clean Energy Interim Targets 2026-2045



Under the projection of the 2025 IRP Update, PacifiCorp would expect to use the alternative compliance payment, energy transformation project, or energy recovery facility pathway to meet the standards under RCW 19.405.090 from 2030 through 2032 when only around 97-99% of retail sales are forecasted to be served by CETA-compliant resources. For example, PacifiCorp could purchase unbundled renewable energy credits (RECs) up to 20 percent of the compliance obligation. Even for years when PacifiCorp projects generating over 100 percent of retail sales from CETA-compliant generating, depending on actual weather conditions, alternative compliance methods may be required when generation outcomes are worse than expected. Alternative compliance methods remain a key and potentially cost-effective, means to achieve compliance between 2030 and 2044.

Table E.2 reports updated interim targets for the company's second CEIP planning period for the years 2026-2029, reported as annual megawatt hours of energy rather than as percentages.

Table E.2 – Clean Energy Interim Targets for Washington, 2026-2029

	2026	2027	2028	2029	Total
Retail Electric Sales (Adjusted)[1]	4,076,838	4,203,805	4,335,371	4,306,457	16,922,471
Projected Renewable and Nonemitting Energy	1,496,120	1,537,327	2,096,590	2,943,614	8,073,651
Net Retail Sales	2,580,717	2,666,478	2,238,782	1,362,842	8,848,820
Target Percentage	37%	37%	48%	68%	
Interim Clean Energy Target	1,496,120	1,537,327	2,096,590	2,943,614	8,073,651

[1]Retail electric sales less qualifying facilities generation

The 2025 IRP Update results reaffirm the near-term targets and action plan defined in PacifiCorp's 2025 CEIP and the company is not seeking a formal update or change to its near-term targets based on this IRP Update. The clean energy interim targets present here are used to verify and assess that compliance is being achieved and planned for in the IRP process. Any formal changes to near-term interim targets, and other specific targets and actions will be included in subsequent filings in PacifiCorp's 2025 CEIP docket.[5]

[5] See WUTC docket UE-250617, PacifiCorp's 2025 CEIP. Review online at https://www.utc.wa.gov/casedocket/2025/250617/docsets.

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APPENDIX F – CALIFORNIA UPDATE

Introduction

In accordance with Decision D.18-02-018 and D.22-02-004 in R.25.06-019, PacifiCorp must is file an individual integrated resource plan (IRP) with the California Public Utility Commission (CPUC) by August 10, 2026. While all LSEs filing a standard plan must use the Narrative Template, Resource Data Template, and Clean System Power calculator specified in R.25.06-019, small and multi-jurisdictional utilities such as PacifiCorp may use the Resource Data Template and Clean System Power calculator for non-standard plans but are not required to do so.[1]

PacifiCorp's proposed methodology for calculating California allocated GHG to meet the GHG benchmarks outlined by the CPUC is presented below. California LSEs are assigned their proportional share of the GHG benchmark for the electric sector, based on their load forecast share. PacifiCorp's share of the GHG benchmark is 0.209 MMT by 2030, 0.175 MMT by 2035 and 0.065 MMT by 2045. PacifiCorp has prepared its California Allocated GHG position for the 2025 IRP Update preferred portfolio, presented in Table F.1.

The Clean System Power calculator or an MJRP's alternative GHG benchmark calculator are not intended to be used as after-the-fact compliance tools. Rather the GHG benchmark calculators are intended to provide LSE's a simple way of estimating emissions associated with IRP portfolios and assist in an LSE's plan to contribute proportionally to California's statewide decarbonization.

Methodology and Assumptions

For the California GHG Benchmark position calculations, PacifiCorp applied the same methodology used for reporting greenhouse gas emissions for Electric Power Entities (EPE) under the California Air Resources Board (CARB) Mandatory Greenhouse Gas Emissions Reporting Program, consistent with the program guidelines and Workbook One and Workbook Two for Multi-Jurisdictional Retail Provider (MJRP) calculation frameworks.[2] PacifiCorp proposes using this methodology as an alternative calculator for the California GHG Benchmark analysis and modeling going forward.

Resources that are cost-allocated to California retail customers were identified and emissions were calculated based on total system generation without applying cost-allocation factors. Emissions associated with imported power were calculated using the MJRP emission factor multiplied by California retail sales served by imported power. Retail sales served by imported power were determined by subtracting in-state California generation (generation from resources physically located within California) from total California retail sales. California retail sales were adjusted to

[1] Results from ALJ Ruling R.25-06-019; Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M595/K085/595085015.PDF

2 California Air Resources Board, Mandatory Greenhouse Gas Emissions Reporting Regulation (MRR), Title 17, California Code of Regulations, section 95111(b)(3)–(5). Available at: https://govt.westlaw.com/calregs/Document/I01BDA8725A2111EC8227000D3A7C4BC3?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default)

reflect a 2 percent transmission loss factor, consistent with CARB's guidance. Emissions associated with market purchases were calculated using CARB's default emission factor of 0.428 metric tons (MT) of carbon dioxide equivalent (CO_2e) per megawatt-hour (MWh).

Model Performance

Table F.1 – PacifiCorp California Allocated GHG and Performance Against GHG Benchmarks

System Emissions from Resources Cost-Allocated to California			Forecast																	
Ln. #	Data		2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	Existing + Proxy Resources	System Generation (MWh)	57,526,425	56,603,764	55,455,453	45,186,494	44,799,421	43,102,767	43,398,652	43,833,557	43,470,967	44,394,903	45,252,931	46,189,924	44,748,749	45,505,230	45,386,515	47,011,993	45,851,924	46,600,933	48,628,939
2		System Emissions (MT CO2e)	26,391,265	25,194,794	24,760,060	19,379,379	16,846,989	15,655,479	15,947,934	16,088,916	16,004,359	15,470,019	16,444,255	16,057,613	15,368,438	14,956,701	16,027,285	17,022,497	18,056,429	18,222,066	19,579,263
3	Market Purchases	Market Purchases (MWh)	2,334,020	2,133,651	2,855,805	3,991,616	4,020,085	3,610,966	3,812,648	3,696,065	4,021,894	3,994,242	4,298,179	4,382,719	4,521,036	4,816,304	6,080,378	6,176,692	6,501,933	7,296,129	6,852,212
4		Market Purchases Emissions (MT CO2e)	998,961	913,203	1,222,285	1,708,412	1,720,596	1,545,493	1,631,813	1,581,916	1,721,371	1,709,536	1,839,621	1,875,804	1,935,003	2,061,378	2,602,402	2,643,624	2,782,827	3,122,743	2,932,747
5	California Emissions Calculation	System Emission Factor (MT CO2e/MWh)	0.4576	0.4445	0.4456	0.4288	0.3803	0.3682	0.3724	0.3718	0.3732	0.3550	0.3690	0.3546	0.3512	0.3382	0.3620	0.3697	0.3980	0.3960	0.4058
6		Retail Sales - Post DSM (MWh)	748,032	743,876	735,509	729,360	723,256	718,821	711,491	704,004	698,072	695,426	693,466	691,624	690,314	691,682	688,973	690,218	689,694	691,958	690,755
7		Retail Sale + 2% Transmission Loss	762,992	758,754	750,219	743,948	737,721	733,197	725,720	718,084	712,033	709,334	707,335	705,456	704,120	705,515	702,752	704,022	703,488	705,798	704,570
8		California In State Generation (MWh)	43,656	43,743	43,656	30,624	30,624	30,689	30,624	30,624	30,624	30,623	30,559	30,559	30,559	30,623	30,349	30,349	30,349	30,413	30,349
9		California Allocated Emissions (MT CO2e)	329,145	317,813	314,831	305,876	268,931	258,678	258,828	255,588	254,322	240,962	249,724	239,323	236,553	228,239	243,393	249,086	267,940	267,472	273,572
10		California Allocated Emissions (MMT CO2e)	**0.329**	**0.318**	**0.315**	**0.306**	**0.269**	**0.259**	**0.259**	**0.256**	**0.254**	**0.241**	**0.250**	**0.239**	**0.237**	**0.228**	**0.243**	**0.249**	**0.268**	**0.267**	**0.274**
11	**GHG Emission Target (MMT)**					**0.209**					**0.175**					**0.126**					**0.065**

CO2 emissions for market purchases are calculated using CARB default emission factor 0.428 MTCO2e/MWh

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As shown above in Table F.1, the results of PacifiCorp's modeling indicate that emissions from the preferred portfolio in the 2025 IRP Update are forecasted to exceed each of PacifiCorp's four individual greenhouse gas (GHG) benchmarks established by the January 16, 2026 Administrative Law Judge Ruling in Rulemaking R.25-06-019.

These exceedances are primarily driven by two key modeling assumptions that remain unchanged from the 2025 IRP. First, the 2025 IRP Update preferred portfolio assumes the continued availability of coal-fired resources serving California retail load through the end of the planning horizon in 2045. The persistence of coal generation in the California resource mix results in sustained emissions associated with imported power used to serve California retail sales. Second, the 2025 IRP Update preferred portfolio includes the addition of new natural gas-fired generation beginning in 2036 allocated to Utah, Idaho, Wyoming and California customers to support system reliability and operational needs. The introduction of these new gas-fired resources increases forecasted emissions in the latter portion of the planning horizon, further contributing to the modeled exceedance of California GHG benchmarks.

Together, these assumptions reflect reliability-driven resource planning considerations within the 2025 IRP Update preferred portfolio without regard for California GHG benchmarks, resulting in forecasted emissions levels that exceed the applicable GHG benchmarks over the planning horizon. PacifiCorp will consider modeling a portfolio that assumes different resource allocation scenarios and will present an approach that achieves compliance with the California GHG benchmarks for the 2024-2026 California IRP Cycle filing in proceeding R.25-06-019, due August 10, 2026.

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APPENDIX G – STAKEHOLDER FEEDBACK

Introduction

PacifiCorp thanks the many stakeholders and regulators who continue to participate thoughtfully in the 2025 IRP dockets, the 2027 IRP planning cycle and the overlapping 2025 IRP Update proceedings.

Since the inception of the 2027 IRP public input meeting series on October 1, 2025, PacifiCorp has received and considered 21 stakeholder feedback forms, and published replies to its IRP website for public access.[1] Recognizing that these 21 forms represent a continuing dialogue with stakeholders that bridges the 2025 IRP, this 2025 IRP Update, and the 2027 IRP, these new forms are presented for reference as part of this appendix. Information collected has been used to inform the 2025 IRP Update, including feedback related to process improvements and input assumptions, as well as responding directly to stakeholder questions.

While not detailed here, PacifiCorp notes the importance of additional feedback via stakeholder requested meetings, technical conferences, open regulatory meetings, and the hundreds of formal data requests submitted into jurisdictional dockets. All these channels of engagement are highly valued in the totality of PacifiCorp's IRP process.

Footnote references to stakeholder feedback are also included in the chapters and appendices of the 2025 IRP Update where relevant, a practice started in the 2025 IRP.[2] Expanding on the advancements made in the 2025 IRP, this Update also includes additional narrative derived from submitted stakeholder feedback forms and PacifiCorp's responses. The 2027 IRP is anticipated to continue evolving in this direction, improving on the integration of feedback in the documents itself.

Public Input Meetings

The implementation of expanding regulatory requirements pulled the 2027 IRP public input meeting series forward by three additional months, from a January kickoff to an October kickoff. This acceleration and expansion of the 2027 IRP schedule means that stakeholder meetings have been occurring throughout the development of the 2025 IRP Update. PacifiCorp has taken advantage of this change to include the 2025 IRP Update in discussion regarding the development of inputs and assumptions. In this sense, the 2025 IRP Update is, more than updates in the past, a truly integrated milestone in the full IRP development process.

[1] Stakeholder Feedback
[2] Refer to 2025 IRP Appendix M.

This opportunity has also encouraged PacifiCorp to provide a draft of the 2025 IRP Update two months ahead of its distribution, which is another unprecedented opportunity for stakeholder participation.

While these should be viewed as generally positive developments, PacifiCorp is mindful of the potential pitfalls of both schedule acceleration and scope expansion in a document that used to be a much simpler and pointed exercise. There are deep concerns that further pressures could force increasingly overlapping reporting requirements where there is no resolution to one process before the next, dependent process must begin. PacifiCorp has taken measured steps to ensure that all requirements can be met, with eye to managing the scope and integrity of its integrated resource planning processes.

Table G.1 reports the topics thus far covered in the 2027 IRP public input meeting series leading up to publication of the 2025 IRP Update. While it is not possible to cover all topics of a two-year process in the first five months, the topics have been extensive and have included presentations by more than a dozen PacifiCorp subject matter experts.

Table G.1 – 2025 IRP Update / 2027 IRP Public Meeting Topics

2025	2026
October 1, 2025	January 28-29, 2026 (2 day)
Introductions	Follow-up Discussion
2025 IRP Filing Status	Emissions Reporting
2025 IRP Update	DEQ Methodology
2027 IRP Overview	Resource Adequacy
Modeling Strategy	Large-Meter Load Challenges ad Modeling Plan
Demand-side Resource Planning	Transmission Notifications
Supply-Side Resource Development	B2H Sale-leaseback
Stakeholder Feedback	Demand Response Optimal Time Rewards
December 17, 2025	Stakeholder Feedback
Follow-up Discussion, Feedback	Draft 2025 IRP Updates
Supply-side Resources	Modeling tests and updates
Modeling and Assumptions	Integration and Allocation
Inputs: Load, Price, QFs	Indicative Portfolio
Transmission Modeling Overview	Federal Policy Updates
Grid Enhancing Technologies (GETs)	Hydro Forecast Update
CPA Update	Reliability and Resource Adequacy
Distributed Generation Study Overview	Transmission Interconnection Options
November 12, 2025	Conservation Potential Assessment
2025 IRP Status	Distributed Generation Update
Demand-Side Resources Update	Distribution System Planning
Supply-Side Resource Development	Optimization Modeling Overview
Planning Environment Updates	March 11-12, 2026 (2 day)
Modeling and Data Development	PacifiCorp and PGE Joint Announcement
Resource Adequacy	Follow-up Discussion
2025 IRP Update Assumptions	Stakeholder Feedback
Stakeholder Feedback	2025 IRP Update Status
	Renewable Portfolio Standards
	Price-Policy Scenarios
	Market Reliance and Purchase Limits Proposal
	Volatility and Stochastics
	Draft Preview 2027 IRP Studies
	Emissions Modeling
	DSM Bundling Portfolio Methodology
	Supply Side Resources - New Technology Risk

Stakeholder Feedback Form Summary

Table G.2 below summarizes the publicly available stakeholder feedback forms and PacifiCorp responses relevant to the 2025 IRP Update/2027 IRP public input meetings.

Table G.2 – Stakeholder Feedback Form Summary

SFF #	Request Topic	PacifiCorp Reply	Reference
2027.001 Fervo Energy (9/25/25)	Enhanced geothermal system advances	Proxy geothermal will be addressed in the public input meeting series as part of the discussion of supply-side resources.	Chapter 5; 2027 PIM #2, p.25
2027.002 SC et al. (10/30/25)	Request for summary of November 30, 2025 stakeholder meeting	Discussed jurisdictional modeling, load forecast, and Boardman to Hemingway transmission. Offered additional meeting.	Chapters 3, 6 & 8, Appendix A; 2027 PIM #2, pp.67-71
2027.003 OPUC (11/10/25)	Request the development of a pre-state-policy system baseline portfolio	An initial system resource adequacy baseline portfolio will be created..	Chapter 6; 2027 PIM #2, p.78
2027.004 SC et al. (11/10/25)	Stakeholder requests for 2025 IRP Update from 10/30/25 meeting	Please see responses to individual items in the form.	Chapter 6; 2027 PIM series
2027.005 UAE (11/12/25)	Utah SB 132 assumptions and definitions	Provided clarification and additional description of modeling for UT SB 132.	Chapter 3; 2027 PIM #2, p.79, SFF 2027.012, SFF 2027.015
2027.006 WRA (11/13/25)	Modeling of market purchases	Request is under consideration.	Chapter 5; 2027 PIM series
2027.007 OPUC (11/14/25)	Questions on PIM agenda, supply-side table, and 2025 IRP update modeling	Please see responses to individual items in the form.	2027 PIM series
2027.008 UAE et al. (11/20/25)	Recommendation regarding modeling of tax-advantaged resources	Company expectations do not align with requests at this time. The company continues to consider updates for the 2027 IRP.	Appendix H; 2027 PIM series
2027.009 SC RNW (11/25/25)	B2H, baseline and jurisdictional modeling recommendations	Please see responses to individual items in the form.	Chapters 3, 6 & 8, Appendix A; 2027 PIM #2, pp.67-71, 78
2027.011 rPlusEnergies (12/22/2025)	Pumped hydro energy storage benefits	PacifiCorp continues to seek best available data and resource opportunities.	Chapter 5; 2027 PIM #2, p.20,71, PIM #3, p.53
2027.012 IPUC (1/7/2026)	Large-meter load contracts and resource requirements, qualifying facility capacity treatment.	Description provided with a pointer to stakeholder feedback form 2027.005 UAE (11/12/25). Clarficiation of QF slide 25 from the December 2025 public input meeting.	Chapter 6; 2027 PIM #3, p.25, SFF 2027.005, SFF 2027.015
2027.013 UCE (1/14/2026)	Indicating a factual error regarding the 2025 IRP portfolio	Provided clarification of the 2025 IRP procurement window.	SFF 2027.008 UAE
2027.014 UCE (1/15/2026)	Conservation Potential Assessment topics: measures cost, forecasts, scenarios, NEIs, etc.	Please see responses to individual items in the form.	Chapter 3; 2027 IRP PIM series
2027.015 IEA (1/20/2026)	Large-meter load.	Clarifications provided.	Chapter 6; 2027 PIM #4, p.9-12, SFF 2027.005, SFF 2027.012
2027.016 UCE et al. (1/26/2026)	Request to apply system emissions methodology to each state.	Planned for the 2027 IRP	Chapter 7; 2027 PIM #4, p.6
2027.018 UCE (2/19/2026)	Request cost differential plots for sensitivites.	Planned for the 2027 IRP	Chapter 8; 2027 PIM #5, p.13
2027.019 SC et al. (2/20/2026)	Requests for senstivities and additional analysis of the 2025 IRP.	Please see responses to individual items in the form.	Chapters 6, 8, Appendix H; 2027 PIM #5, p.14, PIM series
2027.020 OPUC (2/24/2026)	2027 IRP and 2025 IRP Update, multiple topics.	Please see responses to individual items in the form.	Chapter 6, Appendix D; 2027 IRP PIM series
2027.021 UCE (3/2/2026)	Request for additional 2027 IRP DSM study.	PacifiCorp intends to provide an additional study.	2027 IRP PIM series

Additional Studies Requested

While not every request or analytical requirement needs to be specifically met with a PLEXOS model run, PacifiCorp is open to performing additional modeling and analysis. Study requests are addressed in integrated resource planning as time and modeling capabilities allow, and in response to new requirements.

Requests in the 2027 IRP public input meeting series so far include requests for additional large-meter load studies, a B2H redirects counterfactual, an increased DSM study, a resumption of Federal renewable tax credits study, and a systemwide resource adequacy study. Of these, the 2025 IRP Update includes a B2H counterfactual and Federal tax credit sensitivities in Chapter 8, and a

systemwide resource adequacy study as part of preferred portfolio development in Chapter 7. Additional large-meter load studies are planned for the 2027 IRP.

Published Stakeholder Feedback Forms

Feedback forms and PacifiCorp's responses for the 2025 IRP Update and 2027 IRP development cycle are available at the following link:

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

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APPENDIX H – TAX-ADVANTAGED PROCUREMENT EVALUATION

On October 17, 2025, the Public Service Commission of Utah issued an order regarding Utah Clean Energy's (UCE) Request for Expedited Investigatory Docket and Agency Action.[1] The order states the following:

> UCE's Request is denied, and the PSC gives notice it will take no further action in this docket. The PSC directs RMP to include a detailed explanation in its next IRP Update of the analysis and actions it undertook to evaluate and pursue any opportunities to procure needed resources that qualified for the expiring tax credits.

In response to the order, PacifiCorp provides this appendix detailing its procurement actions and evaluation results

Company Actions

Since the filing of the 2025 IRP, PacifiCorp has conducted two requests for proposals (RFPs) seeking more than 4000 megawatts (MW) of generation and 2000 MW of storage capacity and participated in the contracting of resources for the Utah Renewable Communities RFP[2] and has procured resources for large-load customers. The pricing offered by third-party developers in these resource acquisition efforts is not aligned with the proxy resource costs used in the 2025 IRP. Simply put, even if resources offered to PacifiCorp have been inclusive of federal tax credit benefits, the resource costs are still higher than publicly available proxy resource cost forecasts.

It should be noted that PacifiCorp is not developing company-owned assets at this time due to financial challenges associated with ongoing litigation and implementation of prudent cash management practices. Consequently, PacifiCorp has not offered benchmark bids in the recent RFP and has no cost estimates to provide analysis for company-developed resources.

Evaluation Results

UCE expressed concern that PacifiCorp has not used "an appropriate projection of tax-advantaged renewable and storage project build costs."[3] The company posits that its analysis in the 2025 IRP aligned with a realistic assessment of potential tax-advantaged resources given then-current federal policy. In response to stakeholder requests, PacifiCorp used the National Renewable Energy Lab's 2024 Annual Technology Baseline as the basis for proxy resource costs in the 2025 IRP. In the 2025 IRP, PacifiCorp did not identify a meaningful resource need for the Utah/Idaho/Wyoming/California (UIWC) jurisdiction. As a result, PacifiCorp did not issue an RFP for UIWC.

[1] https://pscdocs.utah.gov/electric/25docs/2503552/3423362503552o10-17-2025.pdf
[2] See Docket No: 24-035-55 | Public Service Commission
[3] See Appendix G, stakeholder feedback form #8 (UCE)

Subsequent to the filing of the 2025 IRP, Congress passed H.R.1 on July 4, phasing out tax credits for new wind and solar resources. On August 29, 2025, UCE filed its Request for Expedited Investigatory Docket and Agency Action. UCE argued that the passage of H.R.1 created a time-limited opportunity to procure tax-advantaged resources. PacifiCorp already had active RFPs in Oregon and Washington, allowing it to assess the current costs of new wind and solar resources.

The 2025 IRP modeled tax credit eligibility for proxy wind and solar resources. The 2025 IRP Update removes tax credit eligibility for proxy wind and solar resources to reflect the passage of H.R. 1. Both the 2025 IRP and the 2025 IRP Update use the 2024 Annual Technology Baseline as the basis for proxy resource costs. The 2025 IRP Update continues to represent a realistic assessment of resource costs as observed under current conditions, aligning with all known changes in the planning environment as described in Chapter 3. At the same time, the company has consistently stated that in addition to its own efforts and information gathered from the market in multiple current and distinct RFPs, PacifiCorp welcomes all opportunities that are competitively priced.

The following represents PacifiCorp's current status of evaluation for the potential of tax-advantaged resources. The proxy resource costs are presented in the fifth column of Table H.1 are inclusive of production tax credit assumptions that were current at the time of filing the 2025 IRP. Bid costs are depicted in the fourth column of Table H.1 represent actual resource costs bid into PacifiCorp's resource acquisition processes for the same general resource type and location. No bids received have been as cost-effective as proxy resource costs, inclusive of PTCs modeled in the 2025 IRP. This includes bids that have indicated to PacifiCorp that they expect to qualify for federal tax credits. Because PacifiCorp is only evaluating power purchase agreements, the value of the production tax credit is not passed directly to PacifiCorp customers.

Table H.1 shows that bid prices generally exceed the 2025 IRP proxy resource costs.

BEGIN HIGHLY CONFIDENTIAL

END HIGHLY CONFIDENTIAL

Z – ACRONYMS AND DEFINITIONS

AB = Assembly Bill

AC = alternating current

ACE = Affordable Clean Energy Rule

ACE = Area Control Error

AEG = applied energy group

AFSL = average feet (above) sea level

AFUDC = allowance for funds used during construction

AGC = Automatic Generation Control

AH = Ampere hour

A/m = Amperes per Meter

AMI = Advance Metering Infrastructure

AMR = Automated Meter Reading

ARO = asset retirement obligation

ATC = Available Transmission Capacity (Available Transfer Capacity?)

AVR = Automatic Voltage Regulator

AWEA = American Wind Energy Association

BA – Balancing Authority

BAA = Balancing Authority Area

BART = Best Available Retrofit Technology

BCF/D = billion cubic feet per day

BES = Bulk Electric System

BLM = Bureau of Land Management

BMcD = Burns and McDonnell

BPA = Bonneville Power Administration

BSER = best system of emission reduction

Btu = British thermal unit

CAES = compressed air energy storage

CAGR = compounded annual average growth rate

CAIDI = Customer Average Interruption Duration Index

CAISO = California Independent System Operator

CAP = Community Action Program

CARB = California Air Resources Board

CARI = Control Area Reliability Issues

CCCT = Combined Cycle Combustion Turbine

CCGT = Combined Cycle Gas Turbine

CCR = coal combustion residual

CCS = carbon capture and sequestration / Utah Committee of Consumer Services

CCUS = carbon capture utilization and sequestration; deprecated acronym for CCS

CEC = California Energy Commission

CETA = Clean Energy Transformation Act

CF = capacity factor

CFL = Compact Fluorescent Light Bulb

CIPS = Critical Infrastructure Protection Standards

CIS = Corporate Information Security

CO = carbon monoxide

CO_2 = carbon dioxide

Cogen = Cogeneration

Committed: Something (such as load) that PacifiCorp Energy Supply Management is obligated to serve.

COMPASS = Coordinated Outage Management Planning and Scheduling System?

CPA = Conservation Potential Assessment

CPU = Clark Public Utilities / cost per unit

CPUC = California Public Utilities Commission

CREA = Columbia Rural Electric Association

CSP = concentrated solar power

CTG = Combustion Turbine Generator

CUB = (Oregon) Citizen's Utility Board

DC = direct current

DF = duct firing

DG = Distributed Generation

DOE = Department of Energy

DPU = Utah Division of Public Utilities / Distribution Protection Unit (relay)

DR = Demand Response

DRA = Division of Ratepayer Advocates

DSM = demand-side management

EBIT = Earnings before Interest and Taxes

EDAM = extended day-ahead market

EE = Energy Efficiency

EEI = Edison Electric Institute

EIA = Energy Information Administration

EIM = Energy Imbalance Market

ELCC = Effective Load Carrying Capacity

EPA = Environmental Protection Agency

EPC = engineering, procurement, and construction

EPM = Energy Portfolio Management System

ERC = emission rate credit

ETO = Energy Trust of Oregon

EUBA = Electric Utility Benchmarking Association

EUI = Energy Utilization Index

EUL = effective useful life

EV = Electric Vehicle

FCC = Federal Communications Commission

FCRPS = Federal Columbia River Power System

FERC = Federal Energy Regulatory Commission

FIP = federal implementation plan

FIT = Feed-In Tariff

FLPMA = Federal Land Policy Management Ace

FOTs = Front Office Transactions

FRAC = Flexible Resource Adequacy Capacity

GAAP = Generally Accepted Accounting Principles

GBP = Great Britain Pound

GE = General Electric

GFCI = Ground Fault Circuit Interrupter

GHG = Greenhouse Gas

GIC = Generation Interconnection Contract

GIS = Geographic Information System

GPS = Global Positioning System

GRC = General Rate Case

GRID = Generation and Regulation Decision Model (used for net power cost pricing calc and QF avoided cost calc)

GT = Gas Turbine

GW = Gigawatt

GWh = gigawatt-hours (gigawatt)

H = Hour

HB = House Bill

HCC = Hydro Control Center

HRSG = Heat Recovery Steam Generator

HVAC = heating, ventilation, and air conditioning

Hz = Hertz

IBEW = International Brotherhood of Electrical Workers

IC = internal combustion

ICE = Intercontinental Exchange

IECC = International Energy Conservation Code

IEEE = Institute of Electrical and Electronic Engineers

IGCC = integrated gasification combined cycle

IHS = Information Handling Services

ILR = Inverter Loading Ratio

IOU = Investor Owned Utility

IPC = Idaho Power Company

IPP = Independent Power Producer

IPOC = Idaho Power Company

IPUC = Idaho Public Utility Commission

IRA = Inflation Reduction Act

IRP = Integrated Resource Plan

IS = Information Systems

ISO = Independent System Operator

IT = Information Technology

ITC = Investment Tax Credit

K = kilo (thousand)

Kv = kiloVolt

kW = kilowatt

kWh = kilowatt-hour

kW-yr = Kilowatt-Year

kV = kilovolt

kVa = kilovolt-ampere

kVAr = kilovolt-ampere-reactive

kVArh = kilovolt-ampere-reactive-hour

Large Load (also "large-meter load"): Large Load is defined by state regulation in Oregon, Utah and Wyoming. Where not defined, PacifiCorp assumes the smallest statutory definition of a single load service request of 20 megawatts or greater.

Lb = Pound

LCOE = Levelized Cost of Energy

LED = light emitting diode

Li-Ion = lithium-ion battery

Lm = lumens

LNG = Liquefied Natural Gas

LOLH = loss of load hour

LOLP = loss of load probability

LRA = Local Regulatory Authority

LSE = load serving entities

MATS = Mercury and Air Toxics Standards

MMBpd = Million barrels of oil per day

MMBtu = Million British thermal units

MSP = Multi-State Process

MVA = megavolt-ampere

MVAr = megavolt-ampere-reactive

MVA LTC = megavolt-ampere, load tap changing

MW = Megawatt

MWh = megawatt hour

$MWh = dollars per megawatt hour

NAAQS = National Ambient Air Quality Standards

NAPEE = National Action Plan for Energy-Efficiency

NCM = nickel cobalt manganese (sub-chemistry of Li-Ion)

NEEA = Northwest Energy Efficiency Alliance

NEEP = Northeast Energy Efficiency Partnerships

NEMA = National Electrical Manufacturer's Association

NEMS = National Energy Modeling System

NERC = North American Electric Reliability Corporation

NH_3 = Ammonia

NOAAF = National Oceanic and Atmospheric Administration Fisheries

NRC = Nuclear Regulatory Commission

NREL = National Renewable Energy Laboratory

NOx = Nitrogen Oxides

NPV = net present value

NQC = Net Qualifying Capacity

NSPS = new source performance standards

NTTG = Northern Tier Transmission Group

NWEC = NW Energy Coalition

NWPCC = Northwest Power and Conservation Council

O&M = operations and maintenance

OAR = Oregon Administrative Rules

OASIS = Open Access Same Time Information System

OATT = Open Access Transmission Tariff

ODOE = Oregon Department of Energy

ODOT = Oregon Department of Transportation

OE = Owner's Engineer

OEM = Original Equipment Manufacturer

OFPC = Official Forward Price

OMS = Outage Management System

OPUC = Oregon Public Utility Commission

ORS = Oregon Revised Statutes

OTR = Ozone Transport Rule

PAC = PacifiCorp

PACE = PacifiCorp East?

PaR = Planning and Risk Model

PC = pulverized coal

PCB = Polychlorinated Biphenyls

PC CCS = pulverized coal equipped with carbon capture and sequestration

PDDRR = Partial displacement differential revenue requirement methodology (OR QF)

PG&E = Pacific Gas & Electric

PGE = Portland General Electric

PHES = pumped hydro energy storage

PJM = no definition

PM = particulate matter

$PM_{2.5}$ = Particulate Matter 2.5 microns and larger

PM_{10} = Particulate Matter 10 microns and larger

PNUCC = Pacific Northwest Utility Coordinating Council

POU = Publicly Owned Utility

Portfolio: a coordinated set of resources (including generation, demand-side management, storage, purchases and transmission) which meet all modeled requirements for a given set of conditions. Portfolios result from running models which employ advanced math to make optimal resource selections aligned with the specified conditions.

PP = Pacific Power

PPA = Power Purchase Agreement

Ppb = parts per billion

PP&L = Pacific Power & Light Co.

ppmvd@15%02 = parts per million, dry-volumetric basis, corrected to 15% Oxygen (O_2)

Preferred portfolio: the optimal portfolio, selected from among eligible portfolios, based on cost and risk metrics.

PRM = Planning Reserve Margin

PSC = Public Service Commission

PSE = Purchasing-Selling Entity

Psia = Pounds per Square Inch-Absolute

PTC = Production tax credit

PTO = Participating Transmission Owner

PTP = point to point

PUC = Public Utility Commission

PURPA = Public Utility Regulatory Policies Act

PV = photovoltaic

PVRR(d) = present value revenue requirement (delta)

PWC = PricewaterhouseCoopers

QC = Qualifying Capacity

RA = Resource Adequacy

RCRA = Resource Conservation and Recovery Act

RCW = Revised Code of Washington

REA = Rural Electrical Administration / Rural Electrification Administration

REC = renewable energy credit (certificate)

RFI = request for information

RFM = Rate Forecasting Model

RFP = Request for Proposal

RH = Relative humidity

RICE = Reciprocating Internal Combustion Engine

RMP = Rocky Mountain Power

RPS = Renewable Portfolio Standard

RTO = Regional Transmission Organization

RTF = Regional Technical Forum

RTP = real-time pricing

RVOS = Resource Value of Solar

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

SB = Senate Bill

SCCT = Simple Combined Cycle Turbine

SCPC = Super-critical pulverized coal

SCPPA = Southern California Public Power Authority

SCR = selective catalytic reduction system

SEC = Securities and Exchange Commission

SEEM = Simple Energy Enthalpy Model

SEPA = Solar Electric Power Association

SIP = state implementation plan

SF = Senate File

SF6 = Sulfur Hexafluoride

SNCR = selective non-catalytic reduction

SO = System Optimizer

SO_2 = Sulfur Dioxide

SO_x = Sulfur Oxide

SRSG = Southwest reserve sharing group

SSR = small-scale renewable (note SSR is not used for 'supply-side resource')

STEP = Sustainable Transportation and Energy Plan

STG = Steam turbine generator

SWEEP = Southwest Energy Efficiency Project

T&D = Transmission & Distribution

th = Therm

TPL = transmission planning assessment

UAE = Utah Association of Energy Consumers

UDOT = Utah Department of Transportation

UMPA = Utah Municipal Power Agency

UNIDO = United Nations Industrial Development Organization

UP&L = Utah Power & Light Co.

UPC = Use per Residential Customer

UCE = Utah Clean Energy

UCT = Utility Cost Test

VERs = Variable Energy Resources

V = volt

VA = Volt-ampere

VDC = Volts Direct Current

VOC = volatile organic compounds

W = Watts

WAC = Washington Administrative Code

WACC = weighted average cost of capital

WAPA = Western Area Power Administration

WCA = West Control Area

WECC = Western Electricity Coordinating Council

Wh = Watt-hour

WIEC = Wyoming Industrial Energy Council

WPSC = Wyoming Public Service Commission

WRA = Western Resource Advocates

WRAP = Western Resource Adequacy Program

WREGIS = Western Renewable Generation Information System

WSEC = Washington State Energy Code 2015

WSPP = Western Systems Power Pool

WTG = wind turbine generator

WUTC = Washington Utilities and Transmission Commission