PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

March 31, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

RE: LC 82—PacifiCorp's 2023 Integrated Resource Plan

PacifiCorp d/b/a/ Pacific Power (PacifiCorp or Company) submits for filing its 2023 Integrated Resource Plan (2023 IRP).[1] The 2023 IRP is also available electronically on PacifiCorp's IRP website, at: www.pacificorp.com/energy/integrated-resource-plan.html. PacifiCorp submits the 2023 IRP to the Public Utility Commission of Oregon (Commission) under OAR 860-027-0400. Information outlining how PacifiCorp has addressed the procedural and substantive elements of the Commission's rules is provided in Appendix B – IRP Regulatory Compliance, Tables B.2 and B.3.

The 2023 IRP is the most intricate IRP the Company has filed, encompassing hundreds of regulatory requirements from the Company's six-state service territory, as detailed in Appendix B. The Company has restructured its workpapers that support the 2023 IRP in a manner that enables the public to access more information and complies with Commission direction by designating certain information within these workpapers to be highly confidential, such as competitively sensitive, project specific data obtained from prior resource procurement processes.[2] Going beyond the direction in Order 22-128, the restructuring of the workpaper format will provide developer stakeholders access to all confidential workpapers. The Company will make the non-confidential workpapers available, via data disc, within two weeks of submitting the 2023 IRP, while the confidential and highly confidential versions will be provided no later than May 1, 2023, prior to the start of the initial 60-day preliminary comment period.[3]

PacifiCorp plans to supplement its filing with results of its 2023 IRP sensitivity studies no later than May 1, 2023. A post-IRP filing public-input meeting has been scheduled April 13, 2023 to provide an opportunity for stakeholder discussion on the organization of the preferred portfolio.

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[1] OAR 860-001-0170(2) requires that a utility provide 20 physical copies of its IRP upon filing. However, the Commission has temporarily waived this requirement. *See, In the Matter of Public Utility Commission of Oregon, Waiver of Rules to Accommodate Temporary Changes in Business Practices,* Docket No. UM 2061, Order No. 20-088 (Mar. 18, 2020).

[2] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77, Order No. 22-128 (April 25, 2022).

[3] *See* Special Public Meeting LC 82 PAC IRP and Clean Energy Plan (March 28, 2023), *available at* https://www.oregon.gov/puc/news-events/Pages/default.aspx.

Formal correspondence for this proceeding should be addressed as follows:

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It is respectfully requested that all data requests regarding this filing be addressed as follows:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
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PacifiCorp appreciates the time and effort Oregon participants have dedicated to helping the Company develop its 2023 IRP.

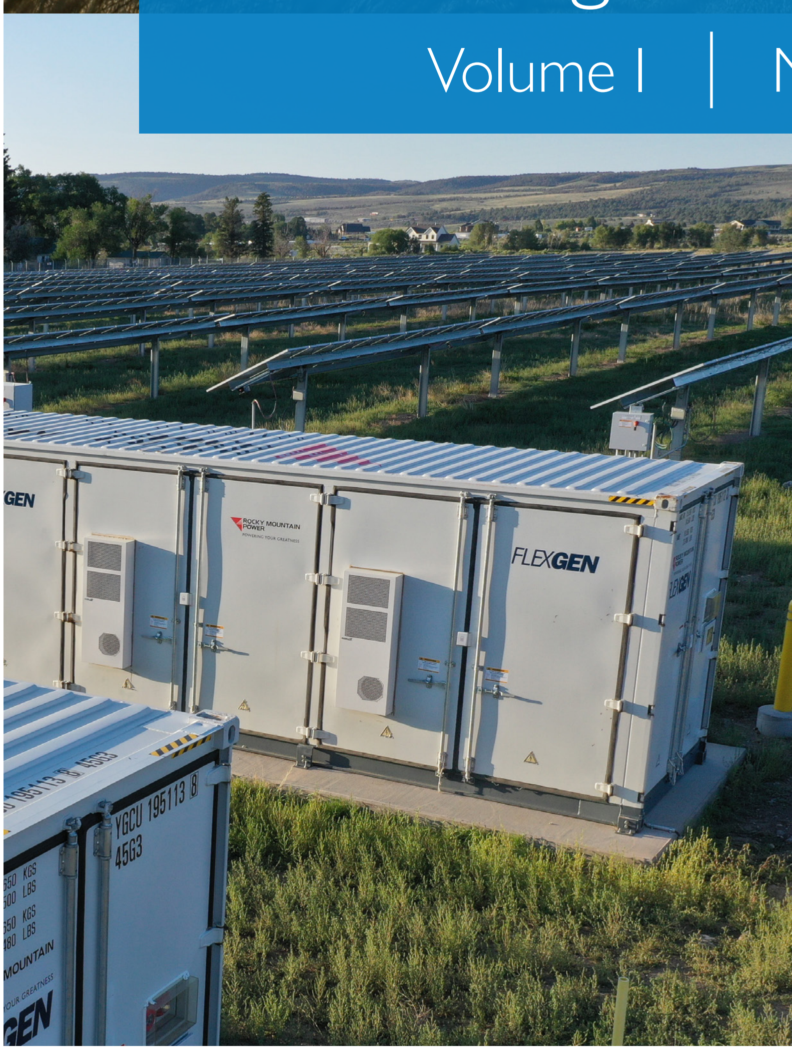
Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

cc: Service List LC 77 (without enclosures)

2023 Integrated Resource Plan

Volume I | March 31, 2023



PACIFICORP

CHAPTER 1 – EXECUTIVE SUMMARY

Delivering on our promise

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

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

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

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

CALLOUT BOX

OUR COMMITMENTS

Prioritizing savings and value for our customers

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

Expanding clean power

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

Building storage capacity

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

Investing in transmission

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

Roadmap

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

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

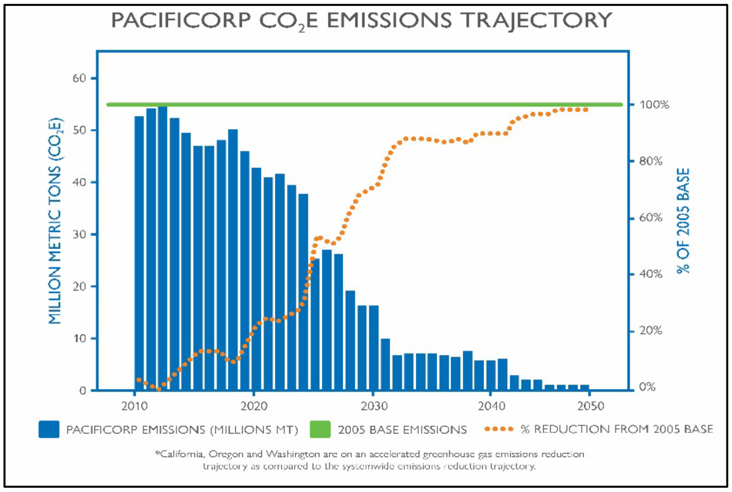
- Continue our growth toward a grid powered by clean energy:
    - 9,111 megawatts of new wind resources.
    - 8,095 megawatts of storage resources, including batteries co-located with solar generation, standalone batteries and pumped hydro storage resources.
    - 7,855 megawatts of new solar resources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

Accelerating Progress

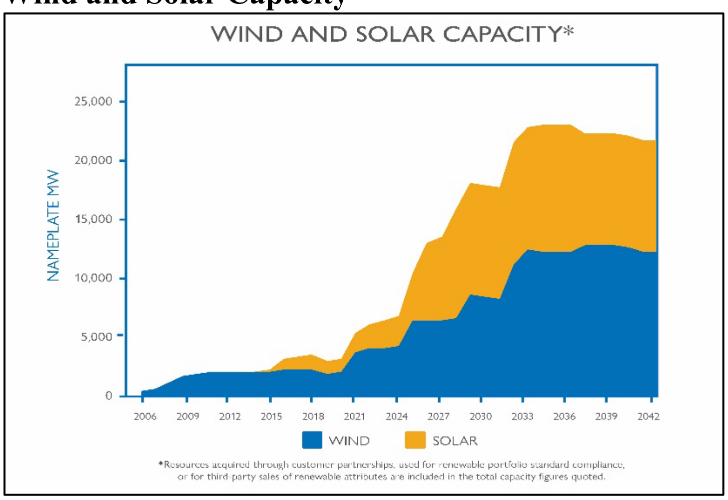
Tracking our progress

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

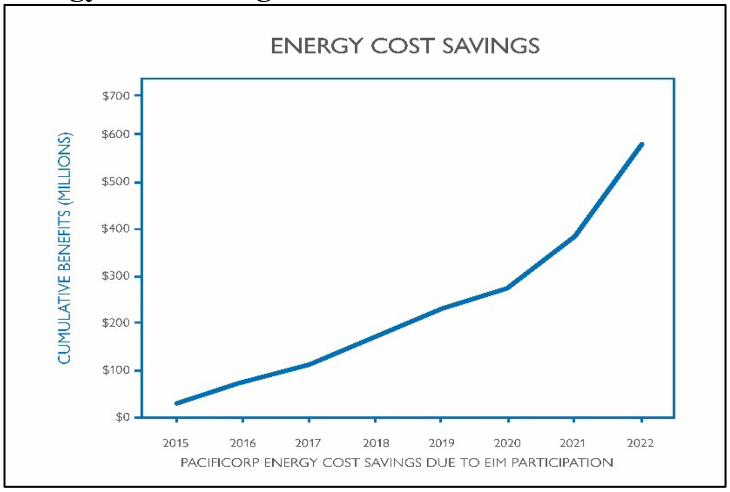
Emissions



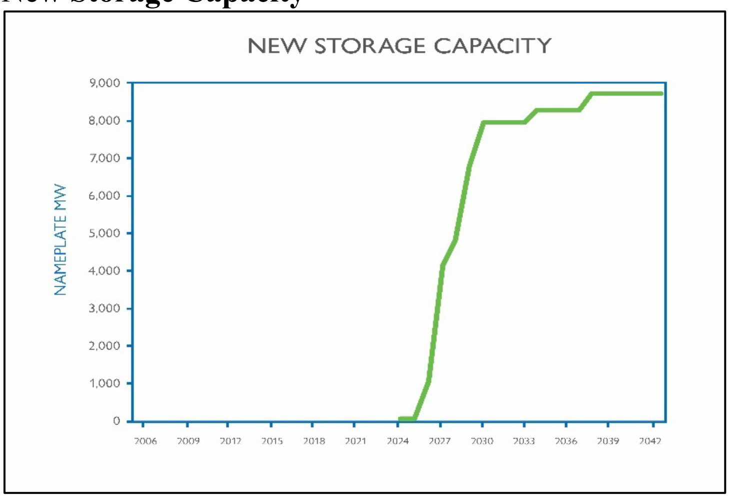
Wind and Solar Capacity



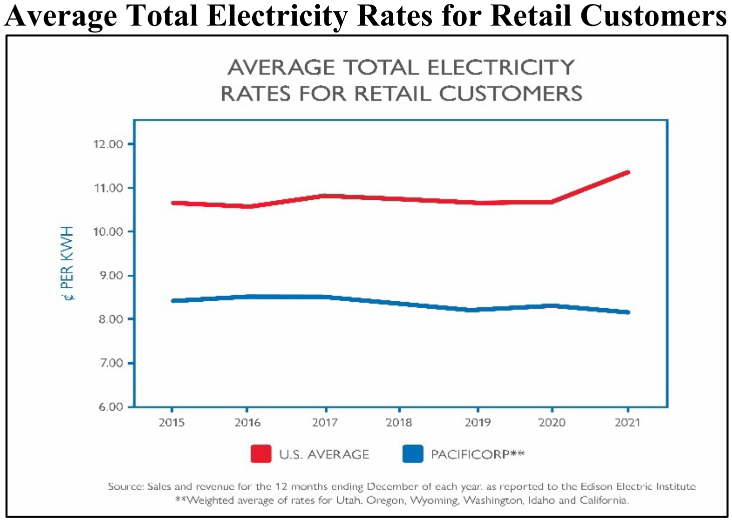
Energy Cost Savings



New Storage Capacity



Average Total Electricity Rates for Retail Customers



Changes to our portfolio

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

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

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

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

Partnerships and Innovation

Building partnerships for a thriving future

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

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

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

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

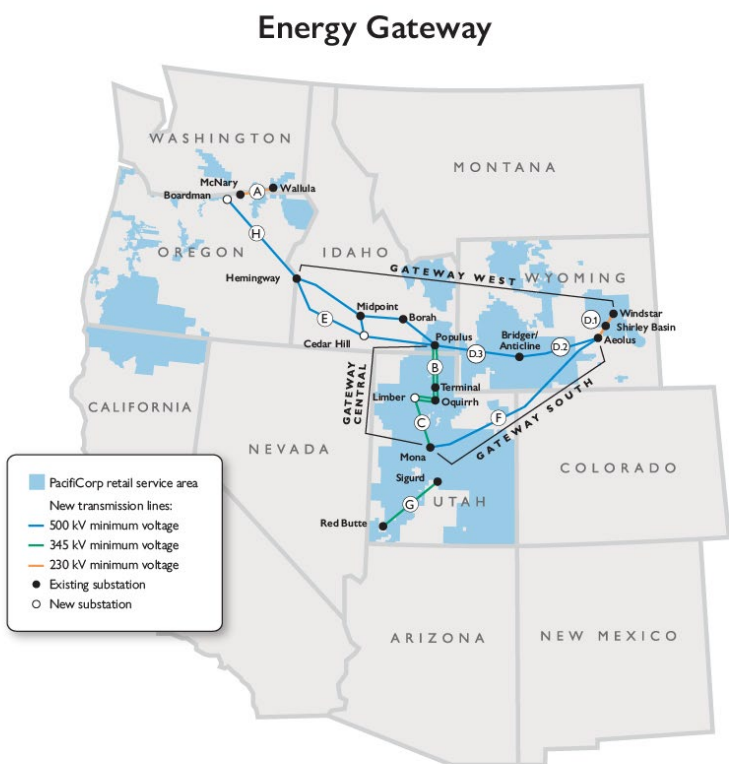
Partnering for advanced nuclear

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

Building a connected, resilient grid

Expanding transmission to connect clean energy and communities across the West

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



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

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

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

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

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

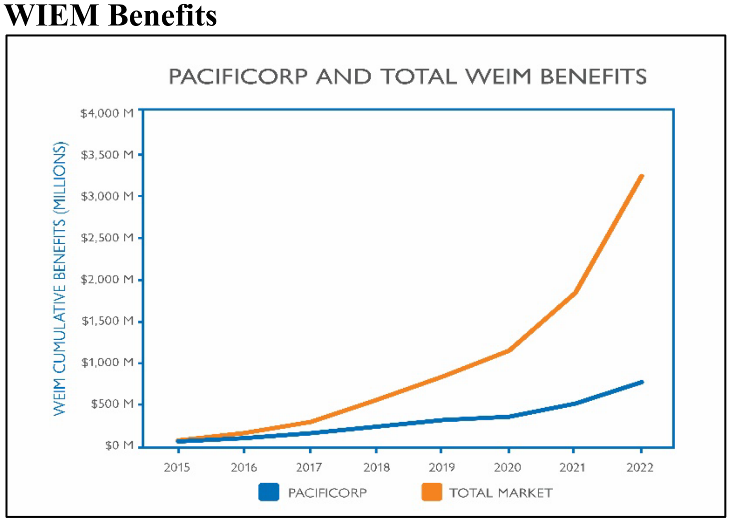
Capturing savings and delivering value

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

WESTERN ENERGY IMBALANCE MARKET

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

WIEM Benefits



EXTENDED DAY-AHEAD MARKET

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

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

Energy Efficiency/Demand response

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

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

798 megawatts of energy efficiency between 2023 and 2026
661 megawatts of demand response between 2023 and 2026

Conclusion

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

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

PacifiCorp's Integrated Resource Plan Approach

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

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

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

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

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

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

Figure 1.1 – Key Elements of PacifiCorp's 2021 IRP Approach

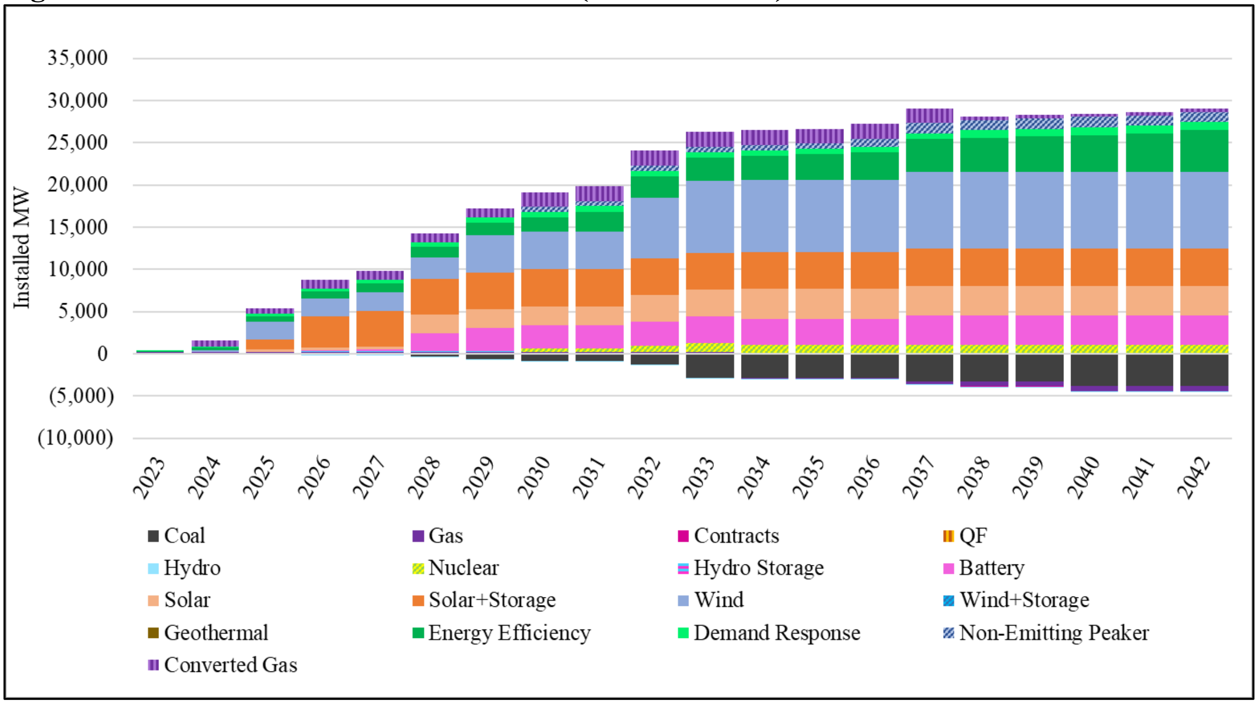
Preferred Portfolio Highlights

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

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

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

Figure 1.2 – 2021 IRP Preferred Portfolio (All Resources)



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

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

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

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

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

<table>
<tr><th>Year</th><th colspan="2">From</th><th>To</th><th>Export (MW)[1]</th><th>Import (MW)[1]</th><th>Inter-connect (MW)</th><th>Description</th></tr>
<tr><td rowspan="2">2024</td><td colspan="3">Multistate Path C Improvement</td><td>0</td><td>0</td><td>100</td><td>Path C enables Utah, Idaho, Wyoming interconnection, additional transmission options</td></tr>
<tr><td colspan="3">Within Yakima WA Transmission Area</td><td>0</td><td>0</td><td>80</td><td>Union Gap-Midway 230 kV Line and substation - Yakima, enables additional transmission options</td></tr>
<tr><td rowspan="3">2025</td><td colspan="3">Within Willamette Valley WA Transmission Area</td><td>0</td><td>0</td><td>9</td><td>Cluster 2 Area 22 - Willamette Valley, enables 9 MW of solar</td></tr>
<tr><td colspan="2">Walla Walla WA</td><td>Yakima WA</td><td>400</td><td>400</td><td>200</td><td>Walla Walla - Wine Country 230 kV line and integration, enables 200 MW of wind in 2032</td></tr>
<tr><td>GWS</td><td>Wyoming East</td><td>Clover UT</td><td>1,200</td><td>1,700</td><td>2,030</td><td>Energy Gateway South, enables 1,716 MW wind, 315 MW solar and storage, and future transmission</td></tr>
<tr><td rowspan="10">2026</td><td colspan="3">Within Borah-Populus ID Transmission Area</td><td>0</td><td>0</td><td>1,100</td><td>Cluster 2 Area 5 - Borah, enabling 1,100 MW solar and 1,100 MW storage</td></tr>
<tr><td colspan="3">Within BPA NITS (OR) Transmission Area</td><td>0</td><td>0</td><td>160</td><td>Cluster 2 Area 21 - BPA NITS, enables 160 MW storage</td></tr>
<tr><td colspan="3">Within Central Oregon Transmission Area</td><td>0</td><td>0</td><td>240</td><td>Transition Cluster Area 8 - Central Oregon, enables 200 MW solar and 200 MW storage</td></tr>
<tr><td colspan="3">Within Clover UT Transmission Area</td><td>0</td><td>0</td><td>331</td><td>TCA4: Q820 contingent facilities - Utah South, enables 300 MW solar and 300 MW storage</td></tr>
<tr><td colspan="3">Within Willamette Valley OR Transmission Area</td><td>0</td><td>0</td><td>719</td><td>Cluster 2 Area 23 - Willamette Valley, enables 474 MW solar and 474 MW storage</td></tr>
<tr><td colspan="3">Within Yakima WA Transmission Area</td><td>0</td><td>0</td><td>450</td><td>Cluster 1 Area 10 - Yakima, enables 450 MW solar and 707 MW storage</td></tr>
<tr><td rowspan="4">B2H</td><td>Borah-Populus ID</td><td>Hemingway ID</td><td>600</td><td>300</td><td>600</td><td>B2H - Idaho Power Asset Transfer, enabling 300 MW wind, 400 MW solar, 600 MW storage</td></tr>
<tr><td>Hemingway ID</td><td>Longhorn OR</td><td>818</td><td>0</td><td>0</td><td>B2H component</td></tr>
<tr><td>Longhorn OR</td><td>McNary OR</td><td>300</td><td>0</td><td>0</td><td>B2H - Longhorn Load component</td></tr>
<tr><td>Walla Walla WA</td><td>Borah ID</td><td>300</td><td>0</td><td>0</td><td>B2H - IPC PTP Eastbound component</td></tr>
</table>

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

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

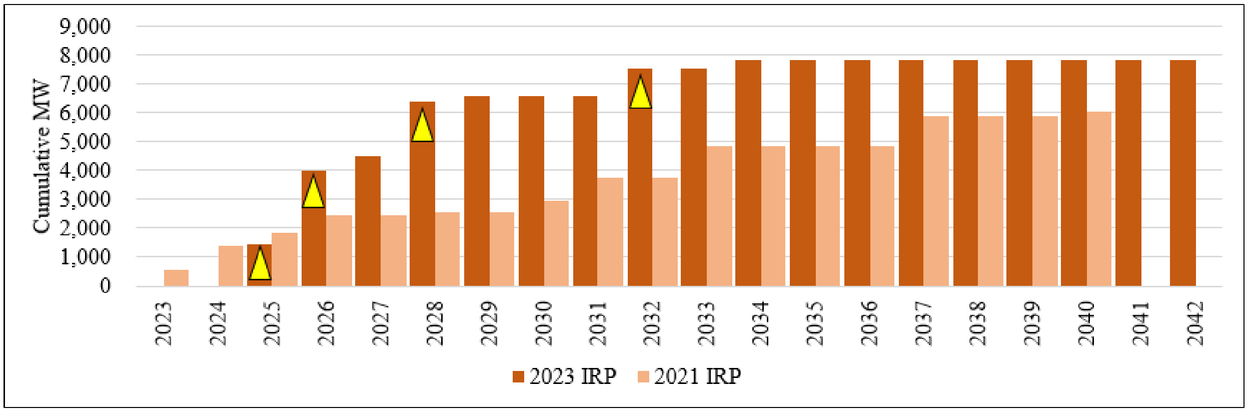
[1] TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
[2] Transmission upgrades are generally modeled as all or nothing options. These items reflect partial transmission builds, which were allowed in the second half of the 2023 IRP planning horizon, starting in 2033, so as to provide an indication of possible future outcomes.

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

New Solar Resources

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

Figure 1.3 – 2023 IRP Preferred Portfolio New Solar Capacity*

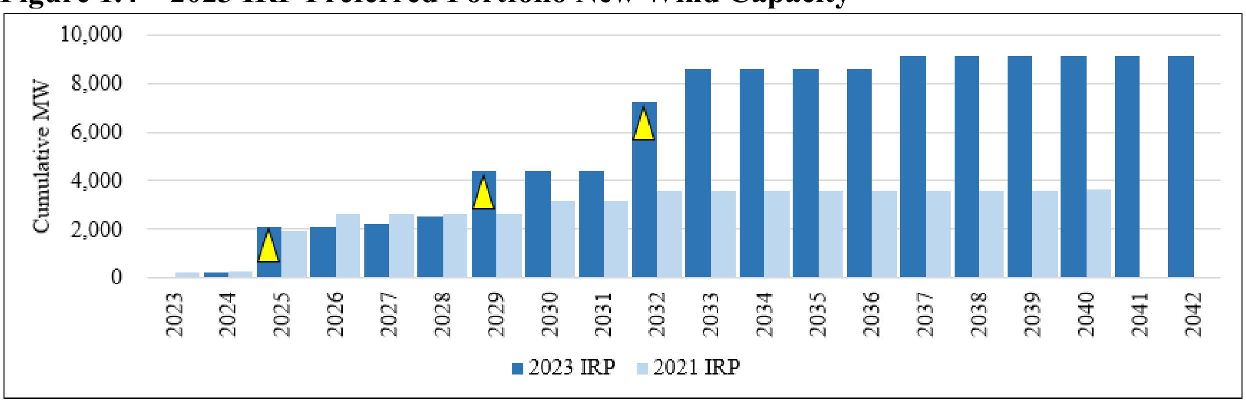


* 2023 IRP solar capacity shown in the figure includes solar resources coming via the 2020 All-Source Request for Proposals by the end of 2024. Resources are shown in the first full year of operation (the year after the year-online dates).

New Wind Resources

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

Figure 1.4 – 2023 IRP Preferred Portfolio New Wind Capacity*

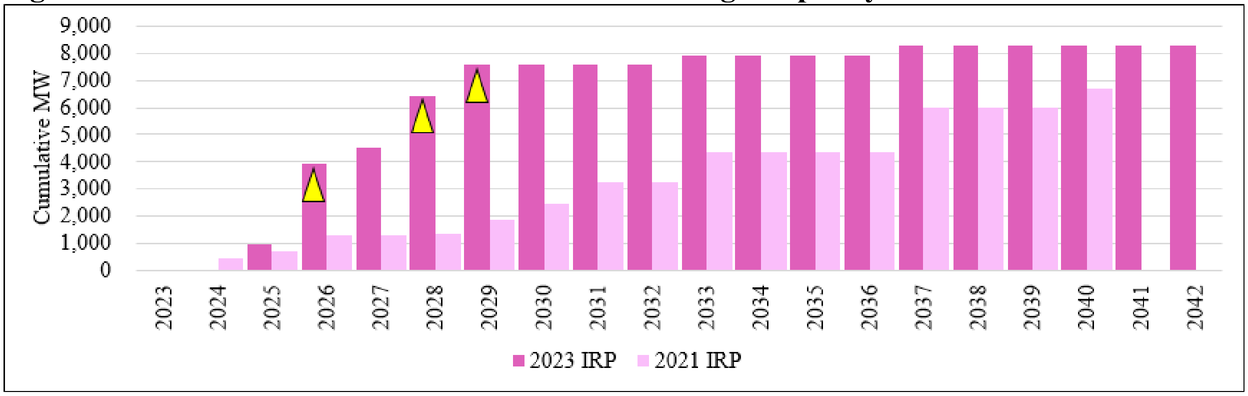


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates).

New Storage Resources

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

Figure 1.5 – 2023 IRP Preferred Portfolio New Storage Capacity*

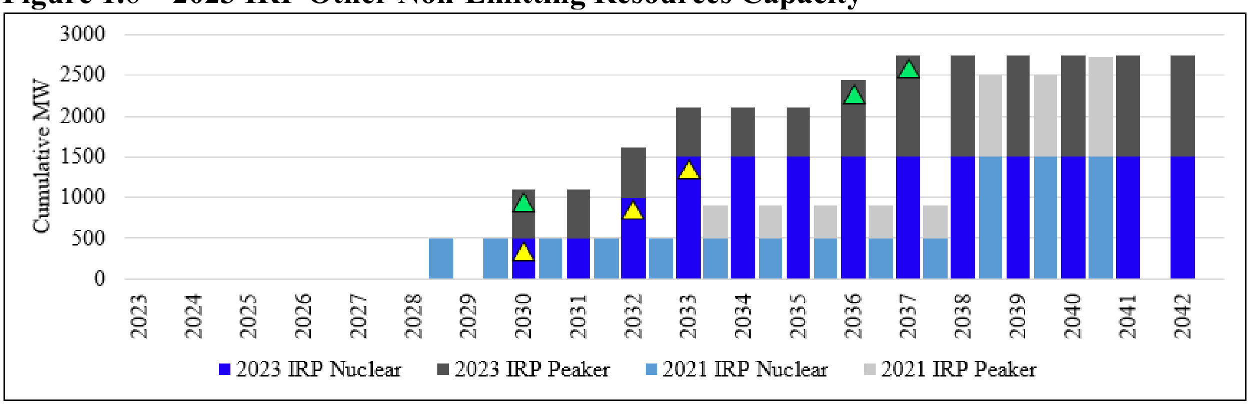


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Other Non-Emitting Resources

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

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

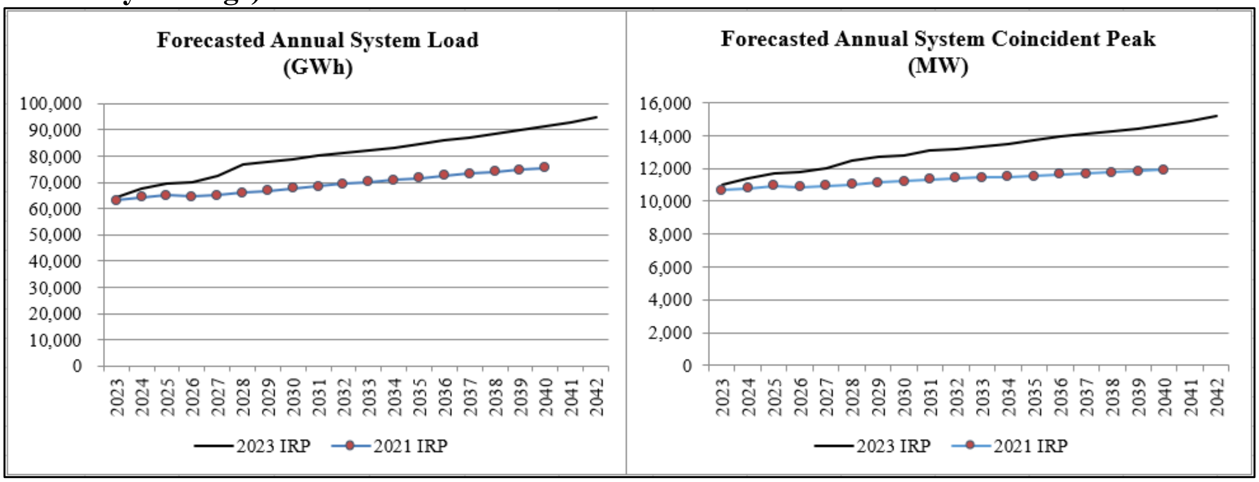


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

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

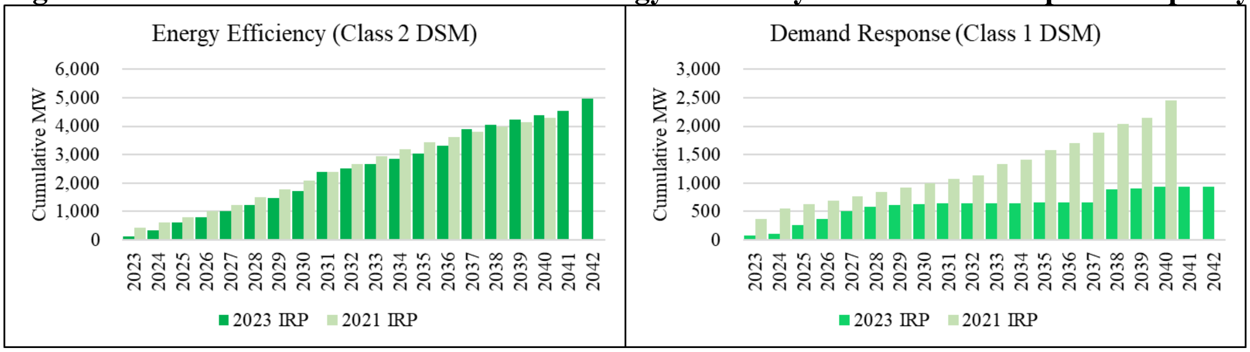
Figure 1.7 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 1.98 compares total energy efficiency capacity savings in the 2023 IRP preferred portfolio relative to the 2021 IRP preferred portfolio and includes 4,953 MW by the end of the planning period.

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

Figure 1.8 – 2021 IRP Preferred Portfolio Energy Efficiency and Demand Response Capacity



Wholesale Power Market Prices and Purchases

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

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

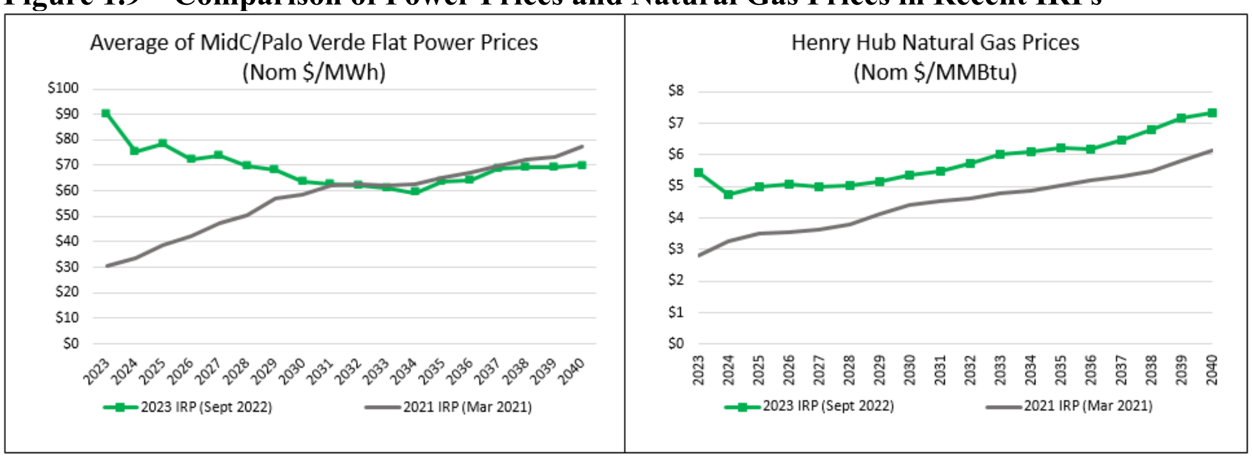
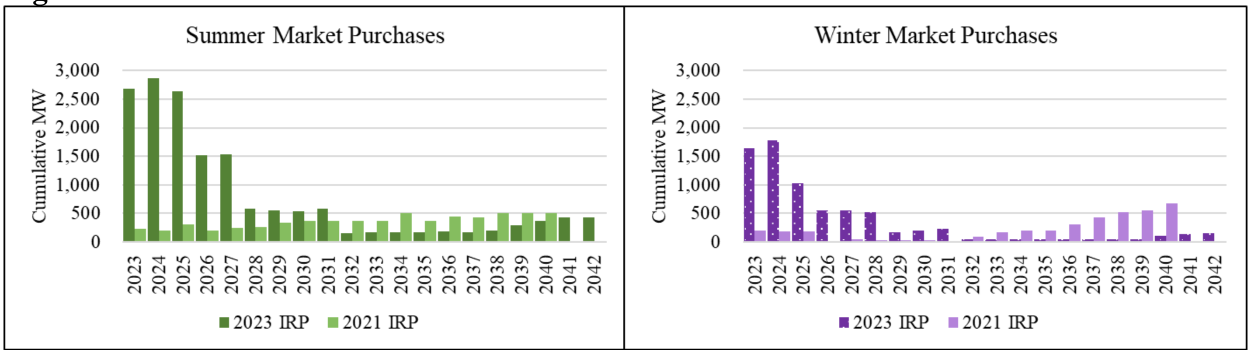


Figure 1.10, below, shows an overall increase in reliance on wholesale power market firm purchases in the 2023 IRP preferred portfolio relative to the wholesale power market purchases included in the 2021 IRP preferred portfolio. In years 2023 through 2027, the magnitude of this increase is exaggerated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

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

Figure 1.10 – 2021 IRP Preferred Portfolio Market Purchases



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

Coal and Gas Exits, Retirements, and Gas Conversions

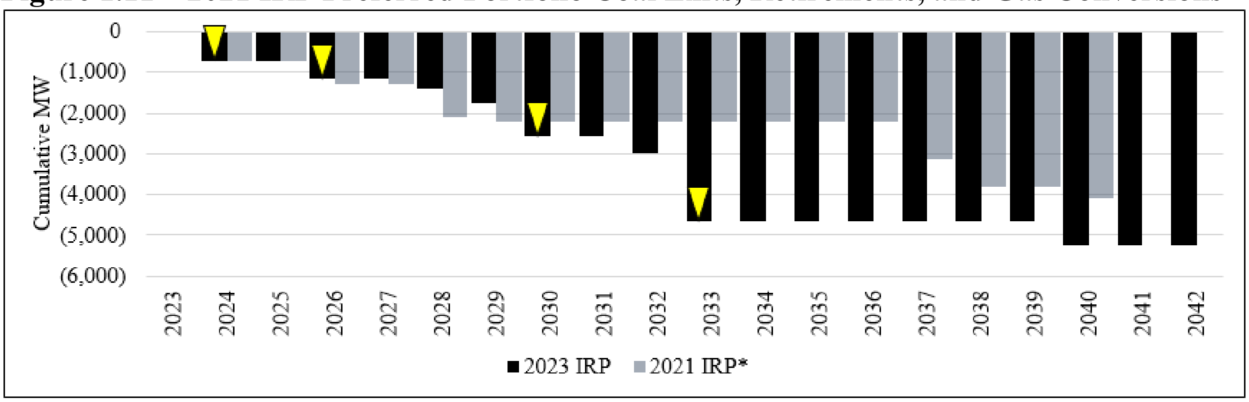
Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to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

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

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

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

Figure 1.11 – 2021 IRP Preferred Portfolio Coal Exits, Retirements, and Gas Conversions*



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

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

Carbon Dioxide Emissions

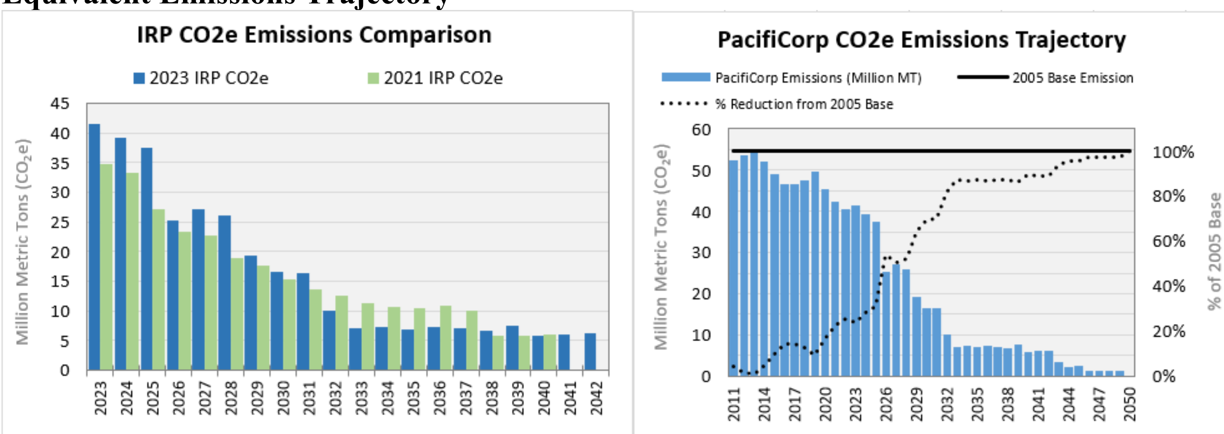
The 2023 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) and other carbon dioxide equivalent (CO_2e) emissions resulting in a measure of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

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

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

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

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



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

Renewable Portfolio Standards

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

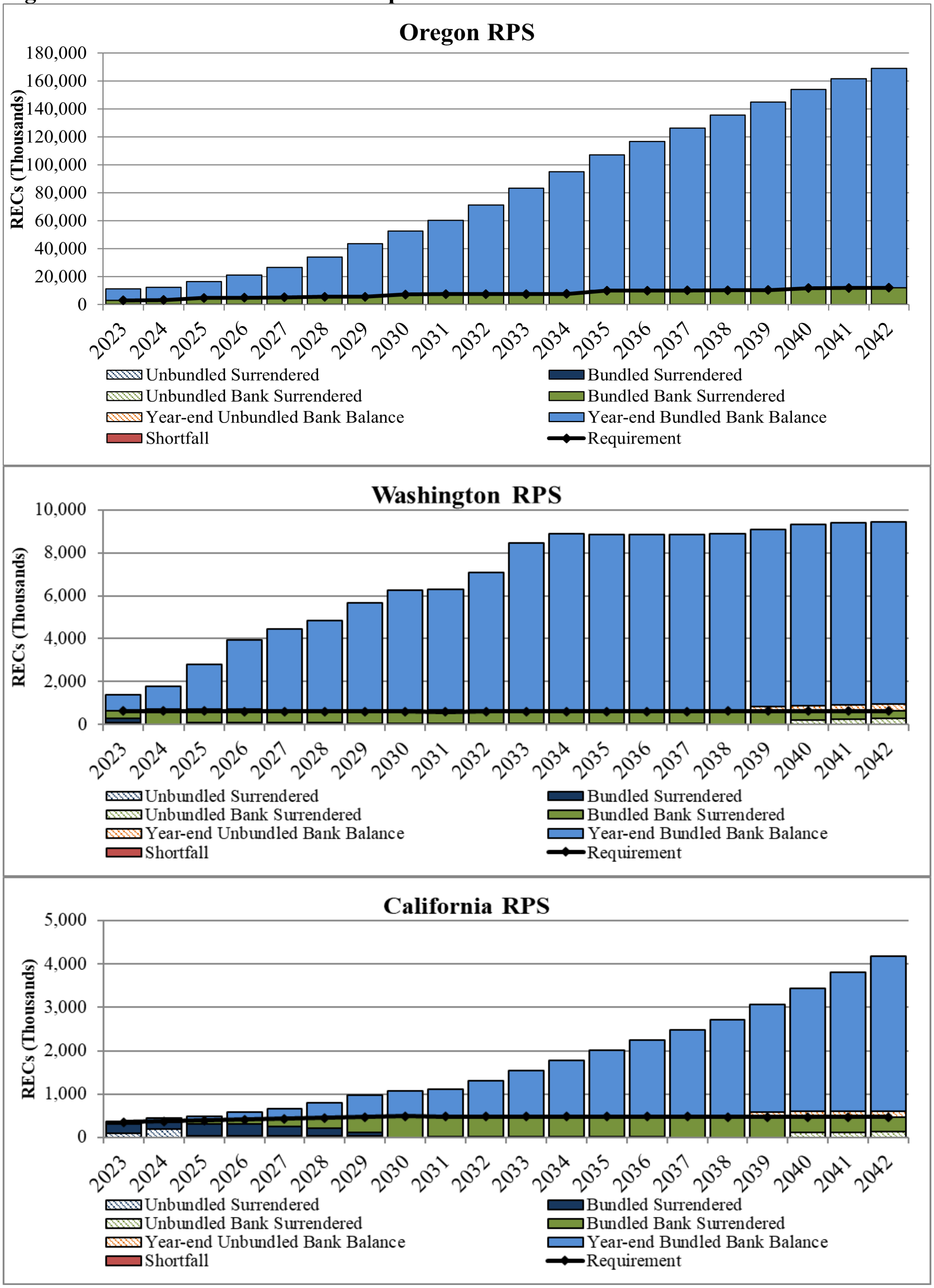
Oregon RPS compliance is achieved through 2042 with the addition of new renewable resources in the 2023 IRP preferred portfolio. Washington RPS compliance is also achieved through 2042 with the addition of new renewable resources. Under PacifiCorp's 2020 Protocol, and the

Washington Interjurisdictional Allocation Methodology, Washington receives a system share of renewable resources across PacifiCorp's system.

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

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

Figure 1.13 – Annual State RPS Compliance Forecast



2021 IRP Advancements and Supplemental Studies

IRP Advancements

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

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

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

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

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

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

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

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

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

Supplemental Studies

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

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

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

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

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

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

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

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

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

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

Action Plan

The 2023 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2023 IRP public-input process. Table 1.3 details specific 2021 IRP action items by resource category.

Table 1.3 – 2023 IRP Action Plan

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

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

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

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

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

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

<u>**Energy Efficiency Targets:**</u>

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

<table>
<tr><th>Year</th><th>Annual 1st Year Energy (GWh)</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2023</td><td>543</td><td>123</td></tr>
<tr><td>2024</td><td>551</td><td>220</td></tr>
<tr><td>2025</td><td>596</td><td>259</td></tr>
<tr><td>2026</td><td>563</td><td>197</td></tr>
</table>

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

<table>
<tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2023</td><td>72</td></tr>
<tr><td>2024</td><td>39</td></tr>
<tr><td>2025</td><td>152</td></tr>
<tr><td>2026</td><td>109</td></tr>
</table>

[1] Capacity impacts for demand response include both summer and winter impacts within a year.

[2] A portion of cost-effective demand response resources identified in the 2021 2023 preferred portfolio in 2023 for Oregon and Washington represent planned volumes expected are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources offered through approved programs. subsequently procured under the previously issued RFP in compliance with state level procurement requirements.

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

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

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

CHAPTER 2 – INTRODUCTION

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

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

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

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

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

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

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

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

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

2021 Integrated Resource Plan Components

The basic components of PacifiCorp's 2023 IRP include:

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

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

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

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

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

The Role of PacifiCorp's Integrated Resource Planning

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

Public-Input Process

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

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

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

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

CHAPTER 3 – PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

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

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

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

Introduction

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

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

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

Wholesale Electricity Markets

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

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

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

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

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

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

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

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

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

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

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

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

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

[4] 162 FERC ¶ 61,127 United States of American Federal Energy Regulatory Commission, 18 CFR Part 35 [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841] *Electric Storage Participation in Markets Operated by Regional Transmission;* Organizations and Independent System Operator (Issued February 15, 2018)

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

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

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

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

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

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

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

Power Market Prices

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

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

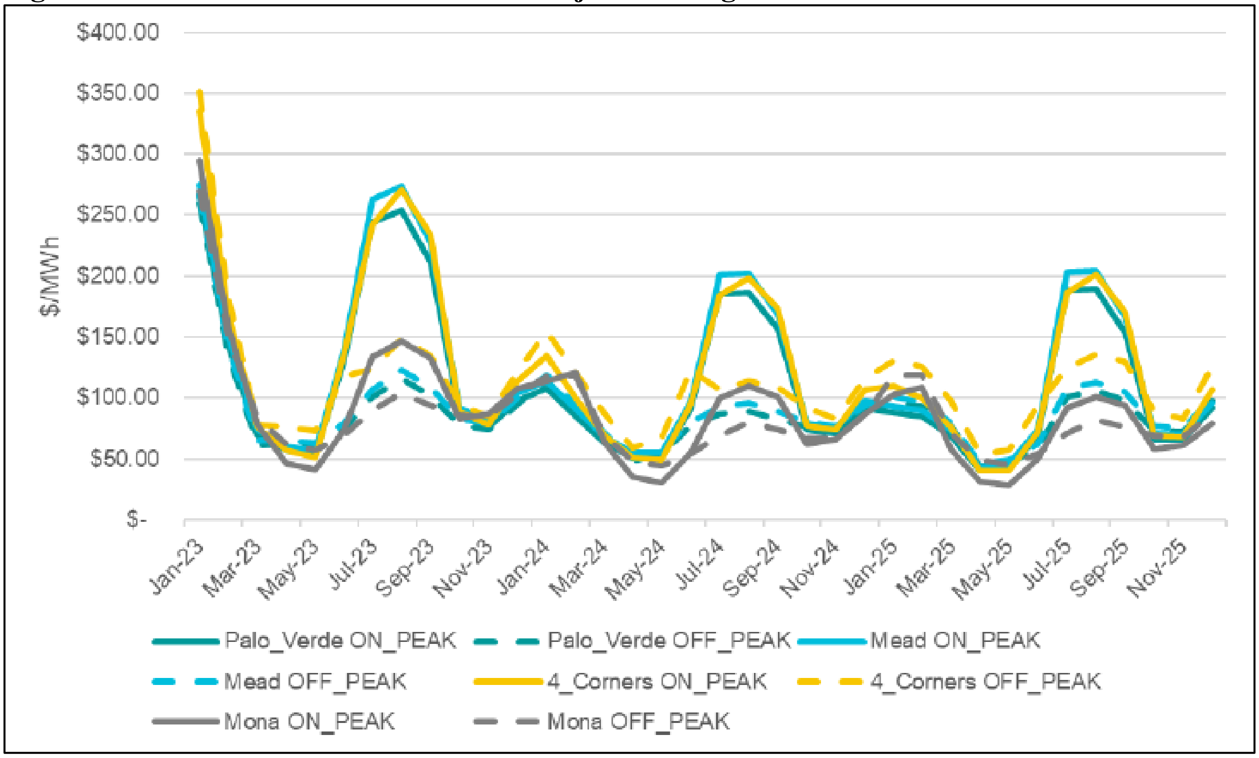
Month	2021	2022	Difference	Percent
Jan	$ 28.30	$ 45.24	$ 16.94	60%
Feb	$ 60.88	$ 42.59	$ (18.29)	-30%
Mar	$ 28.88	$ 37.32	$ 8.44	29%
Apr	$ 34.14	$ 66.16	$ 32.02	94%
May	$ 32.00	$ 61.20	$ 29.20	91%
Jun	$ 82.49	$ 57.27	$ (25.21)	-31%
Jul	$ 105.63	$ 81.46	$ (24.18)	-23%
Aug	$ 71.58	$ 117.22	$ 45.64	64%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

Source: SNL

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

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

Figure 3.1 - Forward Prices at WECC Major Trading Hubs



Source: OTC, Siemens PTI

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

Table 3.2 - 2023-2025 Forward Price Spread

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

Source: OTC

Power Market Dynamics

Non-CAISO WECC Generation and Capacity Mix

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

Figure 3.2 - National RPS Targets

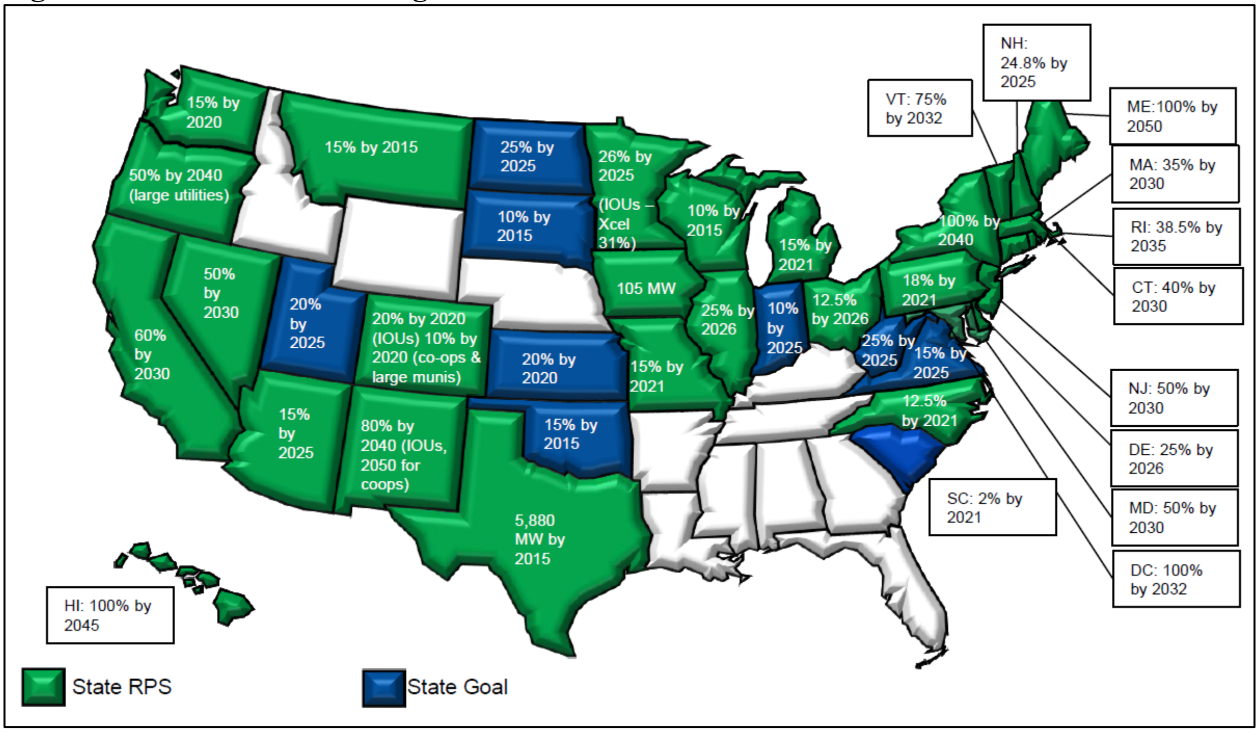
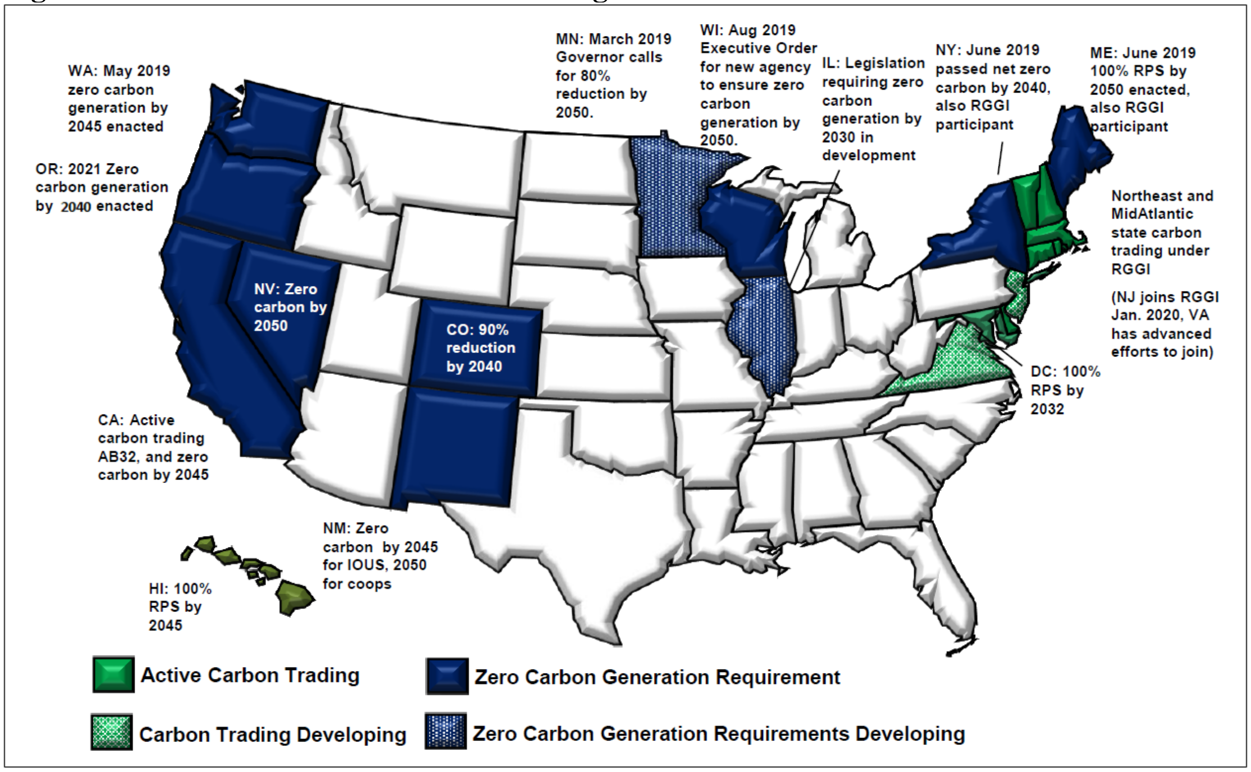
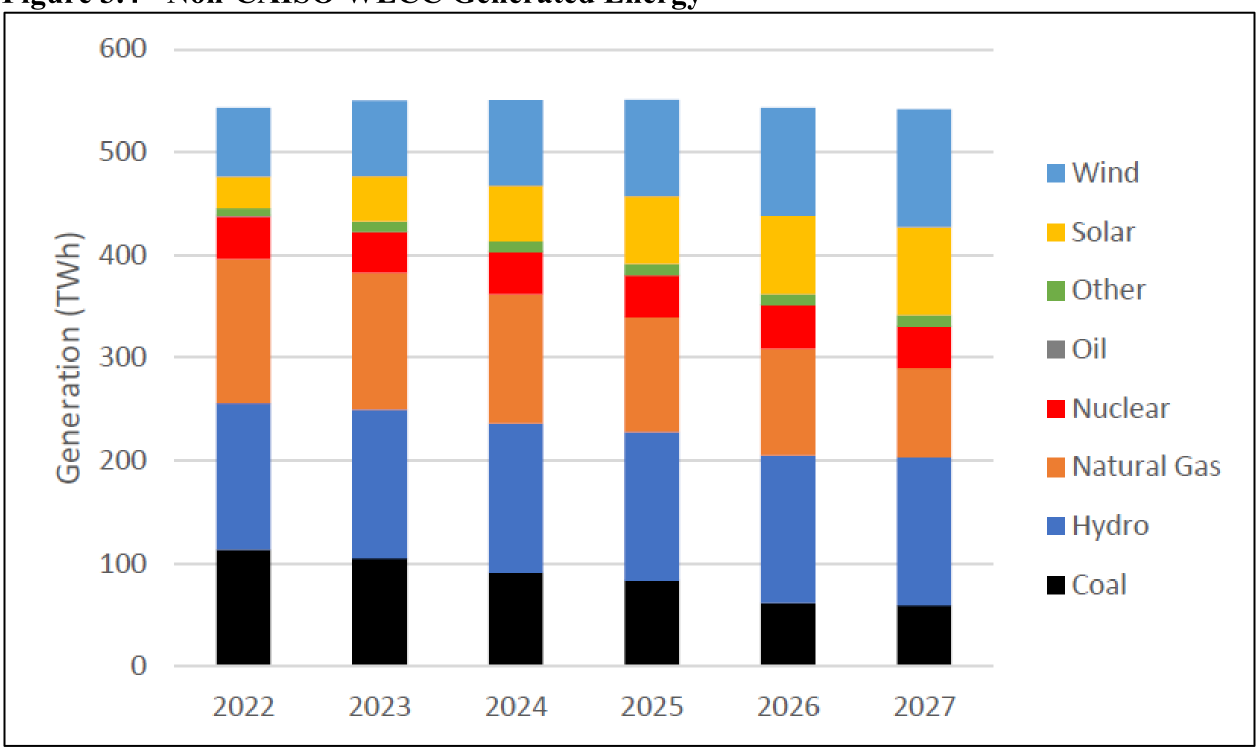


Figure 3.3 - States with CO_2 Reduction Targets



Source: Siemens PTI

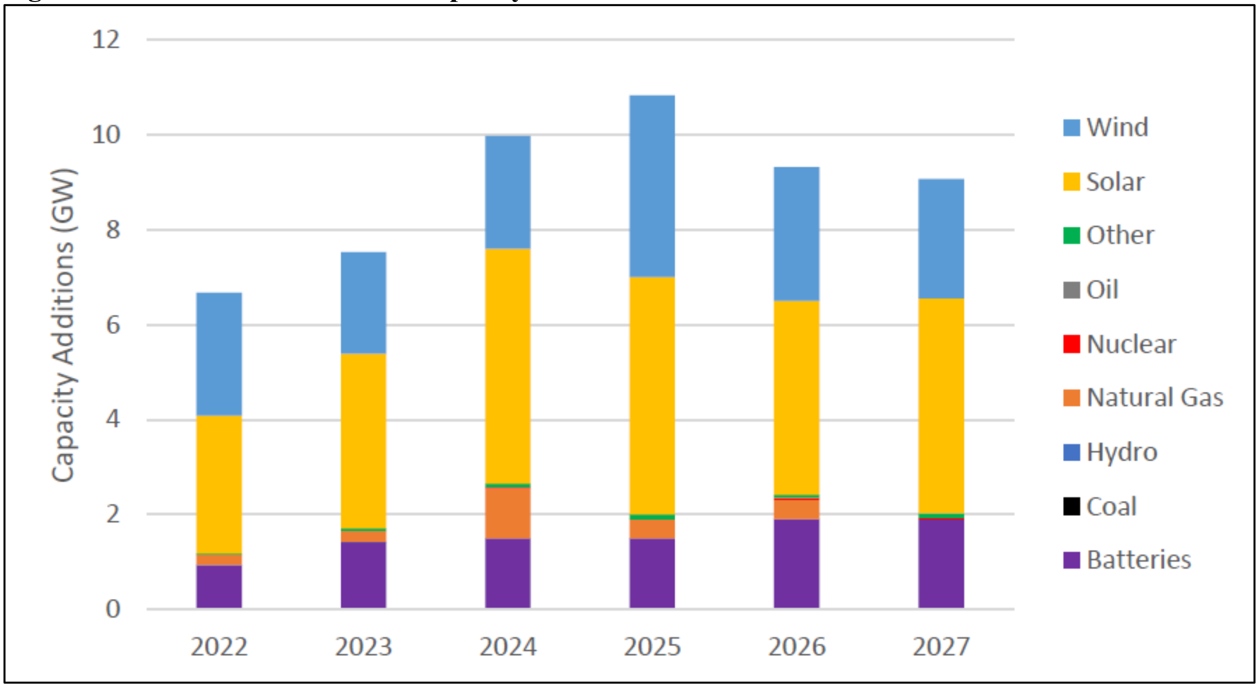
Figure 3.4 - Non-CAISO WECC Generated Energy



Source: IHS Markit, SNL, Siemens PTI

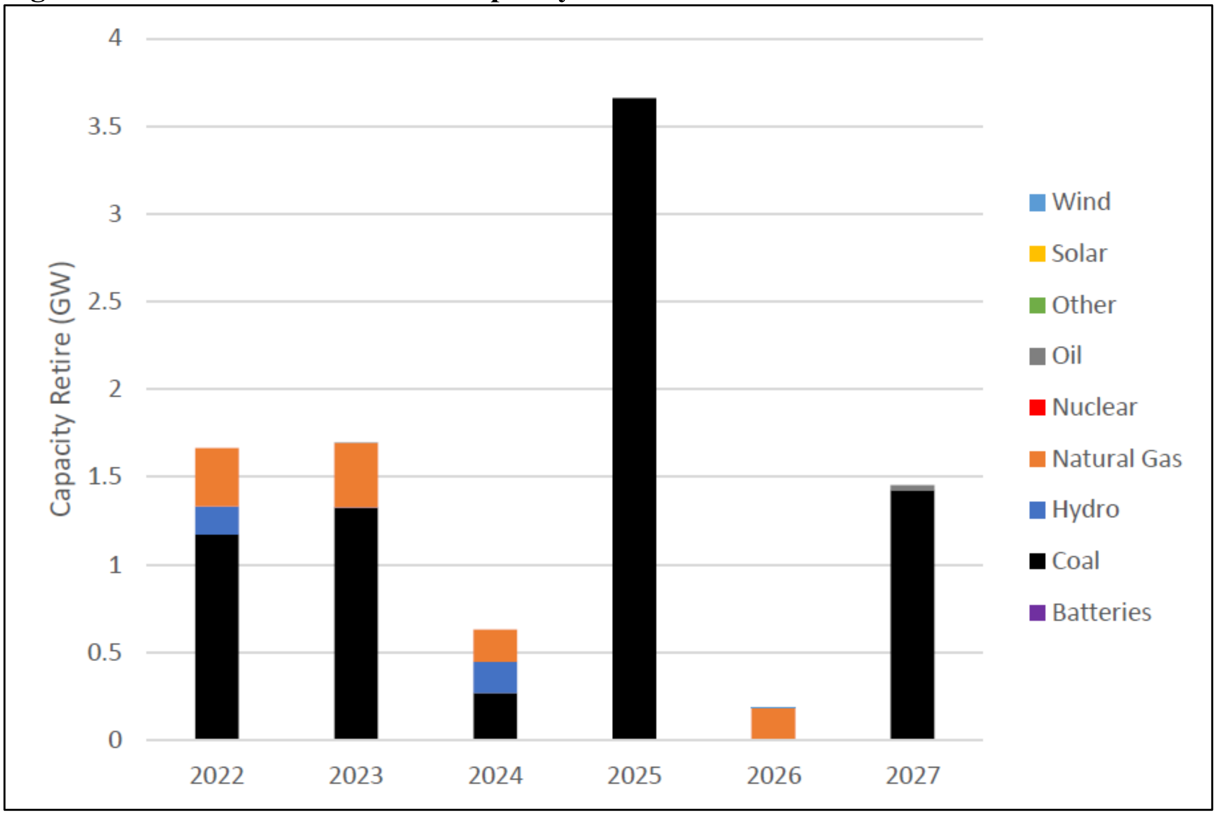
2022 saw the addition of almost 2.5 GW of wind resources and 2.9 GW of Solar. Into 2023 Siemens expects approximately 3.6 GW of wind 2.1 GW of solar to come online as according to interconnection queues. Just under 1 GW of storage capacity came online in 2022 and some 1.4 GWs of storage are expected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

Figure 3.5 - Non-CAISO WECC Capacity Addition



Source: IHS Markit, SNL, Siemens PTI

Figure 3.6 - Non-CAISO WECC Capacity Retirement



Source: IHS Markit, SNL, Siemens PTI

Emissions and Environment

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

Non-CAISO WECC Demand Forecast

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

Forward Influence of the IRA

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

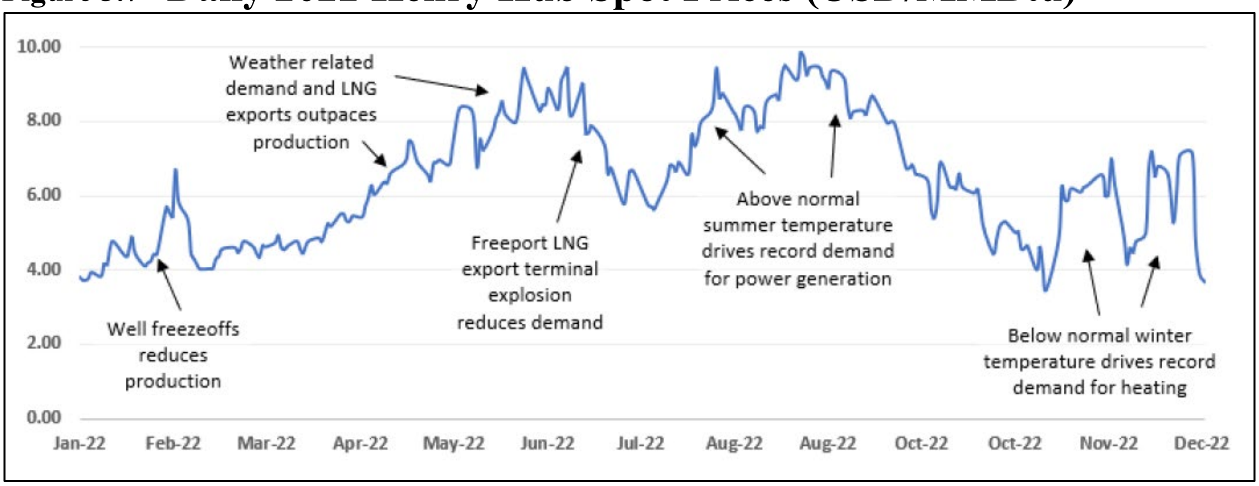
Natural Gas Prices

2022 Summary

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

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

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



Source: S&P Global, Siemens PTI

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

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

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

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

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

2023 Forward View

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

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

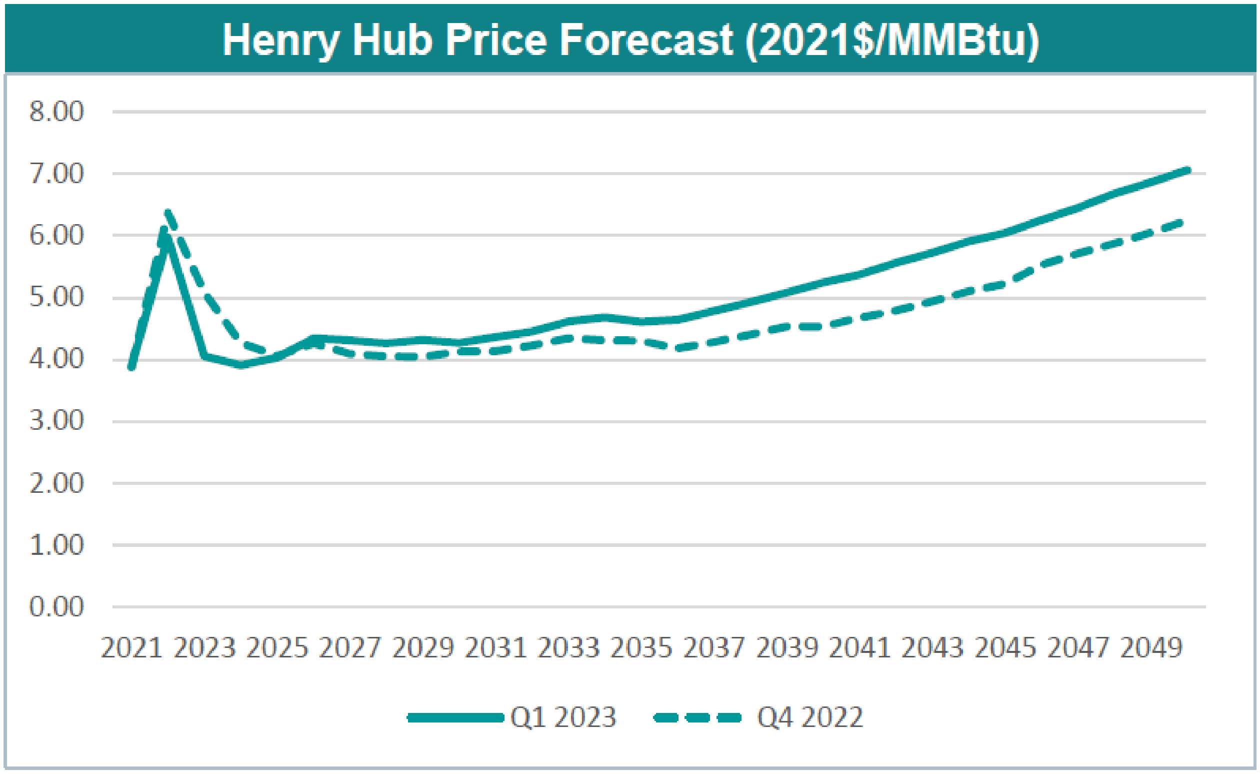
2024-2030 Forward View

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

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

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

Figure 3.8 – Henry Hub Futures



Conclusion

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

PacifiCorp's Multi-State Process

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

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

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

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

List of Implemented Issues

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

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

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

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

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

List of Resolved Issues

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

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

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

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

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

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

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

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

Update on 2020 Protocol and Status of Framework Issues

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

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

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

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

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

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

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

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

Analysis of "Outstanding Material Disagreements"

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

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

Environmental Regulation

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

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

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

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

Federal Policy Update

National Electric Vehicle Infrastructure Formula Program

$5 Billion FY 2022-2026
The U.S. Department of Transportation's (DOT) Federal Highway Administration (FHWA) NEVI Formula Program will provide funding to states to strategically deploy electric vehicle (EV) charging stations and to establish an interconnected network to facilitate data collection, access, and reliability. Funding is available for up to 80% of eligible project costs, including:

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

Section 11401 Grants for Charging and Fueling Infrastructure

- $2.5 billion for FY 2022 – 2026.

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

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

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

Features of the IRA include:

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

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

New Credits and Considerations for Customer Resources–Inflation Reduction Act

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

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

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

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

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

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

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

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

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

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

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

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

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

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

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

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

Ozone NAAQS

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

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

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

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

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

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

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

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

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

Particulate Matter NAAQS

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

Regional Haze

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

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

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

Utah Regional Haze

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

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

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

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

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

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

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

Wyoming Regional Haze

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

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

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

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

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

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

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

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

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

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

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

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

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

Mercury and Hazardous Air Pollutants

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

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

Coal Combustion Residuals

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

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

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

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

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

Water Quality Standards

Cooling Water Intake Structures

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

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

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

Effluent Limit Guidelines

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

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

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

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

Renewable Generation Regulatory Framework

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

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

Tax Extender Legislation

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

State Policy Update

California

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

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

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

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

Oregon

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

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

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

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

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

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

Washington

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

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

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

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

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

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

- Improving the efficiency of their fuel production processes

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

Utah

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

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

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

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

Wyoming

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

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

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

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

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

Greenhouse Gas Emission Performance Standards

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

Renewable Portfolio Standards

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

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

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

Table 3.3 – State RPS Requirements

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

California

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

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

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

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

Table 3.4 – California Compliance Period Requirements

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

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

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

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

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

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

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

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

Table 3.5 – California Balanced Portfolio Requirements

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

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

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

Oregon

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

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

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

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

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

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

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

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

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

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

Utah

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

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

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

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

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

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

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

Washington

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

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

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

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

REC Management Practices

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

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

Clean Energy Standards

Washington

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

Oregon

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

California

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

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

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

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

Wyoming

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

Transportation Electrification

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

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

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

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

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

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

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

Hydroelectric Relicensing

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

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

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

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

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

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

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

Potential Impact

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

Treatment in the IRP

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

PacifiCorp's Approach to Hydroelectric Relicensing

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

Rate Design

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

Residential Rate Design

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

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

Commercial and Industrial Rate Design

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

Irrigation Rate Design

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

Electricity Market Development Update

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

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

Figure 3.9 – Western Energy Imbalance Market Expansion

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

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

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

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

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

Recent Resource Procurement Activities

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

Table 3.6 – PacifiCorp's Requests for Proposal Activity

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

2020 All-Source RFP

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

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

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

2021 DR RFP

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

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

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

2022 All-Source RFP

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

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

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

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

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

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

Introduction

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

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

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

This chapter provides:

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

Regulatory Requirements

Open Access Transmission Tariff

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

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

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

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

Reliability Standards

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

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

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

Generation Interconnection Cluster Study Process

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

Generation Interconnection Study Methodology Changes

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

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

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

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

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

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

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

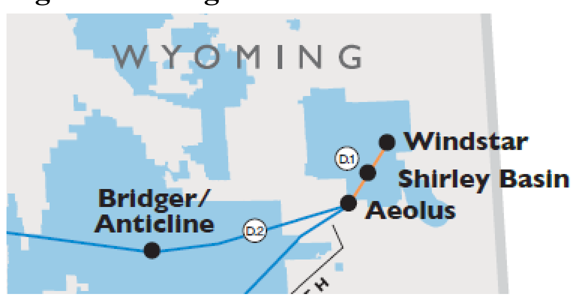
Windstar-Populus (Gateway West – Segment D)

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

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

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

Figure 4.1 - Segment D



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

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

Populus-Hemingway (Gateway West - Segment E)

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

Figure 4.2 - Segment E

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

Plan to Continue Permitting – Gateway West

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

Boardman-Hemingway (Segment H)

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

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

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

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

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

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

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

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

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

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

Anticline-Shirley Basin Transmission Line

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

Other Transmission System Improvements

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

Energy Gateway Transmission Expansion Plan

Introduction

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

Background

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

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

Planning Initiatives

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

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

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

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

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

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

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

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

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

Energy Gateway Configuration

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

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

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

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

Energy Gateway's Continued Evolution

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Figure 4.3 – Energy Gateway Transmission Expansion Plan

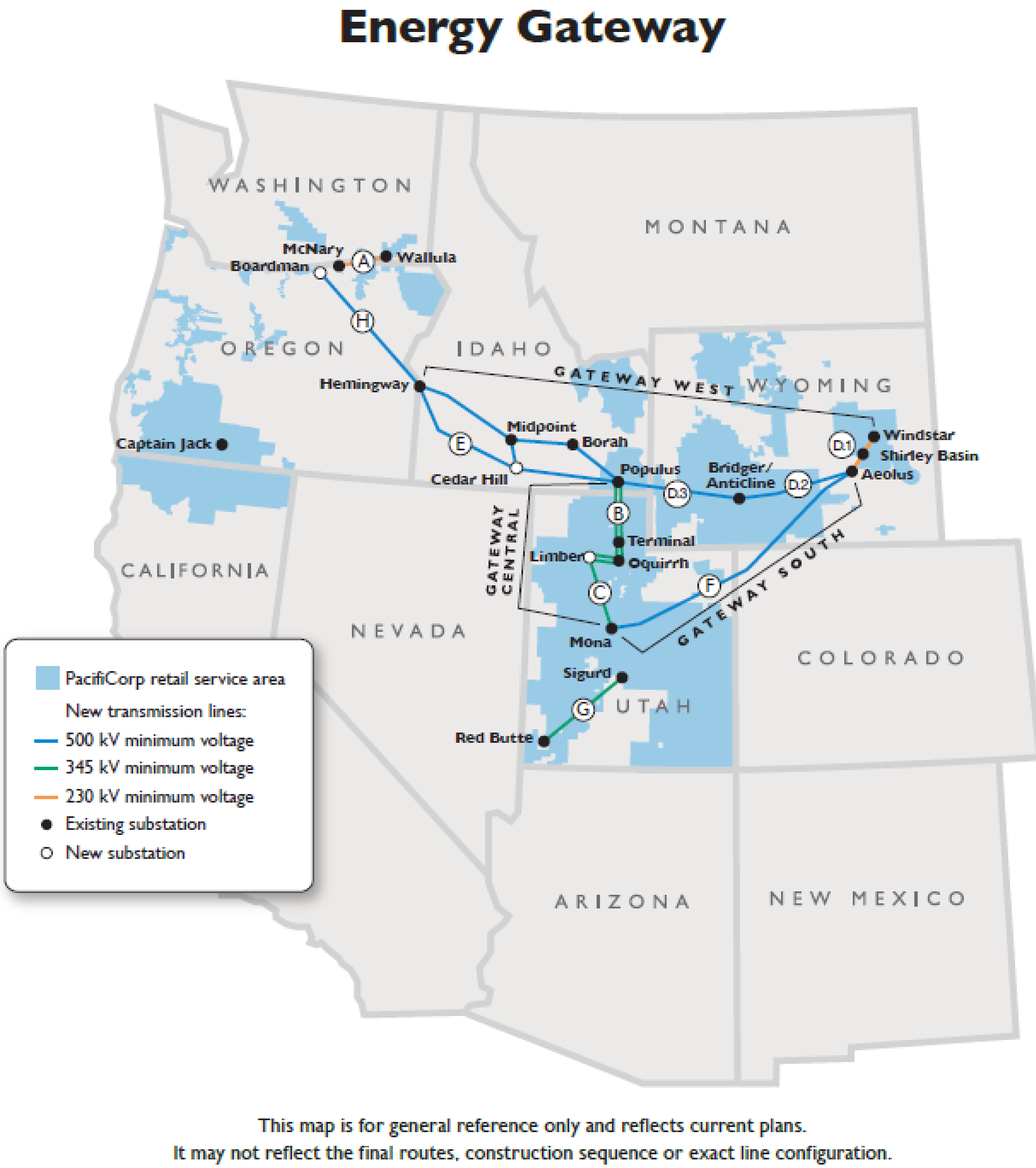


Table 4.1 – Energy Gateway Transmission Expansion Plan

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

Efforts to Maximize Existing System Capability

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

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

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

Transmission System Improvements Placed In-Service Since the 2021 IRP

PacifiCorp East (PACE) Control Area

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

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

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

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

4. Utah, Idaho & Wyoming - Upgrade Program – Replace Over-dutied Circuit Breakers

- Replaced breakers identified as over-dutied with higher-capability breakers in various substations located in Idaho, Utah, and Wyoming
  - Project driver was to correct NERC Standard TPL-001-4 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of 13 over-dutied breakers.
  - Benefits include eliminating the risk of over-dutied breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-4 Requirement R2.3 deficiencies.

5. Goshen Idaho Area

- Rebuilt and converted an existing 69-kV line to 161-kV to establish a new 161-kV source at Rexburg substation in Idaho
  - Project driver was to improve 69-kV capacity and voltage regulation served from Rigby substation by converting an existing 69-kV line to 161 kV to create a 161-kV source at Rexburg substation through a new 161-69 kV transformer installation. The project also will include a new six breaker 69-kV ring bus at Rexburg substation that includes terminating two existing 69-kV lines and one new 69-kV line.
  - Benefits include establishing a new 161-kV source in the area, providing additional 69-kV capacity, improving 69-kV voltage regulation and reliability to customers served from the 69-kV system.

6. Park City Utah Area

- Installed a 9-mile, 138-kV transmission line between Midway and Jordanelle substations in Utah
  - Project drivers were projected load growth and reliability improvements which required of extension of the 138-kV line from Jordanelle-to-Midway substation.
  - Benefits are the established new 138-kV loop, additional capacity to address projected load growth and improved transmission reliability.

PacifiCorp West (PACW) Control Area

1. Albany/Corvallis Oregon Area

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

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

2. Medford Oregon Area

- Expanded the RAS at Meridian substation
  - Project driver was to expand the existing RAS to cover three additional N-1-1 contingencies on the southern Oregon 500-kV system and trip additional load as identified in the 2015 Meridian Area Load Tripping Assessment and the 2017 NERC TPL Assessment.
  - Benefit of expanding the RAS will be to avoid relying on the Southern Oregon Under-Voltage Load Shedding scheme as the primary mitigation for double contingencies on the 500-kV system.

3. Yakima Washington Area

- Constructed a new 115-kV transmission line from Outlook substation to Punkin Center substation
  - Project driver was to correct NERC Standard TPL-001-4 Category P1 deficiencies identified in the 2016 NERC TPL Assessment for single contingency (N-1) outages on the 230-kV system serving the Yakima Upper Valley.
  - Benefits include mitigating the risk of thermal overloads, resolving an existing capacity limitation on the 115-kV line, improving transfer capability between the Upper Valley and the Lower Valley system, and resolution of the NERC TPL-001-4 Category P1 deficiency.

4. Oregon – Upgrade Program – Replace Over-dutied Circuit Breakers

- Replaced breakers identified as over-dutied with higher-capability breakers at Lone Pine Substation
  - Project driver was to correct NERC Standard TPL-001-4 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of three over-dutied 115-kV breakers.
  - Benefits include eliminating the risk of over-dutied 115-kV breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-4 Requirement R2.3 deficiencies.

Planned Transmission System Improvements

PacifiCorp East (PACE) Control Area

1. Central Utah Area

- Upgrade the 345-138 kV 167 MVA transformer at Camp Williams substation to a 345-138 kV 700 MVA transformer

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

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

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

PacifiCorp West (PACW) Control Area

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

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

4. Klamath Falls Oregon Area
   - Construct a second 230 kV transmission line from Snow Goose to Klamath Falls substation.
     - Project driver is to resolve NERC Standard TPL-001-4 Category P6 (N-1-1) for a double contingencies on the 230 kV system serving Yreka, Klamath Falls and La Pine area for the loss of the Klamath Falls-Snow Goose 230 kV line and either the Lone Pine-Copco 230 kV line or Bonneville Power Administration's (BPA) Pilot Butte-La Pine 230 kV line can cause a voltage collapse affecting a large region of the southern Oregon and northern California system.
     - Benefits include Reinforces 230 kV system between in Klamath Falls area to cover TPL-001-4 category P6 (N-1-1) contingencies during all operating conditions on the existing system and minimize risk of a large-scale outage to customers throughout the Klamath Falls and Yreka areas.
5. Medford Oregon Area
   - Construct a 230 kV transmission line between Lone Pine and Whetstone substations
     - Project driver is to correct NERC Standard TPL-001-4 Category P1 (N-1) and P6 (N-1-1) outage combinations including loss of the two Meridian-Lone Pine 230 kV lines (N-1), N-1-1 loss of the Meridian-Whetstone and Dixonville-Grants Pass 230 kV lines, or N-1-1 loss of Sams Valley 500-230 kV source and either the Meridian-Whetstone 230 kV line or Dixonville-Grants Pass 230 kV line.
     - Benefits include resolving the NERC Standard TPL-001-4 Category P1 and P6 issues as well as prevents reverse flow across the Medford 115 kV system to support the 230 kV system and allows operating the Medford 115 kV system radial.
   - Construct one new 500-230 kV substation called Sams Valley
     - Project driver is to correct NERC Standard TPL-002-4 deficiencies for the loss of a single 230-kV line and for N-1-1 and N-2 outages to 230-kV lines that were initially identified in PacifiCorp's 2010 NERC TPL Assessment and supported through subsequent NERC TPL Assessments, and to provide a second 500-kV source to address load growth in the Southern Oregon region.
     - Benefits include adding a second source of 500-kV capacity, adding a new 230-kV line, improving reliability of the 230-kV network, mitigates the risk of thermal overloads and low voltage, mitigates the risk of shedding load in preparation of the second contingency for N-1-1 outages, and resolves the NERC TPL-001-4 deficiencies.

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

CHAPTER 5 – RELIABILITY AND RESILIENCY

CHAPTER HIGHLIGHTS

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

Introduction

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

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

Supply-Based Reliability

Regional Resource Adequacy

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

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

WECC Western Assessment of Resource Adequacy Report

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

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

Table 5.1 – Planning Subregions and Peaking Assumptions underlying analysis

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

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

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

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

WPP-NW

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

NWPP-NE

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

Resource Assumptions

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

> **Recommendation 1:** *Resource plans should include contingency plans to manage the risk of impediments to building planned resources. State commissions and regulatory bodies should continue to scrutinize integrated resource plans to ensure that utilities are planning for the increased risks. Likewise, commissions must be prepared to consider recovery of costs incurred by the utilities as they plan for increased risks.*

  - PacifiCorp's transmission system provides access to diverse resource opportunities, which limits its reliance on particular locations, and allows it to flexibly respond to evolving opportunities.

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

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

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

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

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

NERC Long-Term Reliability Assessment (LTRA)

Resources

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

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

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

Tier 2: Prospective Resources

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

Tier 3:

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

Planning Reserve Margin

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

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

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

WECC Subregions

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

Table 5.2 – WECC Subregion Descriptions

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

LTRA WECC Assessment

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

Table 5.3 – NERC LTRA Anticipated Reserve Margin

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

Table 5.4 – NERC LTRA Prospective Reserve Margin

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

Table 5.5 – NERC LTRA Reference Reserve Margin

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

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

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

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

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

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

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

Prior Measures

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

Pacific Northwest Resource Adequacy Forum's Adequacy Assessment

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

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

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

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

2021 Northwest Power Plan

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

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

NWPP Resource Adequacy Program

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

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

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

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

Reliable Service through Unpredictable Weather and Challenging Market Liquidity

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

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

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

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

Table 5.8 – Maximum Available Front Office Transactions by Market Hub

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

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

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

Planning for Load Changes as a Result of Climate Change

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Weather-Related Impacts to Variable Generation

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

Wildfire Impacts

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

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

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

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

PacifiCorp outlines its wildfire mitigation strategies later in this document.

Extreme Weather Impacts

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

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

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

Impacts on wind and solar energy

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

Wind Energy

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

[10] Climate change impacts on the energy system: a review of trends and gaps. Cronin, J., Anandarajah, G. & Dessens, O. Climatic Change volume 151, August 2018.

[11] Climate change impacts on renewable energy generation. A review of quantitative projections. Kepa Solaun, Emilio Cerdá. Renewable and Sustainable Energy Reviews

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

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

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

Wildfire Risk Mitigation

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

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

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

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

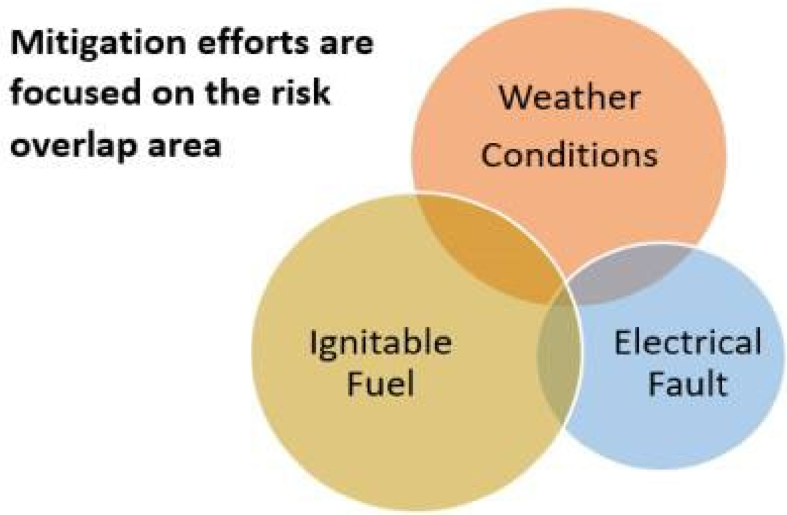
The company continues to build on over a century of wildfire mitigation experience and three decades of information gathering and analysis. PacifiCorp's planning focus areas above are intended to ensure that we continue to serve customers safely and reliably. As new analyses, technologies, practices,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

Risk Analysis and Drivers

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

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

Figure 5.1 – Wildfire Risk Mitigation Focus Areas



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

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

Situational Awareness

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

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

Weather Stations

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

Meteorology

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

Inspection and Correction

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

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

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

Vegetation Management

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

System Hardening

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

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

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

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

Line Rebuild Program

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

Covered Conductor

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

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

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

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

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

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

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

Non-Wooden Poles

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

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

Non-Expulsion Fuses

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

Advanced System Protection and Control

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

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

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

Operational Practices

System Operations

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

Elevated Fire Risk Settings

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

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

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

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

Re-energization Practices

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

Field Operations

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

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

Work Restrictions

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

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

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

Additional Labor Resources

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

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

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

Equipment and Tool Purchases

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

Vehicles

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

Basic Personal Suppression Equipment

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

Water Truck Resources

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

Transmission-Based Reliability

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

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

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

Federal Reliability Standards

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

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

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

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

Power Flow Analyses and Planning for Generator Retirements

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

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

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

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

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

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

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

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

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

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

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

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

CHAPTER 6 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

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

Introduction

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

System Coincident Peak Load Forecast

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

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

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

Existing Resources

Thermal Plants

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

Table 6.2 – Coal Fired Plants

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

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

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

Table 6.3 – Natural Gas Plants

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

Renewable Resources

Wind

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

Table 6.4 – Owned Wind Resources

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

*New projects added in 23 IRP

Table 6.5 – Non-Owned Wind Resources

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

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

*New projects added in 23 IRP

Solar

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

Table 6.6 – Solar Resources

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

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

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

* New projected added in 2023 IRP

Geothermal

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

Biomass/Biogas

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

Storage

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

Table 6.7 – Storage Resources

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

*New projects added in 2023 IRP

Renewables Private Generation

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

Table 6.8 – Private Generation Customers and Capacity

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

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

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

Hydroelectric Generation

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

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

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

Table 6.9 – PacifiCorp Hydroelectric Generation Facilities

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

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

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

Demand-Side Management/Distributed Generation

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

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

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

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

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

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

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

Table 6.10 – Existing DSM Resource Summary

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

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

Private Generation Forecast

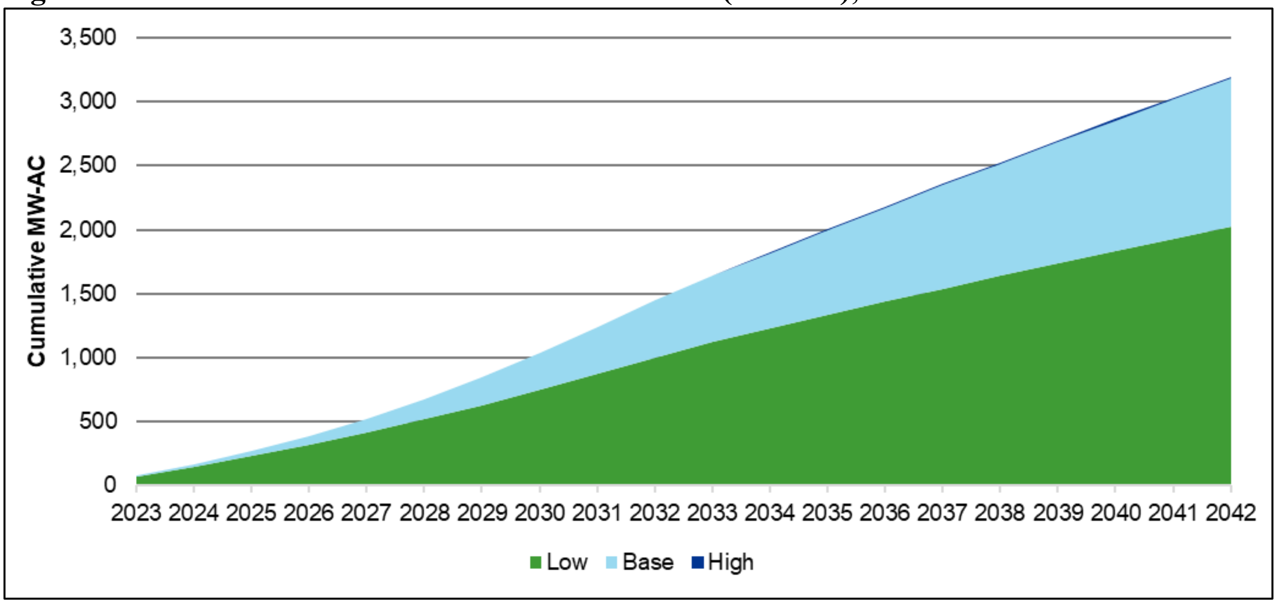
For the 2023 IRP, PacifiCorp contracted with DNV to update the assessment of private generation (PG) penetration performed for the 2023 IRP with new market, policy, and incentive developments. The study provided a forecast of adoption of behind-the-meter (BTM) customer generation resources in each of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

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

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

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

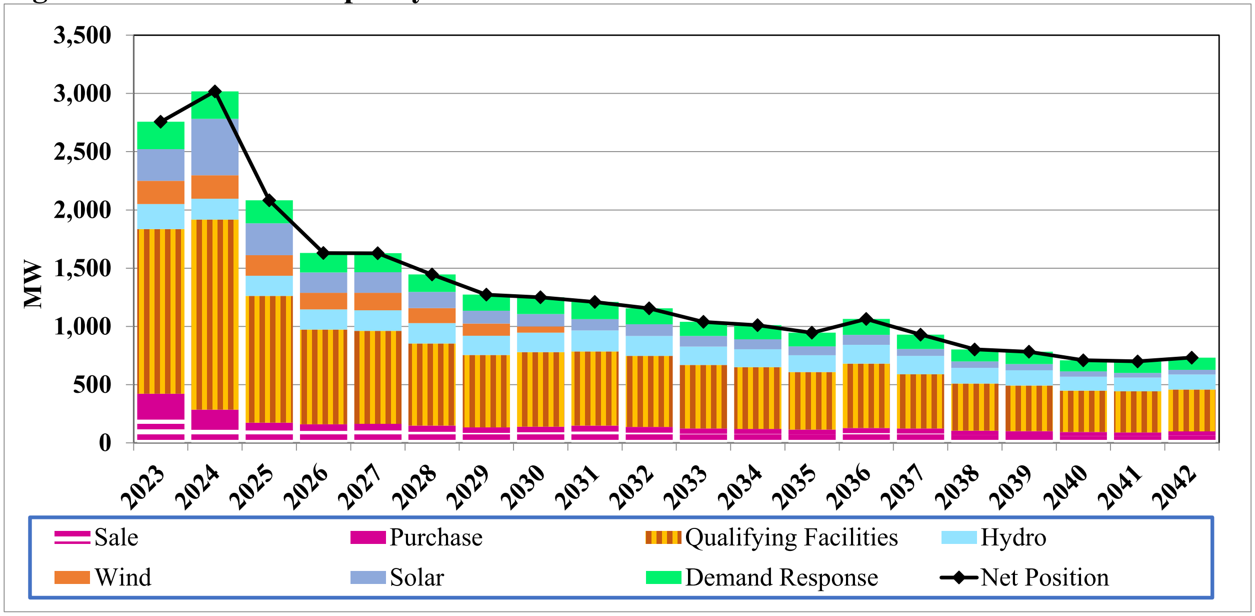
Figure 6.1 – Private Generation Market Penetration (MWAC), 2023-2042



Power-Purchase Agreements

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

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



Capacity Load and Resource Balance

Capacity Balance Overview

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

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

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

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

Load and Resource Balance Components

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

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

Existing Resources
A description of the resource categories follows:

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

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

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

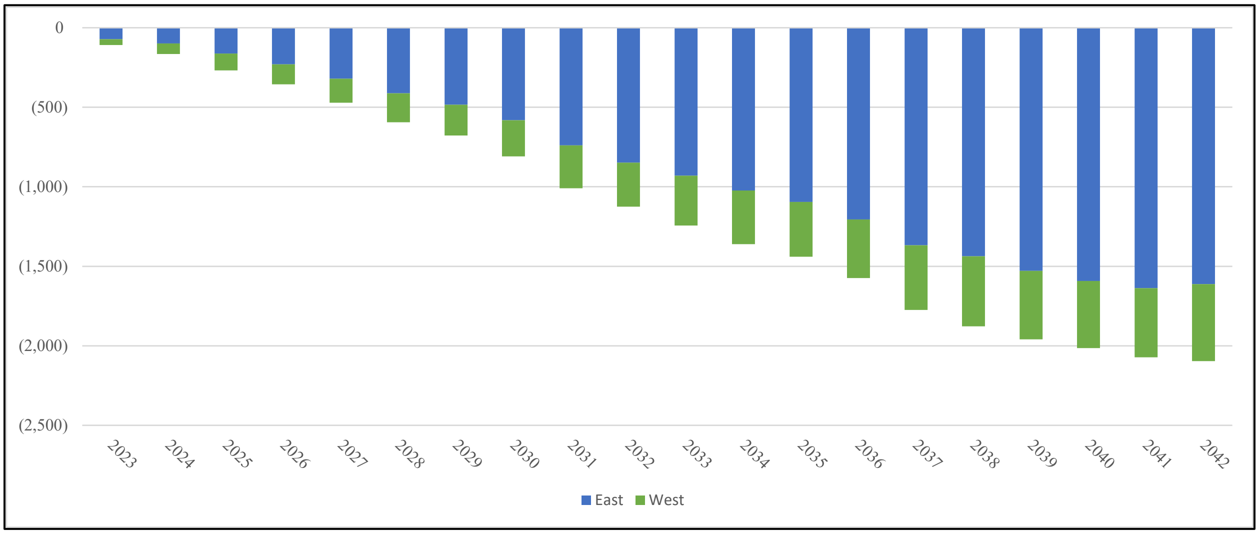
Sales
Contracts for the sale of firm capacity and energy are treated the same as all other resources, except that they have a negative capacity value.

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

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

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

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



Demand Response

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

Planning Reserve Margin

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

Position

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

Capacity Balance Determination

Methodology

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

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

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

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

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

> **Planning Reserves** = Obligation x PRM

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

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

Capacity Balance Results

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

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

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

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

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

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

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

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

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

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

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

Figure 6.4 – Summer System Capacity Position Trend

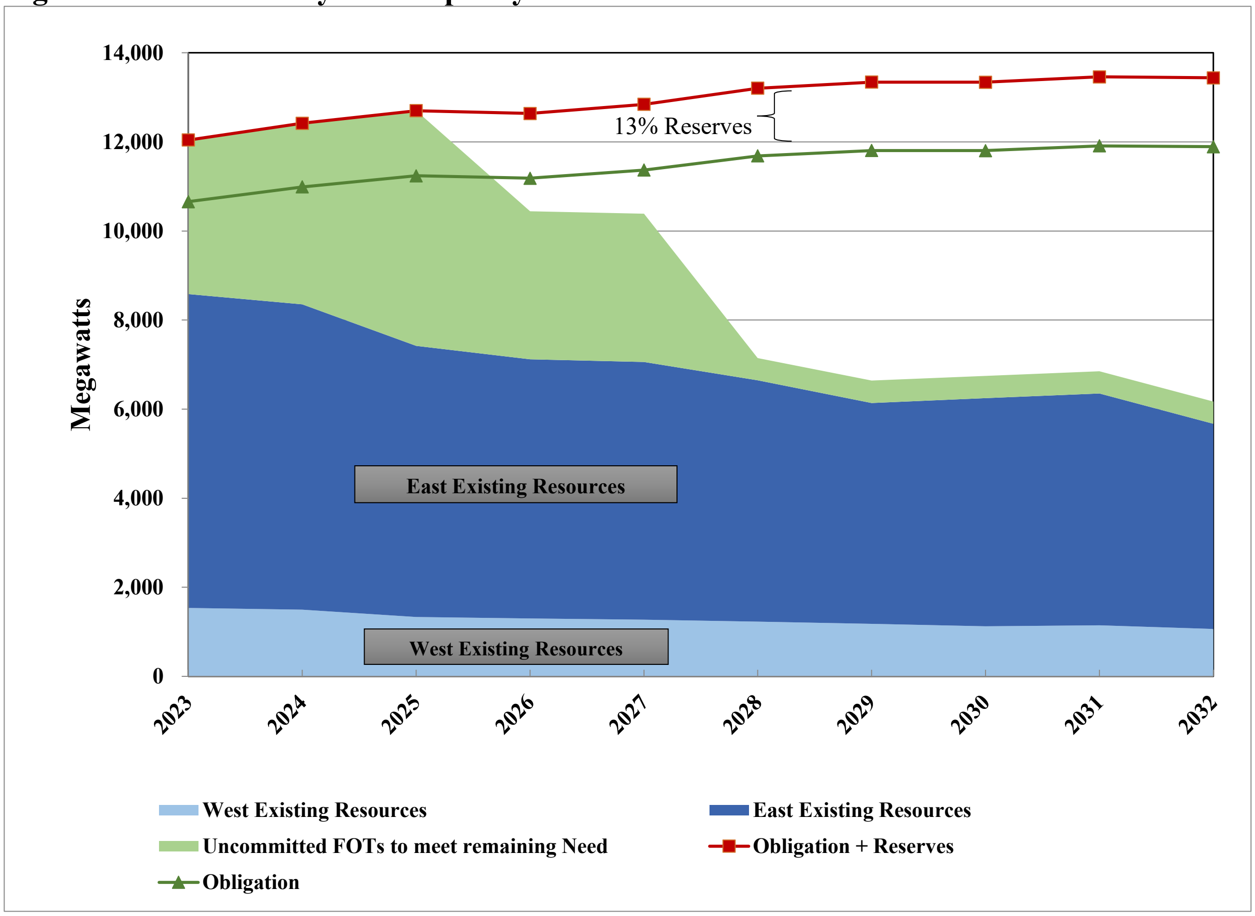


Figure 6.5 – Winter System Capacity Position Trend

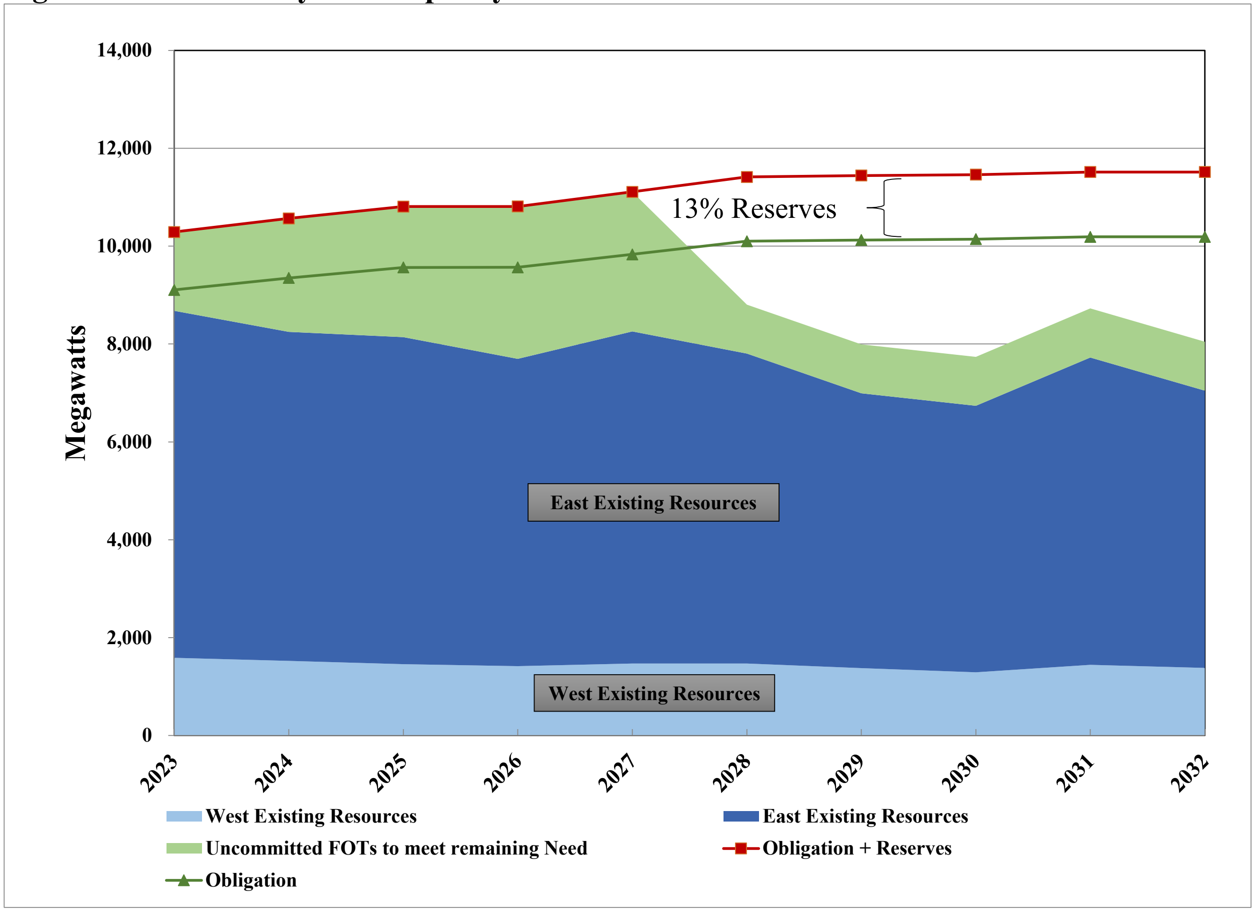


Figure 6.6 – East Summer Capacity Position Trend

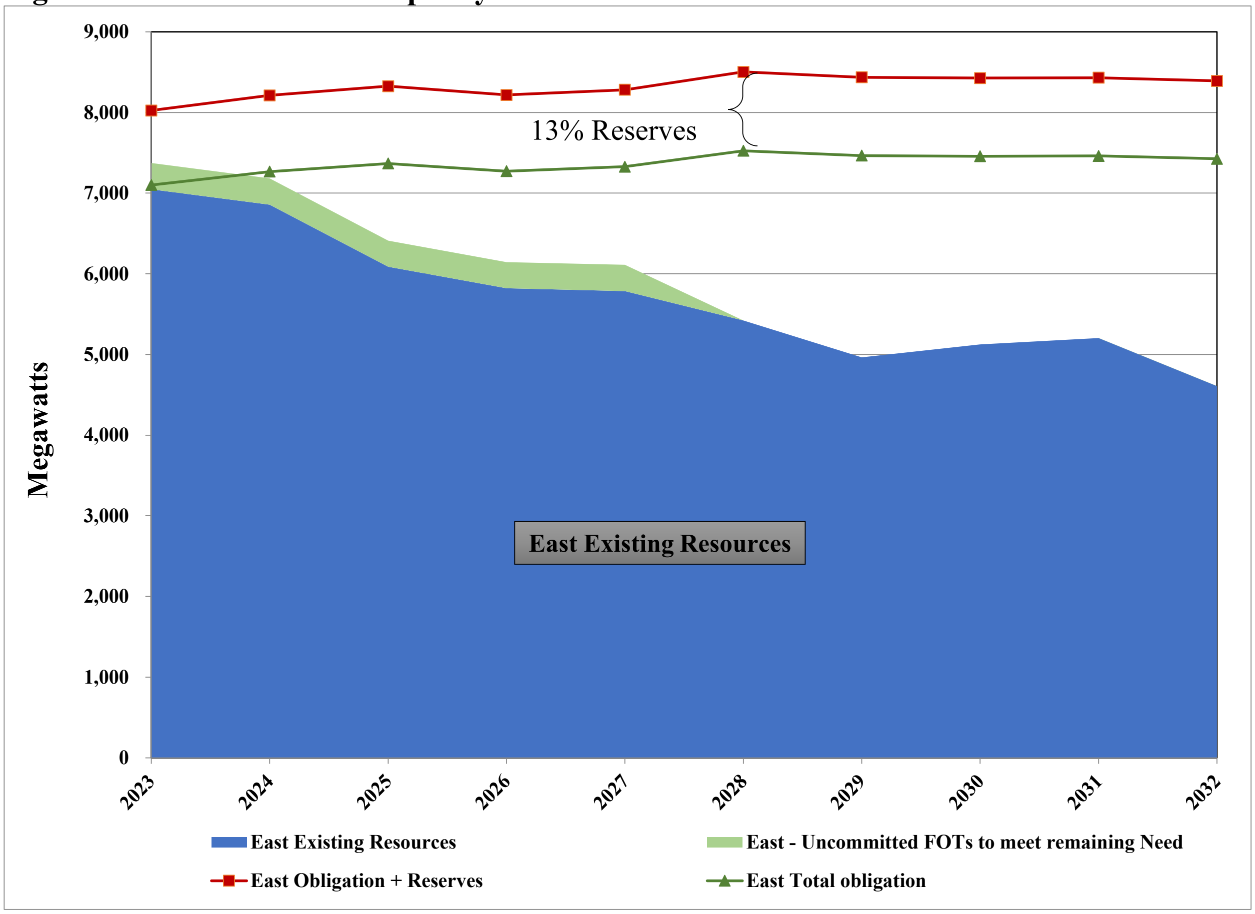
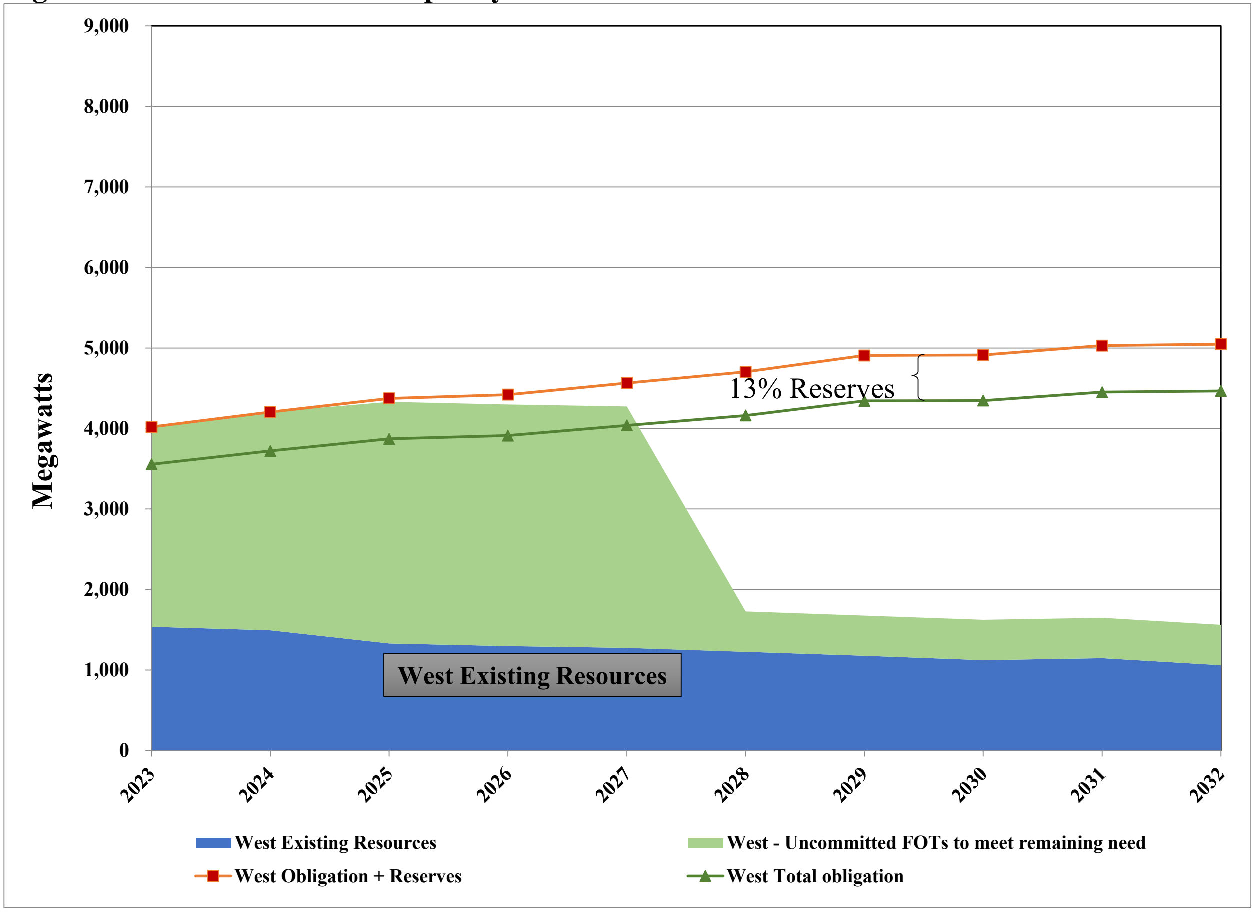


Figure 6.7 – West Summer Capacity Position Trend



CHAPTER 7 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

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

Introduction

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

Supply-Side Resources

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

Derivation of Resource Attributes

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

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

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

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

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

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

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

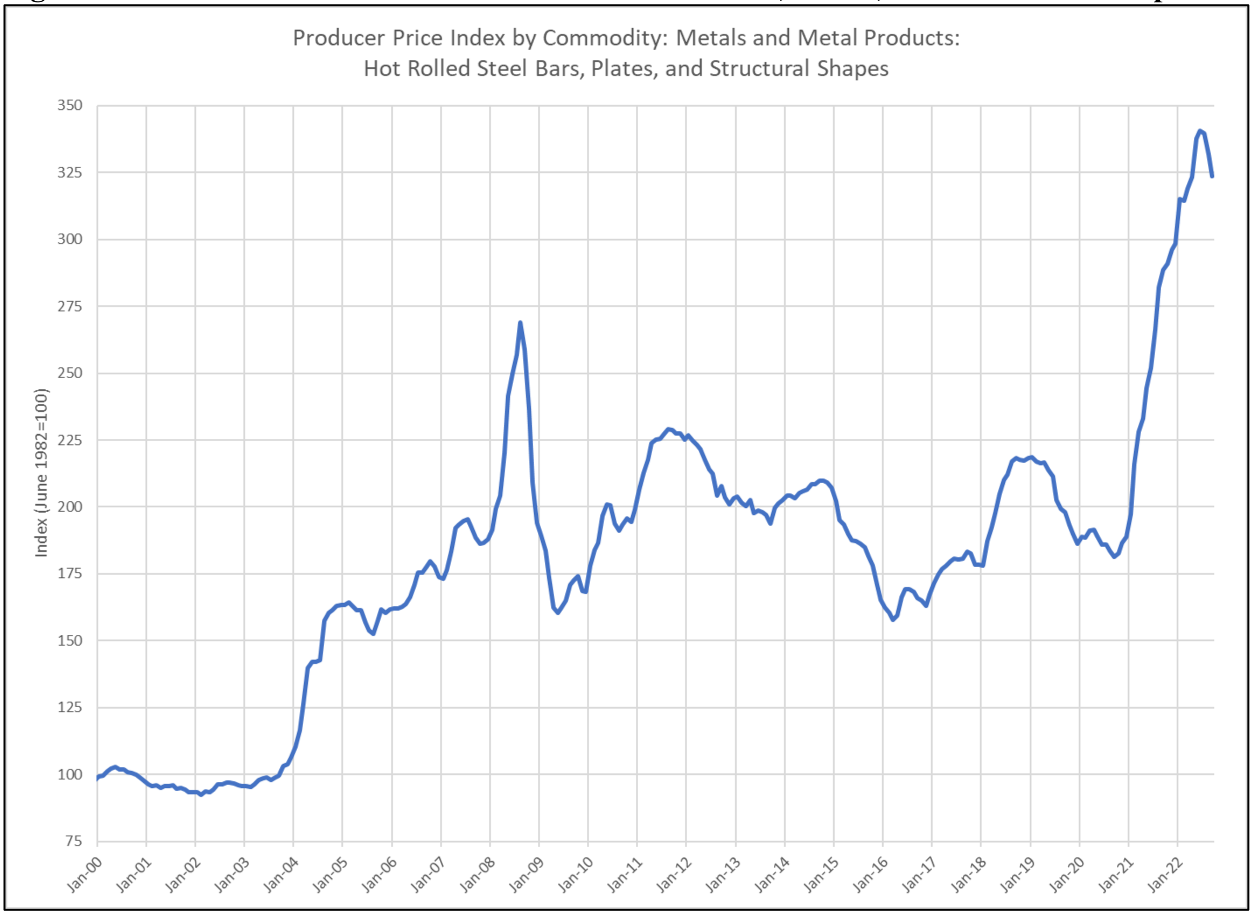
To achieve this, the objective of the ESR study was to provide high-level analyses of how the 1.0 GW of OSW displaces other resources that are integral to the WECC 2032 Anchor Data Set ("ADS") and are serving PacifiCorp network Loads, consistent with Loads and Resources in PacifiCorp 2021 IRP. A conceptual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

Handling of Technology Improvement Trends and Cost Uncertainties

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

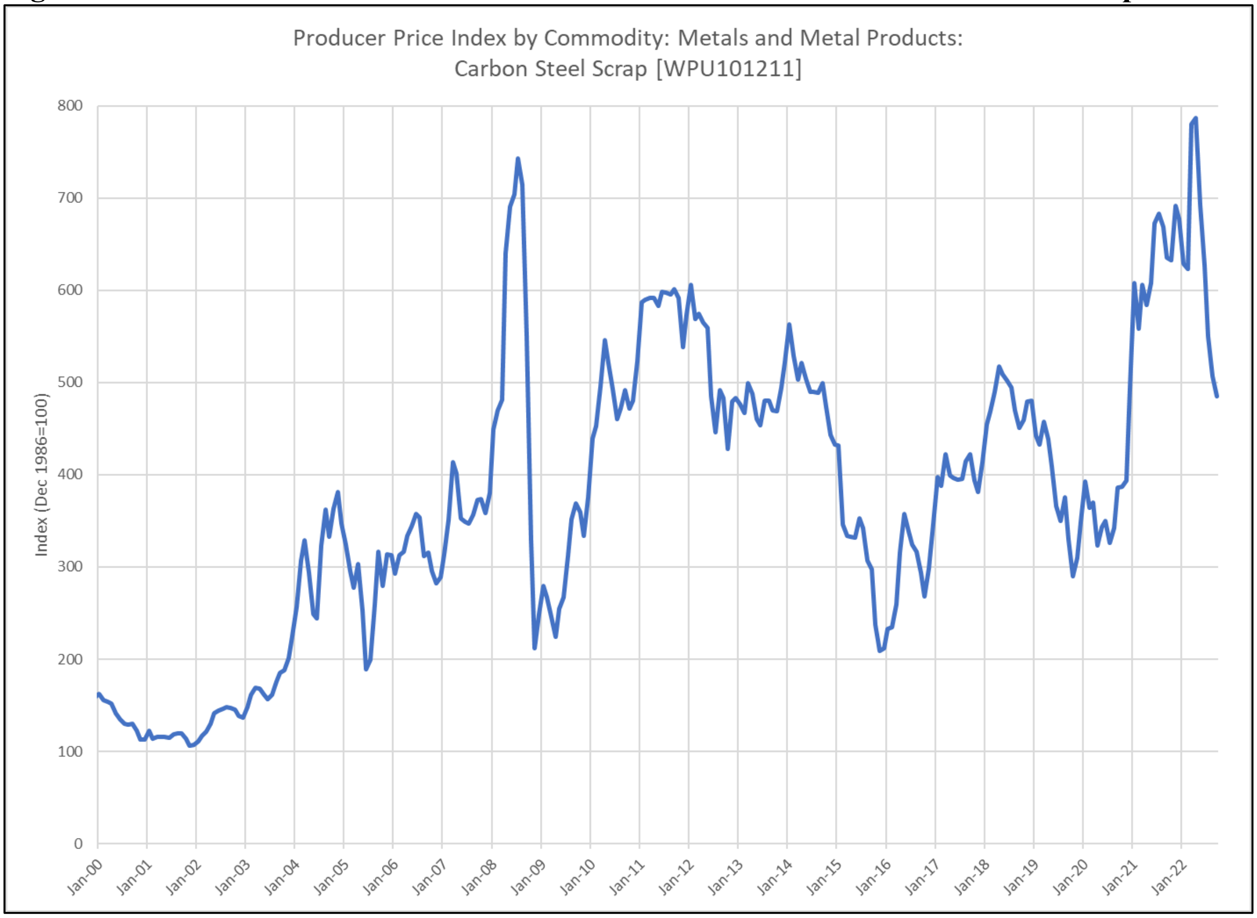
2 https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Adding_OffShore_Wind_at_DelNorte_Draft_ESR_Report.pdf

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



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

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



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

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

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

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

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

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

Resource Options and Attributes

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Supply Side Resource Options Mid-Calendar Year 2022 Dollars ($)					Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
Adiabatic CAES, RESC, 500 MW, 12000 MWh	6500'	80%	$34.62	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$35.73	$ -	$35.73
Adiabatic CAES, RESC, 500 MW, 24000 MWh	6500'	80%	$46.98	N/A	$ -	$ -	$ 1.05	6.27%	$ 0.07	$ -	$48.10	$ -	$48.10
Pumped Hydro, Southern OR	N/A	42%	$78.09	N/A	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ -	$78.60
Pumped Hydro, Portland North Coast	N/A	42%	$78.09	N/A	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ -	$78.60
Pumped Hydro, Central WY	N/A	42%	$78.09	N/A	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ -	$78.60
Pumped Hydro, Eastern WY	N/A	42%	$78.09	N/A	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ -	$78.60
Pumped Hydro, Central UT	N/A	42%	$78.09	N/A	$ -	$ -	$ 0.51	0.00%	$ -	$ -	$78.60	$ -	$78.60
Idaho Falls, ID, 20 MW, 26.1% CF	4,700	26%	$41.45	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$41.45	$ -	$41.45
Lakeview, OR, 20 MW, 27.6% CF	4,800	28%	$41.33	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$41.33	$ -	$41.33
Milford, UT, 20 MW, 30.2% CF	5,000	30%	$35.55	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$35.55	$ -	$35.55
Milford, UT, 200 MW, 30.2% CF	5,000	30%	$30.35	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$30.35	$ -	$30.35
Rock Springs, WY, 200 MW, 27.9% CF	6,400	28%	$33.85	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$33.85	$ -	$33.85
Yakima, WA, 200 MW, 24.2% CF	1,000	24%	$39.59	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$39.59	$ -	$39.59
Idaho Falls, ID, 200 MW, 26.1% CF + BESS: 100% pwr, 4 hours	4,700	26%	$92.87	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$92.87	$ (16.12)	$76.75
Lakeview, OR, 200 MW, 27.6% CF + BESS: 100% pwr, 4 hours	4,800	28%	$87.55	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$87.55	$ (16.12)	$71.43
Milford, UT, 200 MW, 30.2% CF + BESS: 100% pwr, 4 hours	5,000	30%	$80.30	N/A	$ -	$ -	$ -	0.00%	$ -	$ -	$80.30	$ (16.12)	$64.17
Rock Springs, WY, 200 MW, 27.9% CF + BESS: 100% pwr, 4 hours	6,400	28%	$87.38	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$88.36	$ (16.12)	$72.23
Yakima, WA, 200 MW, 24.2% CF + BESS: 100% pwr, 4 hours	1,000	24%	$102.55	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$103.52	$ (16.12)	$87.40
Pocatello, ID, 20 MW, CF: 37.1%	4,500	37%	$59.30	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$60.27	$ (16.12)	$44.14
Pocatello, ID, 200 MW, CF: 37.1%	4,500	37%	$47.74	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$48.71	$ (16.12)	$32.58
Arlington, OR, 20 MW, CF: 37.1%	1,500	37%	$59.05	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$60.03	$ (16.12)	$43.90
Arlington, OR, 200 MW, CF: 37.1%	1,500	37%	$47.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$48.10	$ (9.67)	$38.42
Monticello, UT, 20 MW, CF: 29.5%	4,500	30%	$75.22	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$76.19	$ (9.67)	$66.51
Monticello, UT, 200 MW, CF: 29.5%	4,500	30%	$60.79	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$61.76	$ (9.67)	$52.09
Medicine Bow, WY, 20 MW, CF: 43.6%	6,500	44%	$49.90	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$50.88	$ (9.67)	$41.20
Medicine Bow, WY, 200 MW, CF: 43.6%	6,500	44%	$40.11	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$41.08	$ (9.67)	$31.41
Goldendale, WA, 20 MW, CF: 37.1%	1,500	37%	$61.60	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$62.58	$ (16.12)	$46.45
Goldendale, WA, 200 MW, CF: 37.1%	1,500	37%	$49.04	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$50.01	$ (16.12)	$33.89
Offshore, Northern, CA, CF: 47.0%	0	47%	$103.63	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$104.60	$ (13.36)	$91.24
Offshore, Northern, CA, 1GW, CF: 47.0%	0	47%	$103.59	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$104.56	$ (13.36)	$91.20
Pocatello, ID, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	4,500	37%	$93.96	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.97	$94.93	$ (11.56)	$83.37
Arlington, OR, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	37%	$97.36	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$98.09	$ (12.17)	$85.92
Monticello, UT, 200 MW, CF: 29.5% + BESS: 100% pwr, 4 hours	4,500	30%	$120.39	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$121.13	$ (14.94)	$106.19
Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 100% pwr, 4 hours	6,500	44%	$83.84	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$84.57	$ (10.53)	$74.04
Goldendale, WA, 200 MW, CF: 37.1% + BESS: 100% pwr, 4 hours	1,500	37%	$177.50	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$178.23	$ (26.46)	$151.77
Offshore, Northern, CA, CF: 47.0% + BESS: 100% pwr, 4 hours	0	47%	$133.52	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$134.25	$ (16.71)	$117.54
Idaho Falls, ID Solar + Wind + BESS: 100% pwr, 4 hours	4,700	26%	$239.89	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$240.63	$ (30.09)	$210.53
Lakeview, OR Solar + Wind + BESS: 100% pwr, 4 hours	4,800	28%	$233.93	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$234.66	$ (29.71)	$204.95
Milford, UT Solar + Wind + BESS: 100% pwr, 4 hours	5,000	30%	$218.41	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$219.15	$ (27.99)	$191.16
Rock Springs, WY Solar + Wind + BESS: 100% pwr, 4 hours	6,400	28%	$221.89	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$222.62	$ (27.70)	$194.92
Yakima, WA Solar + Wind + BESS: 100% pwr, 4 hours	1,000	24%	$261.94	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$262.68	$ (33.02)	$229.66
Dual Flash Expansion of Blundell Plant	4,500	90%	$44.60	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$45.33	$ (16.12)	$29.21
Greenfield Binary Plant	4,500	90%	$58.08	n/a	$ -	$ -	$ -	0.00%	$ -	$ 0.74	$58.82	$ (16.12)	$42.69
Small Modular Reactor x 12	5,000	86%	$60.19	N/A	$ -	$ -	$ 7.11	0.00%	$ -	$ 0.74	$68.03	$ (5.98)	$62.05

Table 7.3 - Glossary of Terms from the Supply-Side Resource Table

Term	Description
Fuel	Primary fuel used for electricity generation or storage.
Resource	Primary technology used for electricity generation or storage.
Elevation (afsl)	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW)	For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition.
Commercial Operation Year	The resource availability year is the earliest year the technology associated with the given generating resource is commercially available for procurement and installation. The total implementation time is the number of years necessary to implement all phases of resource development and construction: site selection, permitting, maintenance contracts, IRP approval, RFP process, owner's engineering, construction, commissioning and grid interconnection.
Design Life (years)	Average number of years the resource is expected to be "used and useful," based on various factors such as manufacturer's guarantees, fuel availability and environmental regulations.
Base Capital ($/kW)	Total capital expenditure in dollars per kilowatt-hour ($/kW) for the development and construction of a resource including: direct costs (equipment, buildings, installation/overnight construction, commissioning, contractor fees/profit and contingency), owner's costs (land, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, owner's contingency), and financial costs (allowance for funds used during construction (AFUDC), capital surcharge, property taxes and escalation during construction, if applicable).
Var O&M ($/MWh)	Includes real levelized variable operating costs such as combustion turbine maintenance, water costs, boiler water/circulating water treatment chemicals, pollution control reagents, equipment maintenance and fired hour fees in dollars per megawatt hour ($/MWh).
Fixed O&M ($/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment and training.
Demolition Cost ($/kW)	Total cost to decommission and demolish the generating unit at the end of life in dollars per kilowatt ($/kW).
Full Load Heat Rate HHV (Btu/kWh)	Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis.
EFOR (%)	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates for a given resource at the given site.
POR (%)	Estimated Planned Outage Rate for a given resource at the given site.

Term	Description
Water Consumed (gal/MWh)	Average amount of water consumed by a resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO_2 (lbs/MMBtu)	Expected permitted level of sulfur dioxide (SO_2) emissions in pounds of sulfur dioxide per million Btu of heat input.
NOx (lbs/MMBtu)	Expected permitted level of nitrogen oxides (NO_x) (expressed as NO_2) in pounds of NOx per million Btu of heat input.
Hg (lbs/TBtu)	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO_2 (lbs/MMBtu)	Pounds of carbon dioxide (CO_2) emitted per million Btu of heat input.

Table 7.4 - Glossary of Acronyms Used in the Supply-Side Resources

Acronyms	Description
AFSL	Average Feet (Above) Sea Level
ATB	Annual Technology Baseline
CAES	Compressed Air Energy Storage
CCCT	Combined Cycle Combustion Turbine
CCUS	Carbon Capture, Utilization and Storage
CF	Capacity Factor
CSP	Concentrated Solar Power
DF	Duct Firing
IC	Internal Combustion
IGCC	Integrated Gasification Combined Cycle
ISO	International Organization for Standardization (Temp = 59 F/15 C, Pressure = 14.7 psia/1.013 bar)
Li-Ion	Lithium Ion
LFP	Lithium Iron Phosphate (sub-chemistry of lithium-ion)
NCM	Nickel Cobalt Manganese (sub-chemistry of lithium-ion)
OSW	Offshore Wind
PPA	Power Purchase Agreement
PC CCUS	Pulverized Coal retrofitted with Carbon Capture, Utilization and Storage
PHES	Pumped Hydro Energy Storage
PV Poly-Si	Photovoltaic modules constructed from poly-crystalline silicon semiconductor wafers
Recip	Reciprocating Engine
SCCT	Simple Cycle Combustion Turbine

Resource Option Descriptions

The following are brief descriptions of each of the resources listed in Table 7.1.

Natural Gas, Simple Combined Cycle Turbine (SCCT) Aero x 4 – a resource based on four General Electric simple cycle aero-derivative combustion turbines fueled on natural gas. The scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/volatile organic compounds (VOC) emissions.

Natural Gas, SCCT Frame "J" x 1 – a resource based on one General Electric 7HA.02 simple cycle frame type combustion turbine fueled by natural gas. Scope would not include selective catalytic reduction systems to reduce NOx emissions because the engines can meet the emissions requirements with the expected capacity factor.

Brownfield SCCT Frame "J" x1 - a resource located at an existing generating facility based on one General Electric 7HA.02 simple cycle frame type combustion turbine fueled by natural gas. Scope would not include selective catalytic reduction systems to reduce NOx emissions because the engines can meet the emissions requirements with the expected capacity factor.

Natural Gas, SCCT Frame "J" x 1, 30H2 – a resource based on one General Electric 7HA.02 simple cycle frame type combustion turbine fueled by 30 percent hydrogen and 70 percent natural gas. Scope would not include selective catalytic reduction systems to reduce NOx emissions because the engines can meet the emissions requirements with the expected capacity factor.

Natural Gas, SCCT Frame "J" x 1, 100H2 – a resource based on one General Electric 7HA.02 simple cycle frame type combustion turbine fueled by 100 percent hydrogen. Scope would not include selective catalytic reduction systems to reduce NOx emissions because the engines can meet the emissions requirements with the expected capacity factor.

Natural Gas, CCCT Dry "J", 1x1 – a combined cycle resource based on one frame-type General Electric 7HA.02 combustion turbine (air-cooled), one 3-pressure heat recovery steam generator and one steam turbine. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. Steam from the steam turbine is condensed in an air-cooled condenser.

Coal, PC CCUS Oxy-Combustion retrofit at 100 MW pre-retrofit – a retrofit of an existing conventional coal-fueled boiler and steam-turbine generator resource with an oxy-combustion carbon capture technology. Costs include the reduction in plant output due to increased auxiliary power requirements. The CCUS would remove above 95 percent of the carbon dioxide and would provide reductions in other emissions.

Coal, PC CCUS at 330 MW pre-retrofit – a retrofit of an existing conventional coal-fired boiler and steam-turbine generator resource with a post-combustion carbon capture technology. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output. The CCUS would remove 90 percent of the carbon dioxide and would provide reductions in other emissions.

Coal, PC CCUS at 700 MW pre-retrofit – a retrofit of an existing conventional coal-fired boiler and steam-turbine generator resource with a post-combustion carbon capture technology. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output. The CCUS would remove 90 percent of the carbon dioxide and would provide reductions in other emissions.

Wind, 37 percent Net Capacity Factor (NCF) WA/OR/ID – a wind resource based on 3.4 MW wind turbines located in Washington, Oregon, or Idaho with an estimated annual net capacity factor of 37.1 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Wind, 29 percent NCF UT – a wind resource based on 3.4 MW wind turbines located in Utah with an estimated annual net capacity factor of 29.5 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Wind, 43 percent NCF WY – a wind resource based on 3.4 MW wind turbines located in Wyoming with an estimated annual net capacity factor of 43.6 percent.

Wind, Offshore Northern California, 47 percent NCF – a wind resource based on 6.0 MW wind turbines located off the coast of northern California or southern Oregon with an estimated annual net capacity factor of 47.0 percent.

Wind + Energy Storage – a wind resource as described above paired with a 4-hour battery with 100% of the power capacity of the wind resource. The batteries paired with wind resources in the previous IRP had 50% of the power of the wind resources.

Solar, PV Single Axis Tracking in ID, OR, UT, WA, and WY with NCF between 24.2 and 30.2 percent depending upon location (1.30 MWdc/MWac) – a large utility scale (20 MW or 200 MW) solar photovoltaic resource using crystalline silica solar panels in a single axis tracking system located in Idaho Falls, Idaho; Lakeview, Oregon; Milford, Utah; Rock Springs, WY; and Yakima, Washington.

Solar + Energy Storage – a solar resource as described above paired with a 4-hour battery with 100% of the power capacity of the solar resource. The batteries paired with solar resources in the previous IRP had 50% of the power of the solar resources.

Storage, Pumped Hydro Storage – a nominal 400 MW PHES system using a combination of natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for 10 hours combined with recharging that capacity over 14 hours. Total development time is estimated at 10 years due to permitting and construction durations. The total round-trip efficiency for this resource is projected to be 78 percent.

Storage, Lithium Ion Battery –lithium-ion batteries rated at 200, 500, and 1,000 MW capacities with 4-hour duration. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year. The total round-trip efficiency for this resource is projected to be 83 percent.

Incremental, double energy capacity – to double the duration of the energy storage resource in the preceding row, costs on this row must be added to the costs in the row above.

Storage, Flow Battery – a battery utilizing electrolyte solution that changes its chemical state when flowing through a cell. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year. The total round-trip efficiency for this resource is projected to be 70 percent.

Storage, Adiabatic CAES – compressed air energy storage (CAES) system consists of air storage reservoir pressurized by a compressor similar to a conventional gas turbine compression section but driven by an electric motor coupled with an adiabatic power generation turbine. The compressed air powers the adiabatic turbine. Energy is stored by compressing air into the storage reservoir. System sizes of 125, 250 and 500 MW are assumed. The air storage reservoir is assumed to be solution mined to size for the indicated MWh of energy storage. No natural gas is required to generate power. The total round-trip efficiency for this resource is projected to be 69 percent. The CAES resource modeled in the 2019 and prior IRPs was a diabatic system which differed from this resource in that it required burning fuel in the power generation turbine similar to a gas turbine engine.

Storage, One-hundred-hour duration -
Nuclear, Small Modular Reactor – such systems hold the promise of being built off-site and transported to a location at lower cost than traditional nuclear facilities. A nominal 854 MW concept is included. It is recognized that this concept is still in the design and licensing stage and is not commercially available requiring approximately 7 years for availability.

Resource Types

Renewables
PacifiCorp retained WSP to evaluate various renewable energy resources in support of the development of the 2023 IRP and associated resource acquisition portfolios and/or products. The WSP Assessment (Volume II, Appendix M) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and O&M costs that are representative of renewable energy and storage technologies listed below. The Assessment contains preliminary information in support of the long-term power supply planning process. Any technologies of interest to PacifiCorp shall be followed by additional detailed studies during procurement proposal evaluation to further investigate each technology and its direct application within the owner's long-term plans. The following technologies are addressed in the WSP Assessment.

- Geothermal
- Solar
- Wind
- Energy Storage
    - Lithium-Ion Battery
    - Flow Battery
    - Gravity Battery
    - Compressed Air
- Solar + Energy Storage
- Wind + Energy Storage
- Wind + Solar + Energy Storage

Each renewable resource is defined within the Assessment. General assumptions, technology specific assumptions and cost inclusions and exclusions are described within the Assessment. The following paragraphs discuss highlights from the Assessment, a comparison to previous IRP data and additional assessment performed by PacifiCorp.

Costs
The following costs which were excluded from the renewables costs estimates were added by PacifiCorp:

- AFUDC
- Escalation
- Sales tax
- Property taxes and insurance
- Utility demand costs

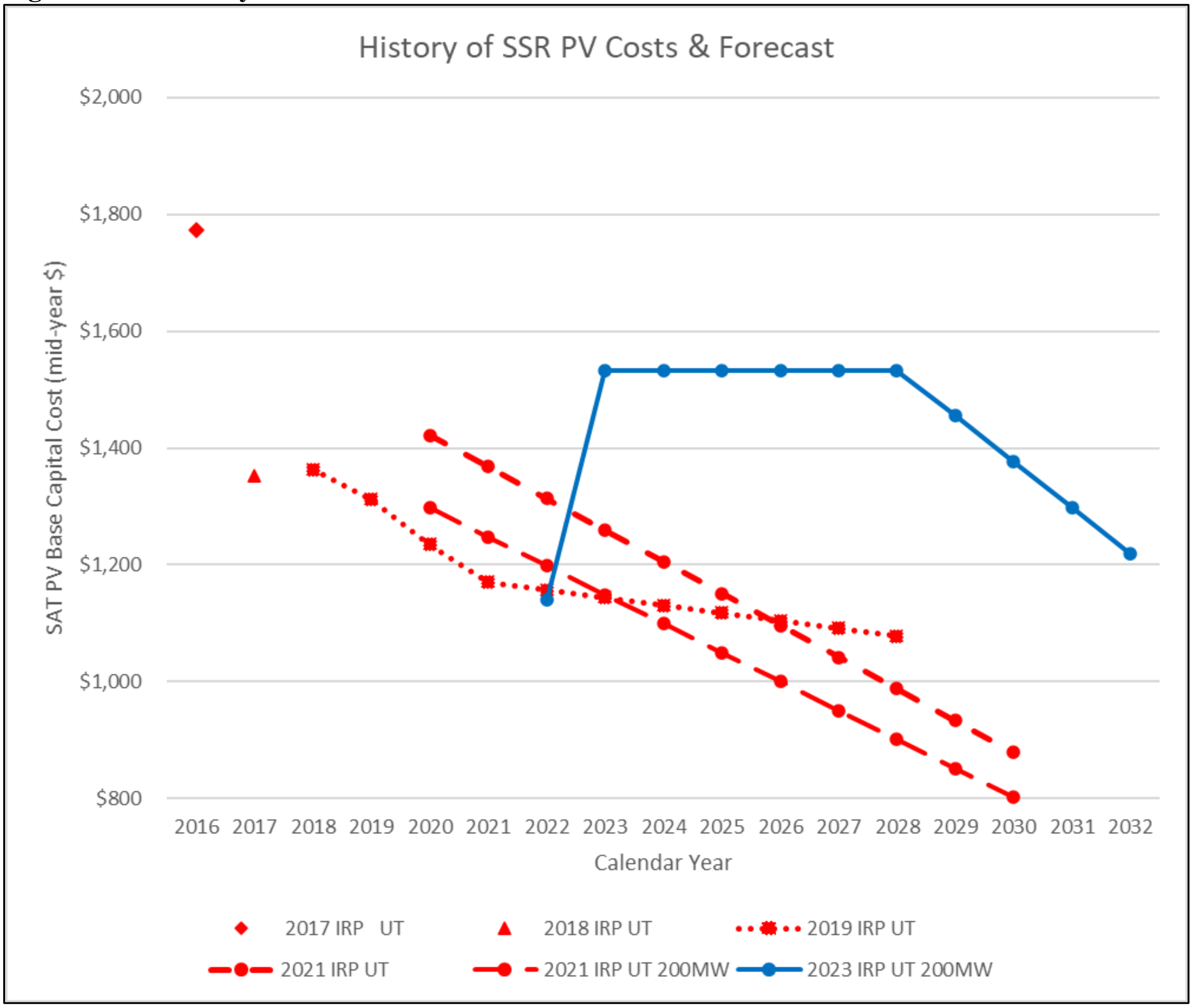
Solar
The WSP Assessment includes 20 MW, and 200 MW single axis tracking (SAT), PV options evaluated at five locations within the PacifiCorp services area. The 2023 IRP differs from the previous IRP in the following ways:

- The 100 MW option was removed as most bids in response to Company Requests for Proposals in the near future are expected to leverage advantages at the 200 MW size.
- 20 MW options were added to comply with Washington regulation WAC 480-100-620, as well as Oregon House Bill 2021, which expanded a requirement for small-scale renewables of up to 20 MW.

Initially, 2022 solar cost estimates used for the 2023 IRP closely matched the forecasted costs from the 2021 IRP. However recent global changes appear to have driven up capital costs for solar PV generation projects. Three events are believed to have significantly contributed to the increase in cost: 1) inflation, 2) higher demand largely due to Inflation Reduction Act incentives, and 3) trade restrictions intended to discourage unethical labor practices, particularly in China where most of the market's crystalline panels are produced.

Figure 7.3 shows a history of capital cost forecasts used in the SSR for PV resources in Utah. The 2023 IRP Capital cost estimates for solar resources are based upon a combination of information sources including the WSP Assessment, recent studies from NREL and others, and from PacifiCorp's experience. The red lines show the forecasts from previous IRP's. The data from IRP's prior to 2021 was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The solid blue line indicates the 2023 IRP price forecast at the 200 MW scale. The sharp increase from 2022 to 2023 represents the observed market correction. The cost increase is assumed to remain in place until panel producers fulfill all back-orders, and increase manufacturing capability to keep up with market demand.

Figure 7.3 – History of SSR PV Cost & Forecast



Wind

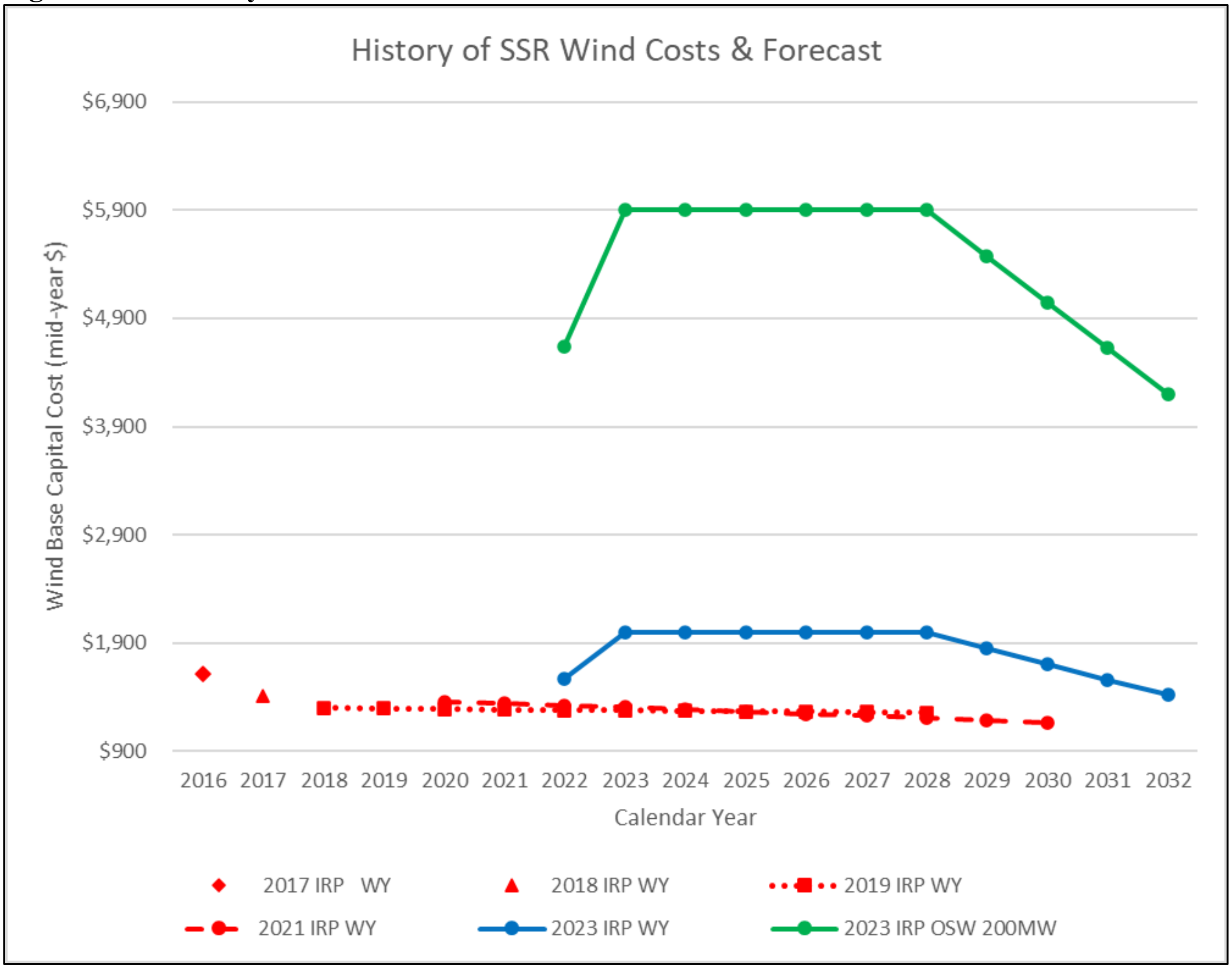
Wind energy has been one of the most cost-effective new generation resources for PacifiCorp's customers in recent IRPs and was the largest source of new resource commitments in PacifiCorp's recently completed 2020 All-Source Request for Proposals. PacifiCorp has also committed to repower two existing wind sites, combining prime geographic locations with existing transmission infrastructure with updated technology. The wind market knowledge PacifiCorp gained and continues to gain from these wind projects has been combined with the information in the WSP Assessment to inform the wind costs in the 2023 IRP.

The WSP Assessment uses a 200 MW project size that can be realized within most wind development areas in PacifiCorp's service territory and large enough to achieve economies of scale. The net capacity factors for onshore wind generating facilities in the states of Idaho, Oregon, Utah, Washington, and Wyoming reflect strong wind resources that are achievable within or near PacifiCorp's service areas. Generic project locations were selected by the company based on viable wind project locations where there are favorable wind profiles. All wind resources are specified in 200 MW blocks, but the model can choose multiple blocks or a fractional amount of a block.

Offshore Wind

PacifiCorp added offshore wind as a resource in the SSR for the 2023 IRP. A 200 MW option is included for comparison to the onshore 200 MW size, and for potential modeling in a scenario without extensive onshore transmission upgrades. A 1,000 MW option is included for modeling in a potential scenario which would require extensive onshore transmission system upgrades. The solid green line in Figure 7.4 shows the higher capital cost of offshore wind versus onshore wind. The cost difference between the 200 MW and 1,000 MW resource options is imperceivable on this graph and does not include on-shore transmission upgrades as those costs are location dependent. Offshore wind holds the promise of high production capacity but faces various risks and costs that are higher than onshore wind projects. The most promising offshore wind regimes are located approximately 10 to 20 miles from the coast and will require underwater electric transmission lines to connect to the shore. New offshore wind projects will have to bear the cost of underwater transmission lines and any land-based transmission upgrades that are required to interconnect the project to the grid. Offshore wind turbines along the Pacific coast will need to be built on floating bases due to water depths that are hundreds of meters deep, as compared to offshore wind developments in shallower waters along the Atlantic coast. Floating offshore wind turbines are much less common than seabed-mounted offshore wind turbines that can be built in ocean waters up to 60 meters deep. Interest in offshore wind along the Pacific coast has increased during the past IRP cycle and the advancement of two areas for offshore wind development along the coast of California by the US Department of the Interior was a significant step forward in the development process.

Figure 7.4 – History of SSR Wind Costs & Forecast



Geothermal

Geothermal resources can produce base-load energy and have high reliability and availability. However, geothermal resources have significantly higher development costs and exploration risks than other renewable technologies such as wind and solar. PacifiCorp has commissioned several studies of geothermal options during the past ten plus years to determine if additional sources of production can be added to the company's generation portfolio in a cost-effective manner. A 2010 study commissioned by PacifiCorp and completed by Black & Veatch focused on geothermal projects near PacifiCorp's service territory that were in advanced phases of development and could demonstrate commercial viability. PacifiCorp commissioned Black & Veatch to perform additional analysis of geothermal projects in the early stages of development and a report was issued in 2012. An evaluation of the PacifiCorp's Roosevelt Hot Springs geothermal resource was commissioned in 2013. The geothermal costs in the 2023 supply side resource option were developed by WSP's geothermal experts in New Zealand and reflect some potential cost reductions from recent and on-going advancements in geothermal resource exploration and development.

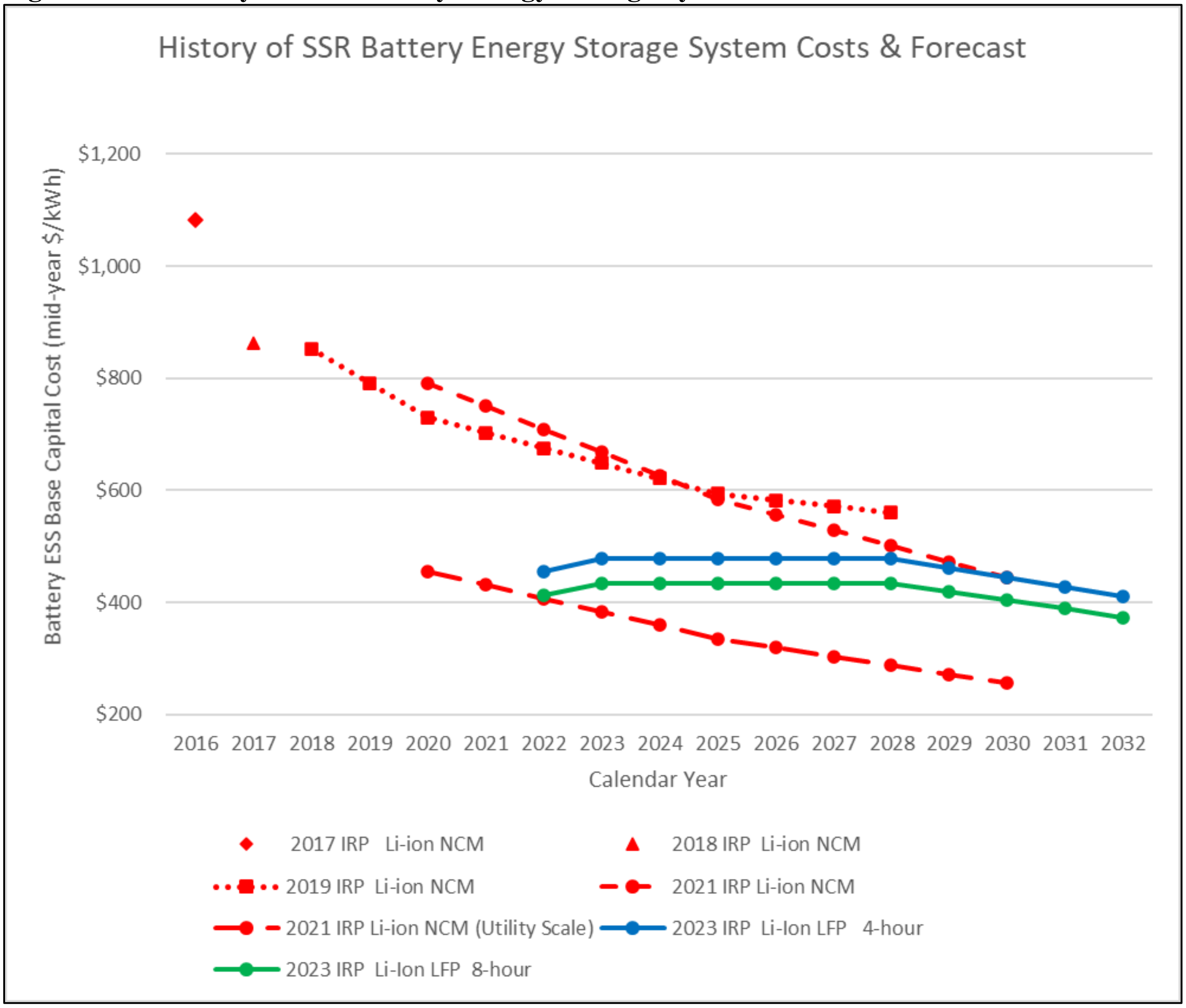
The cost recovery mechanisms currently available to PacifiCorp as a regulated electric utility are not compatible with the inherent risks associated with the development of geothermal resources for power generation. The primary risks of geothermal development are dry holes, well integrity and insufficient resource adequacy (flow, temperature, and pressure). These risks cannot be fully quantified until wells are drilled and completed. The cost to validate total production capability of a geothermal resource can be as high as 35 percent of total project costs. Exploration test wells typically cost between $500,000 and $1.5 million per well. Full production and injection wells cost between $4-5 million per well. Variations in the permeability of subsurface materials can determine whether wells in proximity are commercially viable, lacking in pressure or temperature, or completely dry with no interconnectivity to a geothermal resource. As a regulated utility subject to the public utility commissions of six states, PacifiCorp is not compensated nor incentivized to engage in these inherently risky development efforts.

To mitigate the financial risks of geothermal development, PacifiCorp would use an RFP process to obtain market proposals for geothermal power purchase agreements or build-own-transfer project agreement structures. Geothermal developers, external to PacifiCorp, have the flexibility to structure project pricing to include all development risks. Through an RFP process, PacifiCorp could choose the geothermal project with the lowest cost offered by the market and avoid considerable risk for the company and its customers. Several geothermal projects submitted proposals in response to the 2016 Oregon Renewables RFP, but none of the geothermal projects were selected by PacifiCorp. In the event PacifiCorp identifies a geothermal asset that appears to be economically attractive but also determines that there is a significant possibility of development risk that the market will not economically absorb, PacifiCorp may approach state regulators with estimates of resource development costs and risks associated to obtain approval for a mechanism to address risks such as dry holes. Because public utility commissions typically do not allow recovery of expenditures which do not result in a direct benefit to customers, and at least one state has a statute that precludes cost recovery of any asset that is not considered to be “used and useful,” obtaining a mechanism to recover geothermal development costs may be difficult.

Energy Storage

The WSP Assessment discusses four energy storage resource options: 1) lithium-ion batteries, 2) flow batteries, 3) gravity batteries (other than pumped hydro), and 4) compressed air energy storage (CAES). Lithium-ion battery storage was also considered in combination with solar and wind. Due to on-going confidential discussions with pumped hydro project developers, pump hydro was simplified in the 2023 IRP with a standard 400 MW resource for all locations. The details were developed internally and are intended to represent a reasonable option within the IRP modeling, while maintaining neutrality among the specific projects within PacifiCorp territory. PacifiCorp worked with both WSP and Renewable Energy Storage Company, LLC (a developer of an adiabatic CAES project within PacifiCorp’s territory. The costs appear to be competitive with the CAES option modeled in the 2021 IRP. No forecasts have been used for pumped hydro and CAES. Both technologies are expected to have a flat forecast escalating at the standard inflation rate used in the IRP modeling.. Figure 7.5 shows a history of capital costs on a per MWh *energy capacity* basis (note that similar graphs for other resources are on a per kW *power capacity* basis) and forecasts used in the SSR for Li-Ion battery resources. The solid lines indicate the 2022 price and forecast at the 200 MW scale considered for the 2023 IRP at 4-hour duration in blue and an 8-hour duration in green. The 200 MW capacity is in an increase from the 50 MW capacity used in the 2021 IRP, as projects at the 200 MW scale are being proposed in RFP’s. Like solar project costs, battery project costs appear to have increased due to inflation and increased demand, but do not seem to have been significantly impacted by trade restrictions.

Figure 7.5 – History of SSR Battery Energy Storage System Costs & Forecast



PacifiCorp and its Berkshire Hathaway Energy affiliates continuously monitor and evaluate technical developments in the utility power industry, including energy storage technologies (lithium-ion and flow batteries, pumped storage hydro and hybrid energy-storage solutions), nuclear and carbon capture technologies. With the ever-advancing technological developments, market conditions, and regulatory environment, it is critical that PacifiCorp understand when developing technologies and other opportunities become sufficiently established in the marketplace that they can be implemented with minimal risk to PacifiCorp's system customers.

PacifiCorp also leverages the broader Berkshire Hathaway Energy platform of companies including NV Energy and MidAmerican Energy to collaborate and share experiences and lessons learned regarding battery energy storage technology and capturing the value of energy storage. NV Energy has been a leader in battery storage.

In addition to leveraging the experience of its peer utilities, PacifiCorp has engaged the expertise of market-leading 3rd party technical experts including WSP, Black & Veatch, Power Engineers, DNV, FlexGen, Tesla, Powin, ESS, Lion, Form, Uni Energy Technologies and other leading battery consultants and suppliers to develop its proxy resource assumptions, develop its procurement specifications, evaluate bidders, develop benchmark projects, and design and construct utility-owned transmission and distribution facilities.

In 2021, PacifiCorp's IRP process identified over 6,000 megawatts of battery storage as a part of its least-cost portfolio through 2040. Leading up to the inclusion of battery storage in the 2022 All-Source Request for Proposals, PacifiCorp updated the standard specifications, and system control schemes for battery storage facilities. In the request for proposal, PacifiCorp outlined battery storage use cases and required functionality to ensure battery storage proposal value was captured through battery energy storage bids. Finally, PacifiCorp engaged outside legal expertise in negotiating contracting terms and conditions with short-listed bidders in the 2020 all-source RFP to further mitigate delivery risk to its customers.

PacifiCorp procurement and operational experience with battery storage projects

PacifiCorp completed the Panguitch Solar and Battery Storage project in Utah in 2020 as a utility-owned and operated transmission and distribution upgrade deferral project. In 2019-2020, PacifiCorp partnered with Sonnen, Inc. and the Wasatch Group to complete The Soleil Lofts Residential Apartment Project, a network of solar powered battery storage systems for the benefit of the apartment community and PacifiCorp's customers. PacifiCorp continues work towards completing the development and design for a project in Oregon to install a battery storage project at the Oregon Institute of Technology in Klamath Falls, which is scheduled for completion in 2023. These three projects demonstrate the capability and validate the value battery storage provides to the electrical grid through peak shifting to defer the cost to upgrade regional transmission and distribution lines, and other energy storage value cases. PacifiCorp had complete turnkey responsibility for the Panguitch Solar and Battery Storage facility and will similarly be responsible for the Oregon Institute of Technology facility. The Soleil Lofts facilities were developed, constructed and owned by a 3rd party, but are being dispatched by PacifiCorp's Energy Supply Management Group for the benefit of PacifiCorp's system. Leveraging lessons learned from the Soleil Lofts project, PacifiCorp's Wattsmart program added batteries to its Savings & Energy Choices.

The 2020 and 2022 All Source (AS) Requests for Proposal (RFP) have requested and received multiple utility scale battery energy storage system (BESS) bids. For the 2020 AS RFP, no standalone battery storage contracts were executed. For the 2022 AS RFP the PacifiCorp benchmark team has prepared and submitted four standalone BESS and four solar-plus-battery projects with over 1,200 MW of power capacity. The RFP evaluation team has received third party standalone BESS and solar-plus-battery bids from multiple counterparties representing more than 5,000 MW of storage capacity.

Panguitch Solar and Battery Storage Project

To correct voltage issues experienced during peak loading conditions on a portion of PacifiCorp's system in southern Utah, a stationary battery system and photovoltaic solar array was installed on a distribution circuit out of the Panguitch substation located in Garfield County, Utah. This project will alleviate peak loading on the power transformer, improve voltage conditions, and defer costs associated with upgrading the upstream 69-kV sub-transmission system under a traditional poles and wires build-out. The Panguitch project was a 650-kilowatt photovoltaic solar field and one megawatt, five-hour battery system in central Utah. PacifiCorp with Black & Veatch and battery supplier FlexGen developed multiple operating modes to demonstrate the full range and capabilities of 684 Samsung lithium-ion batteries and how different control modes affect energy system operation.

The Utah Public Service Commission approved the Panguitch battery storage project (1 MW, 5 MWh) under the Sustainable Transportation and Energy Plan/Utah Innovative Technologies (STEP/UIT) program December 29, 2016. The solar photovoltaic component (650 kW) of the project was separately funded by the company's Blue Sky program. PacifiCorp completed the purchase of a ten-acre project site in October 2017. Construction began in July 2019 and was completed in late 2019. Commercial operations began in 2020.

Since commercial operations began, the company has worked with the battery provider to refine the control algorithms to enable charging of the battery only from the on-site solar generation facility. The company is currently collecting solar and battery charge/discharge data from the site to further optimize operational performance.

Soleil Lofts Residential Apartment Project

Soleil Lofts, located in Herriman, Utah is an all-electric, net-zero development, designed to generate as much electricity as it uses through rooftop solar panels backed up with battery storage. PacifiCorp collaborated with the Soleil Lofts residential apartment project to develop a behind the meter application of battery systems. This project is the largest utility-managed residential battery demand response solution in the United States. PacifiCorp with Sonnen, Inc. and the Wasatch Group completed a network of solar powered battery storage systems for the benefit of the apartment community and PacifiCorp's customers. The project features over 630 individual Sonnen ecoLinx batteries, totaling 12.6 MWh of solar energy storage that is managed by PacifiCorp. The batteries provide emergency back-up power, daily management of peak energy use, and demand response for the overall management of the electric grid and demonstrating a way to expand residential renewable power capacity.

Wattsmart Battery Program

This innovative program is intended to solve some of today's challenges to help create a healthier environment and use renewable energy effectively while setting the foundation to evolve with technology and customer needs as we transition to a more renewable energy future. It is a voluntary program available to all Rocky Mountain Power customers who purchase and install a qualifying battery and who meet all program requirements. Program benefits include an upfront enrollment incentive plus ongoing bill credits while enabling back-up power. Qualified batteries will be connected to the electric grid through a customer generation meter, allowing Rocky Mountain Power to manage the battery to keep the grid reliable, resilient and secure. The program will evolve based on the lessons learned and the need to ensure sustainability for the long term. More information is available at rockymountainpower.net/battery.

Oregon Institute of Technology

Oregon House Bill (HB) 2193, passed in June of 2015 directed electric companies in Oregon to identify and evaluate potential energy storage technologies. PacifiCorp has commenced a project to engineer, design, procure, interconnect, and commission a 2 MW (6 MWh) battery storage project on the campus of the Oregon Institute of Technology ("OIT") in Klamath Falls, Oregon. Design and procurement activities are underway in parallel with the generation interconnection review process. The project is expected to go into service in 2023. PacifiCorp has contracted Power Engineers as the Engineer of Record, and has contracted with POWIN for the

BESS supply. Once the design is complete a construction contractor will be selected via competitive bid. PacifiCorp's engineering and management team are also working with OIT to provide a student learning experience once the system is operational.

Outside Engineering Support for Battery Storage Procurement and Operations

In preparation for the 2020 and 2022 all-source requests for proposal which resulted from the resource need action items in the 2019 and 2021 IRP processes, PacifiCorp engaged WSP to 1) develop preferred use case and technical specifications for collocated and stand-alone storage resource bids, 2) evaluate the technical bid responses, 3) update the generating-resource power purchase agreements to include battery storage terms and conditions and relevant exhibits needed for a collocated resource and storage power purchase agreement, and 4) provide cost and technical information and reports for renewable resources included in the 2023 IRP,.

WSP is a globally recognized professional services firm with a 130-year history. WSP's primary inputs have been in a supporting role, assisting in the development of revised specifications for wind and solar farm equipment and installations including accompanying battery storage facilities. Specific to battery storage, WSP has been influential in assisting PacifiCorp in the development of Li-battery specifications and has participated in the development of operating and contractual parameters that will become part of our revised power purchase agreement contract template in the 2020AS RFP contracting process.

PacifiCorp has actively monitored developments in battery storage since 2009 with support through the broader Berkshire Hathaway Energy platform of companies including NV Energy and MidAmerican Energy and through the engagement of market-leading companies like WSP, Black & Veatch, Burns & McDonnel, DNV, Power Engineers, FlexGen, Tesla, Sonnen, ESS Inc., Lion Energy, and Uni Energy Technologies. Further, PacifiCorp is actively evaluating and pursuing new control systems that will both integrate and optimize battery storage, and other electronically controlled distributed assets, to further assure both maximum customer benefit and improved system flexibility and stability for years to come. With each new battery storage resource added to our system, we gain additional depth and experience that we then apply to the next cycle of integrated resource planning and subsequent resource procurement.

Natural Gas

Natural gas-fueled generating resources offer several important services that support the safe and reliable operation of the energy grid in an economic manner. They include technologies that are capable of providing firming, peaking, intermediate and base generation.

A variety of natural gas-fueled generating resources are included in the SSR. The variety of natural gas resources were selected to provide for generating performance and services essential to safe and reliable operation of the energy grid. Performance, cost and operating characteristics for each resource were provided at elevations of 1,500, 3,000, 5,050 and 6,500 feet above mean sea level, representative of geographic areas in which the resource could be located. Performance, cost and operating characteristics were also provided at zero feet above mean sea level and 59 °F (ISO conditions) as a reference. The essential services provided by the resource are firming for variable energy resources, intermediate and base generation.

Two simple cycle combustion turbine options, and 3 simple cycle with hydrogen options, could provide peaking generating services. Peaking generating services require the ability to start and reach near full output in less than ten minutes. Peaking generating services also require the ability in increase (ramp up) and decrease (ramp down) very quickly in response to sudden changes in power demand as well as increases and decreases in production from intermittent power sources. Peaking generation provide the ability to meet peak power demand that exceed the capacity of intermediate and base generation. Peak generation also provide reserves to meet system upsets.

A combined cycle combustion turbine option could provide firming, intermediate and base generating service. Firming generating service requires resources that can increase and decrease generation to replace decreases and increases in generation from variable energy resources. Intermediate generating service requires resources that can efficiently operate at production rates well below full production in compliance with air emissions regulations for long periods of time. Intermediate generating service also require the ability to change production rates quickly. Intermediate generation services provide power demand that is greater than base load and lower than peak demands. Base generating service requires a resource that can operate at full production for long periods of time. Base generation provides for the minimum level of power demand over a day or longer period at a low cost.

Options for intermediate and base generation were based on the “J” size represented by the GE HA.02. Each engine was arranged in a one combustion turbine to one steam turbine (1x1) configuration. Installation of oxidation catalysts for CO control and SCR systems for NOx control is expected. All the combined cycle options included dry cooling allowing them to be located in areas with water resource concerns.

Duct Firing (DF) of the combined cycle is shown in the SSR table. Duct firing is a low-cost option to add peaking capability to a combined cycle at relatively high efficiency and also a mechanism to recover lost power generation capability at high ambient temperatures. In practice the amount of duct firing is a design consideration which is selected during the development of combined cycle generating facilities. In the 2023 IRP, the basic “J” turbines are assumed to be sized such that adding duct firing would result in a negligible capital cost increase, therefore duct firing was included in the combined cycle costs shown in the SSR table, but listed on a separate line to show the distinct operating characteristics it offers.

While equipment provided by specific manufacturers were used to for cost-and-performance information in the SSR table, more than one manufacturer produces these types of equipment. The costs and performance used here is representative of the cost and performance that would be expected from any of the manufacturers. Final selection of a manufacturer’s equipment would be made based on a bid process.

Coal

Coal resources in the 2023 SSR table include three supercritical pulverized coal (PC) Carbon Capture, Utilization and Storage (CCUS) retrofit options located in Wyoming. The standard design technology for PC boilers is supercritical technology (compared to subcritical). Supercritical technology is generally more cost-effective because it has a higher efficiency (resulting in a lower overall emissions intensity), has better load following capability, faster ramp rates, uses less water and requires less steel for construction. As such, there is a greater competitive marketplace for large supercritical boilers than for subcritical boilers, and large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. A new coal-fueled generating facility would be subject to carbon dioxide emissions limits (1,400 lbs per megawatt-hour gross) under the Federal New Source Performance Standards (NSPS) for Greenhouse Gases (GHG). These emission limits are only achievable if a coal-fueled generating facility is equipped with CCUS technology;

however, this imposes a significant cost for both new and existing coal resources. Based on this requirement, only CCUS retrofit options for coal resources are included in the SSR table. The capital and O&M costs for a CCUS retrofit were updated by either escalating corresponding costs used in the 2021 IRP or updating information from existing carbon capture facilities, relevant studies and/or CCUS developers.

Carbon Capture, Utilization and Storage

There are a limited number of commercial-scale carbon capture projects in operation around the world. Most have been installed in conjunction with a planned carbon dioxide end use of injection for EOR. There are only two major utility-scale CCUS retrofit projects on coal plants in North America that have been operated commercially. SaskPower's Boundary Dam Power Station Unit 3 (115 MW net), located in Saskatchewan, Canada, was retrofitted with an amine-based carbon capture system and entered commercial operation in October 2014. The captured carbon dioxide is piped 41 miles to the Weyburn field to be used for EOR. Any carbon dioxide not used for EOR is sequestered at the Aquistore research project. The total cost of the project was approximately $1.24 billion (including approximately $200 million through federal grants). In July 2016, the plant reached a major milestone when it demonstrated that over 1,100,000 tons of carbon dioxide had been captured.

NRG Energy installed a 240 MW equivalent flue gas slipstream amine-based carbon capture system on W.A. Parish Generating Station Unit 8 that went into commercial operation in January 2017. The project, named the Petra Nova Project, was a joint venture between NRG Energy and JX Nippon Oil & Gas Exploration, and cost approximately $1 billion. Approximately $195 million of federal funding in grants was awarded to the project as part of the Clean Coal Power Initiative Program (CCPI), a cost-shared collaboration between the federal government and private industry. The Petra Nova Project included a retrofit of an existing coal-fueled plant using amine-based system and captured approximately 5,200 short tons per day when operating at full capacity.[5] Captured carbon dioxide was transported through an 81-mile pipeline and used for EOR at the West Ranch Oilfield, located on the Gulf Coast of Texas. It is the largest carbon capture retrofit of a pulverized coal plant in the world. The amine-based capture system utilizes Mitsubishi's proprietary KM CDR Process® and uses its KS-1™ amine solvent. Due to low demand for and price of oil in 2020, NRG Energy announced Petra Nova would be placed in a reserve shutdown effective May 1, 2020.[6] In January 2021, the Electric Reliability Council of Texas received a Notification of Suspension of Operations (NSO) for Petra Nova Power.[7] The NSO stated the resource would be mothballed indefinitely as of June 26, 2021.[8]

To address the availability and viability of commercial sequestration near PacifiCorp coal generation resources, three PacifiCorp power plants participated in federally funded research to conduct a Phase I pre-feasibility study, which was awarded in 2016, for carbon capture and storage. A grant from the U.S. Department of Energy (DOE) to the University of Wyoming was used to assess the storage of carbon dioxide in the Rock Springs Uplift, a geologic formation located

[5] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project Final Scientific/Technical Report; March 31, 2020.
[6] Petra Nova status update | NRG Energy
[7] W-A012721-01 Notification of Suspension of Operations (NSO) for Petra Nova Power I LLC (PNPI_GT2) (ercot.com)
[8] A March 2021 notice was issued, moving up the date to suspend operations to June 1, 2021. W-A012721-03 Date of suspension of operations changed - Indefinite Mothball Status of Petra Nova Power I LLC (PNPI_GT2) (ercot.com)

adjacent to the Jim Bridger Plant in southwest Wyoming. Similar funding was allocated to the University of Utah to study the feasibility of long-term carbon dioxide storage in the San Rafael Swell near the Hunter and Huntington plants in central Utah. Both projects showed that geological formations exist near the plants that may support carbon sequestration, though further studies would be required. Neither site was selected by the U.S. DOE for an advanced study in the Phase II of the grant program.

PacifiCorp issued a request for expression of interest to potential CCUS counterparties on September 7, 2018. The request focused on possible deployment of CCUS technologies at PacifiCorp's Dave Johnston generating facility, including utilization of EOR. On February 28, 2019, PacifiCorp received Phase I feasibility studies from three respondent parties. On April 23, 2019, the participants were notified they could opt to progress to a Phase II front-end engineering and design (FEED) study at their discretion. Only one of the parties expressed intent to complete a FEED study. No participants received DOE funds to support Phase II studies. PacifiCorp remains open to evaluate any CCUS project proposal that may arise from these efforts.

As part of its ongoing CCUS evaluation, PacifiCorp issued a new request for expression of interest (REOI) for CCUS on June 29, 2021, to identify and engage with any interested parties to explore the feasibility and design of CCUS facilities to remove carbon dioxide from exhaust gases for PacifiCorp's Wyoming coal-fueled generation, and subsequently utilize and/or sequester all removed carbon dioxide. PacifiCorp received 19 responses from a conglomerate of 60 interested parties.

The Company filed its initial CCUS application for compliance with Wyoming's House Bill 200 and corresponding rules on March 31, 2022. The initial application included a feasibility analysis of CCUS technologies and the Company's coal-fired generation units in Wyoming. The analysis identified Dave Johnston Unit 4 and Jim Bridger Units 3 and 4 as potentially suitable candidates for CCUS and that the Company would further analyze these units in a subsequent request for proposal (RFP) process. The initial application also identified amine solvent based CCUS technology as being the only viable technology to date with the maturity level to be deployed at the scale required by Wyoming's House Bill 200 and administrative rules. The Company issued two CCUS RFPs, one for Jim Bridger Units 3 and/or 4, and one for Dave Johnston Unit 4 on November 1, 2022. Proposals were due March 7, 2023, and PacifiCorp is evaluating information received.

The Commission approved the Company's initial application on November 29, 2022 and directed the Company to consider CCUS proposals based on alternative technology and for alternative sites (Alternative Proposals), update the Company's initial application no later than March 31, 2023, and submit a final plan by March 31, 2024. To comply with Commission directives and to prevent delay to the RFP that was initiated before deliberations occurred, PacifiCorp re-engaged with interested parties on February 24, 2023, requesting information for any advancements to technology, updated cost information, updated partnerships, additional funds for CCUS projects (from the Department of Energy (DOE) or otherwise), any updated proposed CCUS structure(s), or any other information relevant to any of the Company's Wyoming coal units regarding CCUS. Responses were submitted on March 24, 2023, and are being reviewed. The Company also submitted its update to the initial application on March 31, 2023.

Nuclear
PacifiCorp's 2023 IRP includes the Natrium™ advanced nuclear demonstration project: a molten sodium-cooled nuclear reactor paired with a molten salt thermal energy storage tank. Heat from the reactor and the molten salt energy storage is used to generate power through a single steam turbine.

At this time, the specific cost and performance assumptions for the Natrium™ advanced nuclear demonstration project are confidential and are not summarized in the SSR. The demonstration project has three primary elements: a nuclear reactor that produces heat, a molten salt tank to store heat, and a steam generator to convert heat to electricity. Operating characteristics of this facility are summarized as follows:

- 345 MW of baseload energy production at a 92.5% capacity factor
- Maximum output of 500 MW
- Minimum output of 100 MW
- A ramp rate of approximately 40 MW per minute from min to max
- Molten salt storage supports maximum output of 500 MW for a 5.5-hour duration (max output then drops to 345 MW until output is reduced and more heat can be stored)
- Maximum storage efficiency is 99%

In October 2020, the U.S. Department of Energy (DOE), through its Advanced Reactor Demonstration Program (ARDP), awarded TerraPower $80 million in initial funding to demonstrate the Natrium technology. TerraPower signed the cooperative agreement with DOE in May 2021. To date, Congress has appropriated $160 million for the ARDP and DOE has committed additional funding in the coming years, subject to appropriations.

On June 2, 2021, PacifiCorp announced efforts with TerraPower and the U.S. Department of Energy to advance the Natrium™ demonstration project to be sited at a retiring coal plant near, Kemmerer, Wyoming. More information can be found on the Wyoming Advanced Energy webpage at: wyomingadvancedenergy.com. The project features an advanced nuclear reactor developed by TerraPower and GE Hitachi, represented by a 345 MW sodium-cooled fast nuclear reactor with a molten salt-based energy storage system. The energy storage system can increase the project's output to 500 MW for more than five and a half hours when needed. The technology uses structural advancements that separate and simplify major structures, reducing complexity, cost and construction schedule while delivering safe and reliable electricity. The Natrium™ advanced reactor also has enhanced safety features which take advantage of natural forces that do not require human intervention with the ability to shut down independently, indefinitely if needed.

On October 27, 2022, TerraPower and PacifiCorp announced their undertaking of a joint study to evaluate the feasibility of deploying up to five additional Natrium™ reactor and integrated energy storage systems in the PacifiCorp service territory by 2035. The joint study will evaluate, among other things, the potential for advanced reactors to be located near current fossil-fueled generation sites, enabling PacifiCorp to repurpose existing generation and transmission assets for the benefit of its customers. The location of future Natrium™ plants will be thoroughly explored through this study process, and both companies will engage with local communities before any final sites are selected.

Congress and the Department of Energy under the Biden Administration have taken proactive steps to continue to support the deployment of advanced nuclear technologies as part of a suite of solutions aimed at achieving carbon-free goals. With the passage of the Inflation Reduction Act, the bipartisan Infrastructure Investment and Jobs Act, and recent studies on the opportunities of a coal-to-nuclear energy transition, TerraPower and PacifiCorp remain committed to bringing the Natrium™ technology to market and providing reliability and stability to the grid as well as to energy producing communities.

NuScale is developing an advanced reactor design in the Small Modular Reactor (SMR) category. Although it is an FOAK technology, the design has inherent safety features which support reduced capital costs and operating cost estimates. Prior to 2022 PacifiCorp had a seat on the NuScale advisory board; however, PacifiCorp has no monetary interest in NuScale or the SMR project being developed for the Idaho National Lab site. PacifiCorp updated NuScale pricing for the 2023 IRP. Details of NuScale's SMR can be found at www.nuscalepower.com.

Demand-Side Resources

Resource Options and Attributes

Source of Demand-Side Management Resource Data

PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2023-2042, which provided DSM resource opportunity estimates for the 2023 IRP. The study was conducted by Applied Energy Group (AEG) on behalf of the company. The CPA provided a broad estimate of the size, type, location and cost of demand-side resources.[9] For the purpose of integrated resource planning, the DSM information from the CPA was converted into supply curves by type of resource (i.e. energy-based energy efficiency and demand response) for modeling against competing supply-side alternatives.

Demand-Side Management Supply Curves

DSM resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (e.g. products and quantities) based on each resource's competitiveness against alternative resource options. Due to the timing of the 2023 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2023 DSM program acquisition targets. To ensure that the 2023 IRP analysis is consistent with existing and planned demand response and energy efficiency acquisition levels (i.e., Class 1 & 2 DSM), expected DSM savings in each state were fixed for calendar year 2023. In 2024 and 2025 energy efficiency resources were optimized to reflect ongoing program experience and knowledge of current market conditions and timing challenges, to develop near terms levels of selected acquisition.

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

[9] The 2023 Conservation Potential Study is available on PacifiCorp's demand-side management web page. www.pacificorp.com/energy/integrated-resource-plan/support.html.

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

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

Demand Response: DSM Capacity Supply Curves

The potential and costs for demand response resources were provided at the state level, with impacts specified separately for summer and winter peak periods. Prior to 2023, PacifiCorp has launched and expanded a number of demand response programs to acquire resource needs identified in the 2021 IRP update. Several demand response resources characterized as potential demand response resources in the previous IRP are now considered existing or planned demand response resources which will be effective in 2023.

Table 7.8 – Demand Response Existing and Planned Programs

Product	State	Existing or Planned Offering
Res – HVAC DLC	UT	Existing
Res – Water Heater DLC	OR, WA	Planned
Res – Smart Thermostat	OR, WA	Planned
Res – Grid Interactive Water Heaters	OR, WA	Planned
Res –Battery DLC	ID, UT	Existing
C&I –Battery DLC	ID, UT	Existing
C&I – Third Party	OR, WA, UT	Existing
C&I – Third Party	ID	Planned
Ag – Irrigation DLC	UT, ID, OR, WA	Existing

Table 7.5 and Table 7.6 show the summary level demand response resource supply curve information, by control area. For additional detail on demand response resource assumptions used to develop these supply curves, see Volume 2 of the 2023 CPA.[10] Potential shown is incremental to the existing DSM resources identified in Table 7.5. For existing program offerings, it is assumed that the PacifiCorp could begin acquiring incremental potential in 2023. For resources representing expanded product offerings, it is assumed PacifiCorp could begin acquiring potential in 2024. New program offerings are assumed to be available in 2025 accounting for the time required for program design, regulatory approval, vendor selection, procurement and implementation.

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

Table 7.5 – Demand Response Program Attributes West Control Area[11],*

Product	Summer		Winter	
	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)
Res - EV DLC	46	$381	46	$381
Res – DLC of Smart Home	0.3	$700	1	$354
Res – HVAC DLC	53	$135	94	$73
Res – Pool Pump DLC	0.4	$721	0.1	$1900
Res – Water Heater DLC	35	$139	52	$93
Res – Smart Thermostat	42	$13	38	$15
Res – Grid Interactive Water Heaters	93	$76	135	$52
Battery DLC	4	$33	4	$28
C&I – Third Party	27	$30	42	$35
Ag – Irrigation DLC	24	$23	0	$0

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

Table 7.6 – Demand Response Program Attributes East Control Area[12],*

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
Res - EV DLC	85	$408	85	$408
Res – DLC of Smart Home	1	$814	1	$412
Res – HVAC DLC	119	$49	117	$254
Res – Pool Pump DLC	0.4	$812	0.2	$2141
Res – Water Heater DLC	65	$182	97	$122
Res – Smart Thermostat	73	$19	63	$22
Res – Grid Interactive Water Heaters	5	$131	8	$90
Battery DLC	74	$33	54	$51
C&I – Third Party	43	$40	44	$40
Ag – Irrigation DLC	56	$29	0	$0

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

Energy Efficiency DSM, Energy Supply Curves

The 2023 CPA provided the information to fully assess the potential contribution from DSM energy efficiency resources over the IRP planning horizon. The CPA analysis accounts for known changes in building codes, advancing equipment efficiency standards, market transformation,

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

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

resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g., cost-effectiveness criteria).

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

- **State:** Washington, California, Idaho, Utah, Wyoming[13]
- **Measure:**
  - 110 residential measures
  - 143 commercial measures
  - 96 industrial measures
  - 22 irrigation measures

- **Facility type:**[14]
  - 18 residential facility types
  - 28 commercial facility types
  - 30 industrial facility types
  - Two irrigation facility type

The 2023 CPA levelized total resource costs over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Costs include measure costs and a state-specific adder for program administrative costs for all states except Utah and Idaho. Consistent with regulatory mandates, Utah and Idaho DSM energy efficiency resource costs were levelized using utility costs instead of total resource costs (i.e. incentive and a state specific adder for program administration costs).

The technical potential for all DSM energy efficiency resources across all states except Oregon over the twenty-year CPA planning horizon totaled approximately 16 million MWh.[15] The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (i.e. technical achievable potential). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 13.3 million MWh for all five states. The technical achievable potential for all six states for modeling consideration is 16.8 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures by building type and state generated almost 75,000 separate permutations or distinct measures that

[13] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.
[14] Facility type includes such attributes as existing or new construction, single or multi-family, and income level for the residential sector. Facility types represent a combination of market segment and vintage and are more fully described in in the Analysis Approach in Volume 1, of the 2023 CPA.
[15] The identified technical potential represents the cumulative impact of DSM measure installations in the 20th year of the study period for California, Idaho, Washington, Wyoming, and Utah. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period. ETO provides PacifiCorp with technical achievable potential.

could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs and net cost of capacity to reduce the number of combinations to a more manageable number.

Bundle development began with the energy efficiency technical potential identified by the 2021 CPA. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 20-year planning horizon. Consistent with the Northwest Power and Conservation Council's achievability assumptions in the 2021 Power Plan as, which typically assume that 85% of the technical potential could be acquired over the 20-year period.[16]

For Oregon, the company does not assess potential for the Energy Trust of Oregon (ETO). Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the DSM energy efficiency supply curves used in the development of the 2023 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp's six states.

Twenty-seven cost bundles, with a separate bundle reserved for home energy reports, were available across six states (including Oregon), which equates to 162 DSM energy efficiency resource supply curves. Table 7.7 shows the 20-year MWh potential for DSM energy efficiency net cost of capacity bundle categorization.

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

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

Table 7.7 – 2042 Total Cumulative Energy Efficiency Potential by Cost Bundle Category (MWh)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
Cooling Measures	27,058	89,984	435,590	2,191,500	138,834	203,854
Heating Measures	24,393	119,582	697,503	1,063,751	162,002	79,231
Summer Measures	11,928	20,354	0	448	5,112	1,559
Winter Measures	59,371	65,660	579,073	842,274	285,520	348,928
Zero Cost Temperature Dependent Measures	11,186	58,479	353,995	1,167,754	76,941	95,802
Zero Cost Non-Temperature Dependent Measures	35,105	338,878	1,303,580	4,581,945	455,591	823,909

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

- A state-specific transmission and distribution investment deferral cost credit (Table 7.8)
- Stochastic risk reduction credit of $2.25/MWh[17]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[18]

Table 7.8 – State-specific Transmission and Distribution Credits

State	Transmission Deferral Value ($/KW-year)	Distribution Deferral Value ($/KW-year)	Total
California	$5.09	$8.38	$13.47
Oregon	$5.09	$10.46	$15.55
Washington	$5.09	$10.69	$15.78
Idaho	$5.09	$12.57	$17.66
Utah	$5.09	$12.90	$17.99
Wyoming	$5.09	$5.76	$10.85

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

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

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

each bundle uses an annual 8,760 hourly load shape specifying the portion of the maximum capacity available in any hour of the year. These shapes are created by spreading measure-level annual energy savings over 8,760 load shapes, differentiated by state, sector, market segment, and end use accounting for the hourly variance of energy efficiency impacts by measure. These hourly impacts are then aggregated for all measures in each bundle to create a single weighted average load shape for that bundle.

Distribution Efficiency

PacifiCorp continues to develop its CYME CYMDIST® (power flow software) investment in ways that improve engineering response time and, indirectly, distribution system efficiency. In the last biennial period, more than 300 large (Level 2 and Level 3) distributed energy resource (DER) applications were studied in CYME. This resulted in more than 29 MW (nameplate) of approved private generation across the company. Any energy savings resulting from these approvals across the service territory has not been determined.

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

Transmission Resources

In developing resource portfolios for the 2023 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Market Purchases

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

FOTs are proxy resources representing a range of purchase transaction types. They can be standard products, such as heavy load hour (HLH), light load hour (LLH), and super peak, but may be non-standard products provided the arrangements are considered firm. FOTs typically rely on standard enabling agreements as a contracting vehicle. FOT prices are determined at the time of the transaction, usually via an exchange or third-party broker, and are based on the then-current forward market price for power. An optimal mix of these purchases would include a range of volumes and terms for these transactions.

As described in Volume I, Chapter 5 (Reliability and Resiliency), solicitations for FOTs can be made years, quarters or months in advance, however, are generally committed to balance PacifiCorp's system on a balance of month, day-ahead, hour-ahead, or intra-hour basis. The terms, points of delivery, and products vary by individual market point. For FOT purchase limits, please refer to Volume I, Chapter 5 (Reliability and Resiliency), Table 5.8 – Maximum Available Front Office Transactions by Market Hub.

Additional discussion of how FOTs are modeled during the resource portfolio development process of the IRP is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

CHAPTER 8 – MODELING AND PORTFOLIO EVALUATION

CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios.
- PacifiCorp used Plexos software to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and number of new resources that could be pursued to serve customers over the next 20 years.
- The Plexos Long-Term (LT model) was used to generate initial portfolios and identify the resulting fixed costs. PacifiCorp used the Plexos Medium-Term schedule (MT model) to perform stochastic risk analysis of the portfolios. Each initial portfolio was evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three carbon dioxide (CO_2) price scenarios (zero, medium, high). An additional CO_2 policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gases (SC-GHG). Taken together, there are five distinct price-policy scenarios (medium gas/medium CO_2, medium gas/zero CO_2, high gas/high CO_2, low gas/zero CO_2, and the social cost of greenhouse gases).
- A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.
- Each initial portfolio was also evaluated in the Short-Term model (ST model) to establish system costs over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement (PVRR) which serves as the basis for selecting least-cost least-risk portfolios.
- The MT model risk-adjustment was added to the system cost determined by the ST model to calculate a final "risk-adjusted" PVRR measure of system cost. All three models in the Plexos suite, the LT, MT and ST, were thus used to arrive at final reliable portfolio for comparative analysis.
- A selection of competitive "variant" portfolios was analyzed using the other four price-policy scenarios in the ST and MT models to evaluate how each portfolio performs under differing market/policy conditions.
- Taking into consideration stakeholder comments and regulatory requirements, PacifiCorp produced additional studies that examine the potential impact of portfolio options on the system.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from the ST and MT models, comparing resource portfolios based on expected costs, low-probability high-cost outcomes, reliability, CO_2 emissions and other criteria.

Introduction

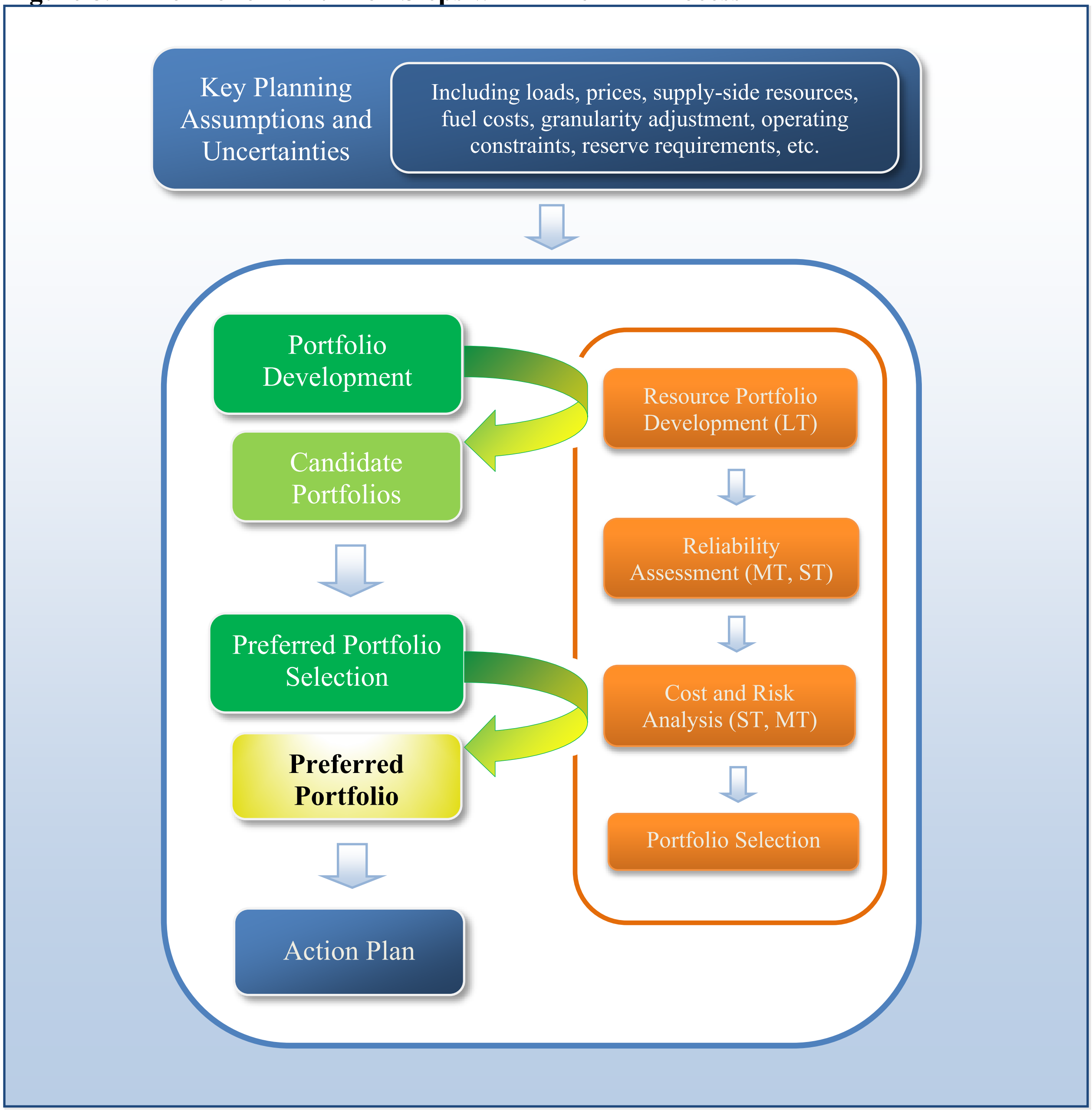
IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting reliability requirements. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

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

Modeling and Evaluation Steps

Figure 8.1 summarizes the modeling and evaluation steps for the 2021 IRP, highlighted in green. The highest-level steps are (1) portfolio development, and (2) portfolio screening. The result of the final screening step is selection of the preferred portfolio.

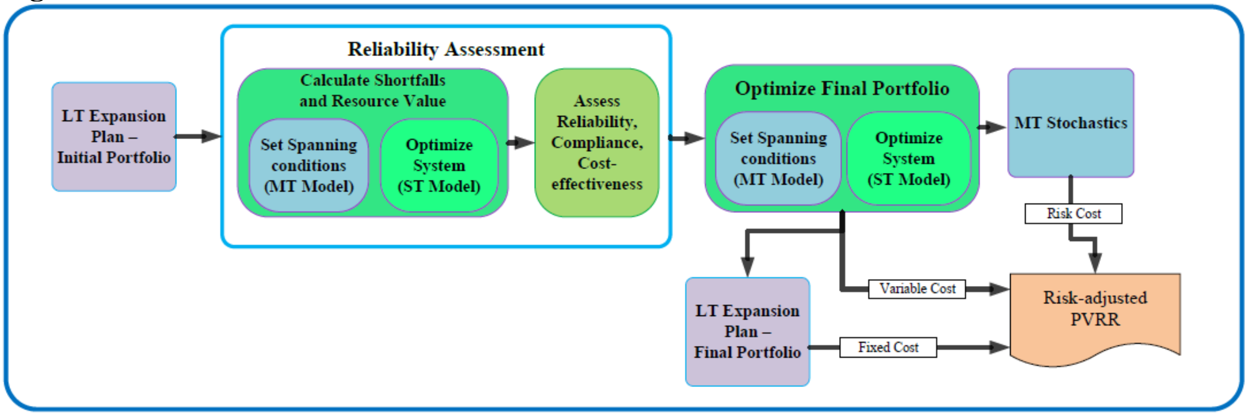
Figure 8.1 – Portfolio Evaluation Steps within the IRP Process



For each modeling and evaluation step, PacifiCorp developed unique resource portfolios, analyzed deterministic cost and stochastic risk metrics for each portfolio, and selected, based on comparative cost and risk metrics, the specific portfolios considered in the next modeling and evaluation step. The outcomes of each can inform the need for additional studies to test or refine assumptions in a subsequent screening analysis.

Figure 8.2 provides additional process detail regarding these portfolio processing elements, followed by descriptions of each element.

Figure 8.2 – Portfolio Production Process



Resource Portfolio Development

All IRP models are configured and loaded with the best available information at the time a model run is produced. This information is fed into the LT model, which is used to produce resource portfolios with sufficient capacity to be reliable on a 20-year aggregated granularity basis.

Reliability Assessment

Resource portfolios developed by the LT model are simulated in the ST model to quantify reliability shortfalls at an hourly level. The ST model also supports the assessment of each resource's net system value, inclusive of resources that are not part of the specific portfolio being examined. This allows for the refinement of each portfolio according to a highly granular view of its needs and at the same time provides the data necessary to incorporate portfolio modifications needed to optimally ensure reliability, regulatory compliance and cost-effectiveness. The adjusted portfolio is then rerun through the ST model to create an optimal dispatch which considers all resource availability and system requirements at an hourly level, inclusive of individual resource operations and market purchases.

Cost and Risk Analysis

Resource portfolios developed by the LT model and adjusted for reliability, compliance and cost-effectiveness by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed using Monte Carlo sampling of stochastic variables across the 20-year study horizon, which include load, natural gas and wholesale electricity prices, hydro generation, and unplanned thermal outages. The MT results are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR to guide portfolio selection.

Portfolio Selection

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

Resource Portfolio Development

Resource expansion plan modeling, performed with the LT model, is used to produce resource portfolios with sufficient capacity to achieve reliability over the 20-year study horizon by evaluating groups of hours on an aggregated basis. Each resource portfolio is refined for reliability at an hourly granularity during the reliability assessment development step. Each portfolio is uniquely characterized by the type, timing, location, and number of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks. New to this IRP is using the LT model to consider the retirement of both coal and gas resources endogenously in any year.

Long-Term (LT) Capacity Expansion Model

In the 2023 IRP, the LT model is used to establish an initial portfolio under expected conditions (medium gas, medium CO_2), and then modified for each case, based on study parameters, to eliminate shortfalls and maintain reliability. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints.[1] Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves plus a minimum planning reserve margin (PRM)[2] for each load area represented in the model.

The initial resource portfolio developed with the LT model is appropriately reliable to its granularity and performance limitations. Operating reserve requirements include contingency reserves, which are calculated as 3% of load and 3% of generation. The planning reserve margin in the 2023 IRP is set at a "floor" of 13% at each load area in the topology, as provided in Figure 8.3.

If an early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirement in each period and location. The LT model may also select additional resources that are more economic than an existing generating resource. In the 2023 IRP, the model is simultaneously considering resource additions for reliable and economic system operation both

[1] LT model performance limits the granularity at which the model can be run. For the 2023 IRP there is an additional reliability assessment performed in the ST model to ensure that final portfolios meet reliability requirements.

[2] The Plexos model uses 'capacity reserve margin' for what PacifiCorp has traditionally described as 'planning reserve margin' ("PRM"). While capacity reserve margin is slightly more precise, PRM is used in the 2023 IRP to reduce confusion over the use of multiple similar terms and because PRM is the industry standard term.

before and after existing generation resources retire, as well as which years to retire those existing resources in.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. To enhance the ability of the LT model to differentiate key resource types and system conditions, for the 2023 IRP, each month was split into seven blocks of hours based on load, wind, and solar, derived from PacifiCorp's 2021 IRP Update :

1. The single highest net load hour for the system (load net of wind and solar)
2. The single highest net load hour for the east balancing area
3. The single highest net load hour for the west balancing area
4. The top ten percent highest net load hours, excluding the above. 10% is approximately 70 hours per month, or an average of 2-3 per day, though some days may not have any hours in this group at all.
5. The top ten percent highest wind generation hours on a system basis.
6. The top ten percent highest solar generation hours on a system basis.
7. All other hours

The result of this modeling is to indicate to the LT model that wind and solar have very high availability in some hours, and very low availability in others. This would be expected to contribute to more moderate selections of wind and solar, as they will saturate some periods and have lower value. It would also be expected to contribute to selections of storage and peaking resources, targeted to cover periods in which wind and solar provide little generation supply.

Plexos LT model dispatch among blocks of hours in a month is not chronological, so it cannot constrain energy storage charging and discharging, except to ensure that over the course of a month these remain balanced. But within that limitation, Plexos determines generation and storage dispatch, optimal electricity flows between zones, and optimal market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Key modeling elements and inputs for the LT capacity expansion model include the following:

Transmission System

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

Figure 8.3 – Transmission System Model Topology with Options

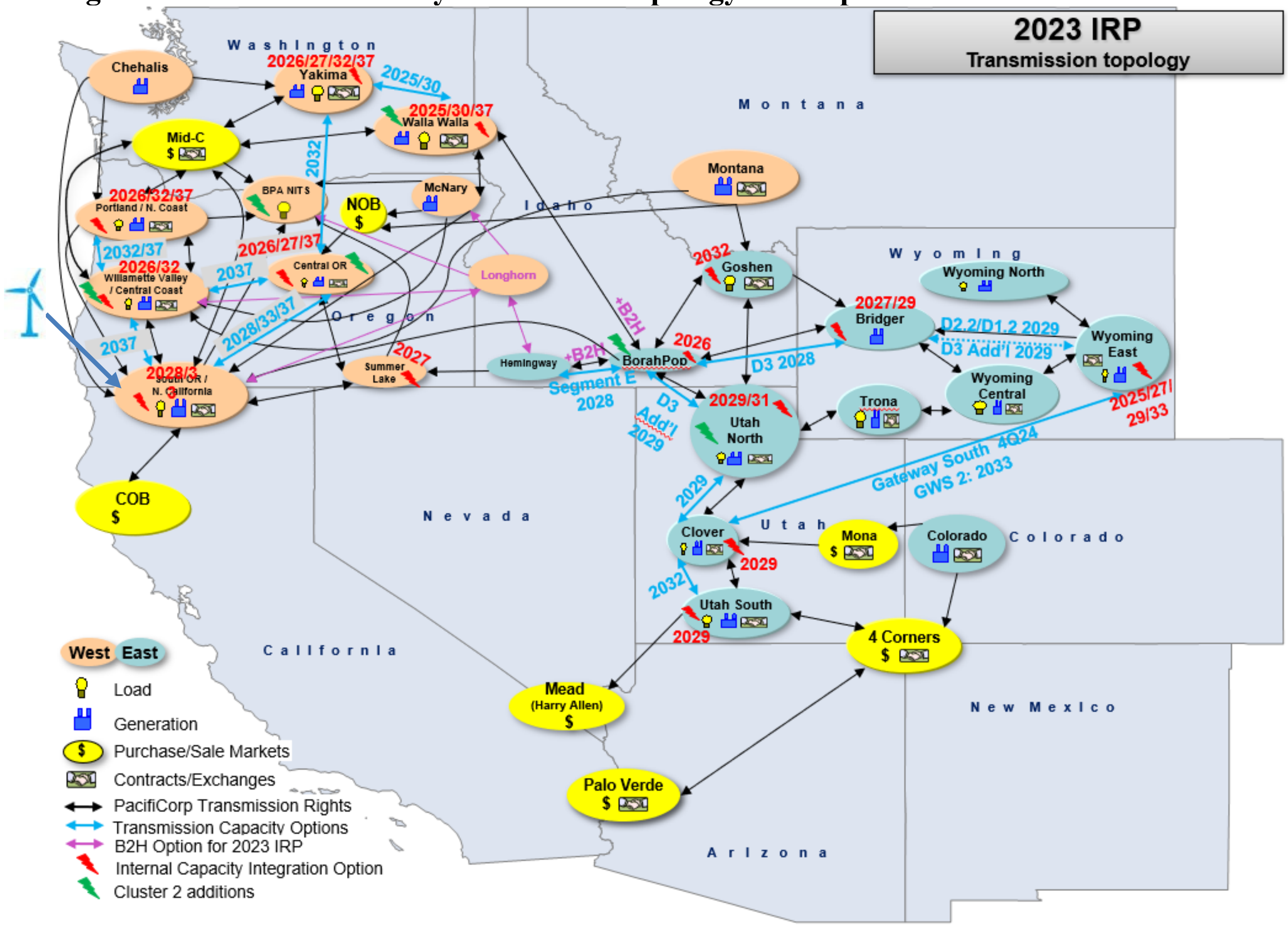


Figure 8.3 illustrates the 2023 IRP modeled topology where each transmission area or "bubble" is defined by any load and generation capability, it's location on the system and its connections to other bubbles.

Transmission Options

In addition to topology, Figure 8.3 illustrates modeled options for endogenous selection by the LT model. Over a span of three public input meeting, PacifiCorp presented information about transmission modeling as it was developed and presented interconnection and Cluster study results used to establish resource and transmission options based on the best available data.

"Interconnection" requires modifications, additions, or upgrades to physically and electrically connect a generating facility to the transmission system. Which requirements apply can be impacted by the generation facility type, detailed project specifications, location, prior/existing generation facilities and load.

Studies needed to identify interconnection requirements are interdependent and extensive. Interconnection is carefully regulated for the safety, reliability, and efficiency of the electrical grid. Requests for interconnection made by any project are regulated and managed in various ways, such as:

- **Serial queue:** Signed agreements and near-final serial queue requests.

- **Transition Cluster:** Remaining serial queue requests and 2020 requests.
- **Cluster Study 1:** Spring 2021 requests.
- **Cluster Study 2:** Spring 2022 requests.
- **Colstrip:** Interconnection to jointly-owned Colstrip transmission assets.
- **Surplus:** Interconnection of additional resources at the same point as an existing generator, with aggregate output not exceeding the existing limit.
- **Provisional:** Interconnection study identifies maximum permissible output before transmission upgrades that are not yet in service.
- **Oregon Community Solar:** projects under 3MW seeking to participate in the Oregon Community Solar program.
- ***Informational Studies*:** Informational only, proposal and results are not considered part of later interconnection requests and cannot lead to an interconnection agreement.

The process of evaluating the viability of future projects is complex and time-consuming, resulting in many pending interconnection requests. In 2020, PacifiCorp transitioned from a serial queue study process (one generator at a time) to an annual cluster study process (one study for all new requests in a given area). In the 2023 IRP PacifiCorp significantly enhanced its study of resource and transmission potential to better align with project expectations and costs resulting from these advanced studies. Cluster studies are described further in Chapter 4 – Transmission.

<u>Surplus Interconnections</u>

Surplus interconnections add more generation to an existing interconnection without requiring additional transmission lines. However, while installed nameplate capacity is increased at a site, the total megawatt output at any given time and location cannot exceed the original interconnection capacity. Considering the proliferation of variable resources which do not always occupy the entirety of a given transmission line, the 2023 IRP added surplus resource capability to its capacity expansion modeling options.

Added generation can be of the same type and can take the form of additional generating unit or increased generation capability, such as wind repowering resulting in higher nameplate capacity than the existing interconnection. In the event an added resource is of a different type, a hybrid is created. For example, a hybrid resource combination of solar, wind and storage allow a higher net capacity factor among all three resources, increasing overall generation, while avoiding the need for added transmission.

PacifiCorp has submitted surplus interconnection requests to evaluate the addition of solar to several wind resource sites in Wyoming.

Transmission Costs

In developing resource portfolios for the 2023 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and number of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.

Resource Adequacy

In its 2023 IRP, PacifiCorp used a 13% hourly planning reserve margin requirement for each topology location containing load in the LT model. The planning reserve margin applies in all periods and must be met by available resources within that area or imports from adjacent areas with excess resources available, subject to transmission constraints. This treatment is an improvement on a traditional planning reserve margin which accounts only for peak load capacity met by an estimated firm capacity contribution. Additionally, the 2023 IRP directly modeled operating reserve requirements in expansion plan model runs, which ensures that expansion resources selected to PRM requirements will also meet operating contingency spin and non-spin reserve requirements. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

Granularity and Reliability Adjustments

As detailed during the 2023 IRP public-input process, the granularity adjustment reflects the difference in economic value between an hourly 8760 cost calculation in ST modeling, and the seven-block per month representation used in the LT model.

This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the block granularity smooths out many of the storage arbitrage opportunities and also doesn’t fully capture the effect of storage duration limits.

In parallel with the granularity adjustment, the reliability adjustment addresses unmet capacity needs by hour in the LT model portfolio selection. Much of the peak load hour requirements in mid-afternoon in the summer are adequately met by solar resources. However, resource requirements are driven by portfolio-dependent *net* load peaks (load less renewable resource output), which are harder for the LT model to identify.

While the granularity and reliability adjustments help direct the LT model to more cost-effective resources and a more reliable portfolio, the LT model cannot guarantee reliability at an hourly operational level. Marginal benefits decline as any resource type becomes a larger share of a portfolio, as it saturates the need in the hours it is available. A similar effect occurs with storage, where each incremental MW of system storage capacity must cover a longer duration.

Because of the performance limitations of capacity expansion optimization, the ST model is leveraged to refine the portfolio to achieve a final balanced and reliable mix of resources, as described under the Cost and Risk Analysis section of this analysis, further below.

Thermal Resource Options

Modeling in the 2023 IRP greatly expanded the range of endogenous selections available for optimization. In the 2019 IRP, 78 specific portfolio strategies were examined for the potential retirement of coal generating facilities. Upon moving to the Plexos model for the 2021 IRP this range of modeled possibilities expanded to more than 260,000 possible coal retirement configurations. In the 2021 RP cycle, for owned/operated coal units, potential retirement dates were based upon avoiding major overhauls, assuming a unit would be able to operate five years after an overhaul. In the 2023 IRP the possible combinations of outcomes available for endogenous selection in the LT model number in the trillions. This includes possibilities for conversion of coal units to burn natural gas, installation of carbon capture technology, selective catalytic reduction, selective non-catalytic reduction, and the capability to optimize natural gas generator retirements, new functionality in this IRP.[3]

In addition, for the 2023 IRP, all majority-owned and operated coal plant sites are considered candidates for surplus interconnection, such that other technologies can be added prior to the coal plant's retirement, with the aggregate of the existing and surplus resource output limited to the current maximum output of the coal resource. As a result, the LT model simultaneously evaluates the value of surplus resources both before and after the associated coal units retire, while at the same time evaluating when they should retire.

Table 8.1 reports the coal unit options modeled in the 2023 IRP, whereas Table 8.2 summarizes the options available for natural gas-fired units.

[3] Minority-owned coal units Colstrip 3 & 4 are subject to discussion with joint-owners; Craig and Hayden have agreed-upon retirement dates. Environmental compliance requirements were incorporated, including but not limited to Regional Haze, the Ozone Transport Rule, and carbon capture technology

Table 8.1 - Coal Generator Resource Options

Jim Bridger Units 1 and 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas/Alt. Fuel-2024		Gas														Retired				
Jim Bridger Units 3 and 4	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2037																Retired				
Gas/Alt. Fuel-2026				Gas												Retired				
Coal-CCUS 2028						CCUS												Retired		
Naughton Units 1 and 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2025				Retired																
Gas-2026				Gas											Retired					
Dave Johnston 1 and 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2032							Retired													
Dave Johnston 3	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2027						Retired														
Dave Johnston 4	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2039																		Retired		
Gas-2027					Gas													Retired		
Coal CCUS+SCR 2028						CCUS+SCR												Retired		
Wyodak	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2039																		Retired		
Gas-2027					Gas													Retired		
Coal SCR-2026				SCR														Retired		
Coal SNCR-2026				SNCR														Retired		
Dual Fuel-2027					Duel Fuel													Retired		
Hunter 1	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2042																				
Coal SCR-2026				SCR																
Coal SNCR-2026				SNCR																
Hunter 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2042																				
Coal SCR-2026				SCR																
Coal SNCR-2026				SNCR																
Hunter 3	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2042																				
Coal SCR-2026				SCR																
Coal SNCR-2026				SNCR																
Huntington 1	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2036															Retired					
Coal SCR-2026				SCR											Retired					
Coal SNCR-2026				SNCR											Retired					
Huntington 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Coal Ret-2024 thru 2036															Retired					
Coal SCR-2026				SCR											Retired					
Coal SNCR-2026				SNCR											Retired					

Key
- Default/current operation
- Retirement option
- Gas conversion option
- Emissions technology option; SCR, SNCR, CCUS
- Assumed retired

Table 8.2 - Natural Gas Generator Resource Options

Chehalis	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2042																				
Currant Creek	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2042																				
Hermiston 1/2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2036															Retired					
Lakeside 1	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2042																				
Turbine Upgrade			Upgraded																	
Wet Compression																				
Lakeside 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2042																				
Turbine Upgrade			Upgraded																	
Wet Compression																				
Naughton Unit 3	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2036															Retired					
Gadsby 1	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									
Gadsby 2	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									
Gadsby 3	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									
Gadsby 4	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									
Gadsby 5	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									
Gadsby 6	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Gas Ret-2026 thru 2032											Retired									

Key
- Default/current operation
- Retirement option
- Assumed retired
- Turbine upgrade
- Wet compression

New Resource Options

<u>Demand-Side Management</u>

Energy efficiency resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand response resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

<u>Wind and Solar Resources</u>

Proxy wind and solar resources available for inclusion in the preferred portfolio are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources represent expected monthly generation levels such that half of the time actual monthly generation would fall below expected levels, and half of the time actual monthly generation would be above expected levels assuming no curtailments. Where

The ability for wind and solar resources, to reliably meet demand over time is impacted by the forecasted profiles, along with mix of other resources in the portfolio. The use of resource availability to meet requirements in all periods allows the model to endogenously account for declining capacity contribution due to the increasing penetration of resources with similar dispatch patterns.

Non-Emitting Resources

Two non-CO_2-emitting thermal resources are considered: advanced nuclear projects and non-emitting peaking units. Advanced nuclear resources are characterized by continuous operation and substantial storage in the form of heat stored as molten salt. In contrast, non-emitting peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls. The non-emitting peaking resource is assumed to use a non-CO_2 emitting fuel such as hydrogen.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

- Energy take – generation or extraction of energy from a storage reservoir for a specified period;
- Energy return – energy used to fill (or charge) a storage reservoir; and
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and variable costs, if applicable.

Market Purchases

Market purchases are transactions by the company's front office and represent short-term firm agreements for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., future months or quarters, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or the exchange provides a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all of the short-term firm physical power products, differing by delivery pattern and delivery period, which are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the contribution of short-term firm market purchases is accounted for in the portfolio-development process. For capacity expansion optimization modeling, market purchases contribute capacity toward meeting the 2023 IRP's planning reserve margin and supply energy to meet system needs.

Capital Costs

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. All capital costs evaluated in the IRP are converted to nominal levelized revenue requirement costs. Use of nominal levelized revenue requirement costs is an established methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the nominal levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes and income taxes over the life of the investment. The result is an annuity or annual payment that remains constant such that the PVRR is identical to the PVRR of the nominal requirement when using the same nominal discount rate.

General Assumptions

<u>Study Period and Date Conventions</u>

PacifiCorp executes its 2023 IRP models for a 20-year period beginning January 1, 2023 and ending December 31, 2042. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, except for coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period after ceasing coal-fired operation at the end of the prior year.

<u>Inflation Rates</u>

The 2023 IRP simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.27 percent is assumed. This escalation rate reflects the average of annual inflation rate projections for the period 2023 through 2042, using PacifiCorp's September 2022 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the Consumer Price Index.

<u>Discount Factor</u>

The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2023 IRP is 6.77 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[4] PVRR figures reported in the 2023 IRP are reported in 2022 dollars.

[4] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

CO_2 Price Scenarios

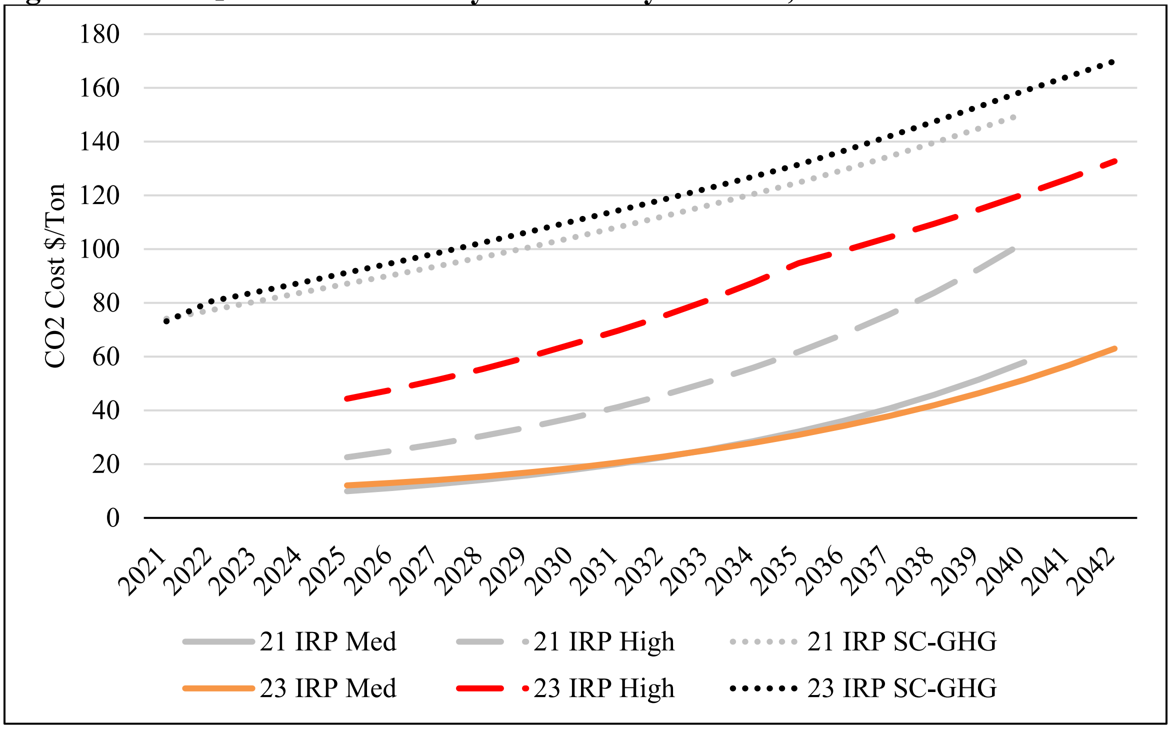
PacifiCorp used four different CO_2 price scenarios in the 2023 IRP—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The medium and high scenario are derived from a variety of sources, including government and electric utility forecasts, and expert third-party multi-client "off-the-shelf" subscription services. PacifiCorp grouped these forecasts around the median low and median high forecast. The highest grouping, consisting of six different forecasts, was averaged to form the high price case. The lowest grouping, also consisting of six different forecasts, was averaged to form the medium case. These scenarios apply a CO_2 price as a tax beginning 2025.

PacifiCorp also incorporated the social cost of greenhouse gas in compliance with Washington RCW 19.280.030. The 2023 IRP includes an adjusted cost of greenhouse gas emission reflecting inflation, defined by the Washington Utilities and Transportation Commission.[5] The social cost of greenhouse gas emissions is assumed to apply in all years of the study horizon. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

In all scenarios, emissions from the Chehalis natural gas plant incur the forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by the Washington Legislature in 2021. This is in addition to the assumed federal CO_2 policy represented in the zero, medium, high, and social cost of greenhouse gas scenarios described above. The modeled allowance cost reflects analysis conducted by Vivid Economics for the Washington Department of Ecology and starts at \$58/ton in 2023.[6]

[5] Washington Utilities and Transportation Commission, Order 03, Docket No. U-190730, July 28, 2022.
[6] Summary of market modeling and analysis of the proposed Cap and Invest Program. June 2022. Available online at: https://ecology.wa.gov/DOE/files/4a/4ab74e30-d365-40f5-9e8f-528caa8610dc.pdf (Accessed 3/21/2023)

Figure 8.4 – CO_2 Prices Modeled by Price-Policy Scenario, 2021 and 2023 IRP



<u>Wholesale Electricity and Natural Gas Forward Prices</u>

For 2023 IRP modeling purposes, five electricity price forecasts were used: the official forward price curve (OFPC) and four scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

At the time PacifiCorp's 2023 IRP modeling inputs were prepared, the September 2022 OFPC was the most current OFPC available. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflects market forwards at the close of a given trading day.[7] As such, these 36 months are market forwards as of September 2022. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas OFPC reflects an expert third-party multi-client "off-the-shelf" price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAxmp[8] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

[7] The March 2021 OFPC prompt month is May 2021; April 2021 would be traded as "balance of month" when the OFPC is released.

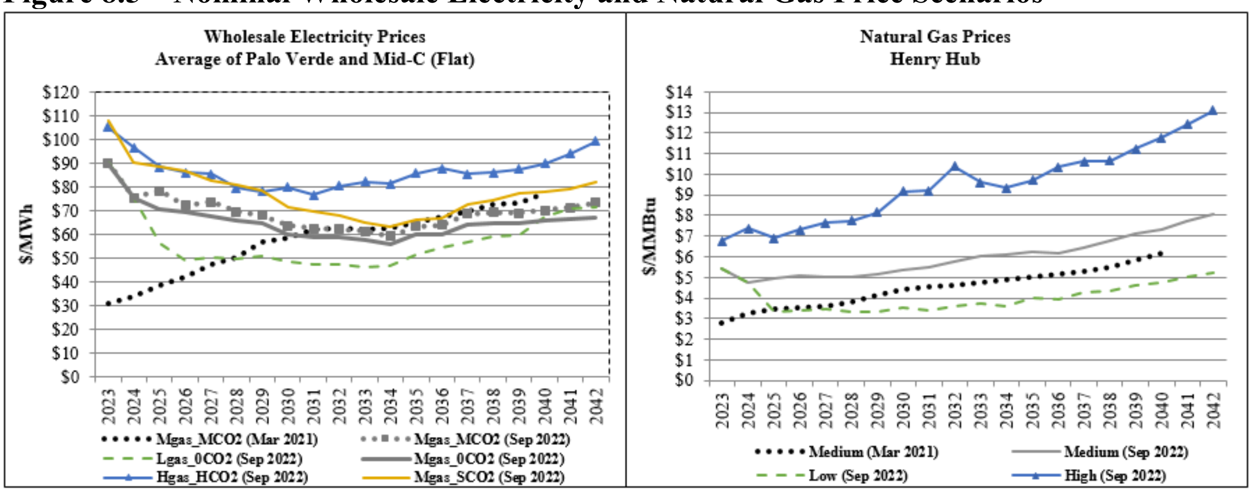
[8] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2026 before transitioning to a pure-fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party multi-client "off-the-shelf" subscription services.

PacifiCorp's OFPC for electricity and each of its five scenarios were developed from one of three (medium, low, high) underlying expert third-party natural gas price forecasts in conjunction with one of four CO_2 price scenarios.[9] The OFPC used in the 2023 IRP does not assume any CO_2 policy or tax in conjunction with its medium gas price forecast. However, PacifiCorp's 2021 IRP "medium case" price forecast is not the OFPC but a scenario that couples medium gas with a medium CO_2 price, applied for forecasting purposes as a tax. Thus, the 2023 IRP medium case differs from that of the September 2022 OFPC by assuming a medium CO_2 price starting in 2025. This medium CO_2 price serves as a proxy for a potential future CO_2 policy.

Figure 8.5 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2023 IRP.

Figure 8.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Cost and Risk Analysis

Short-Term (ST) Schedule Model

The ST model uses the same common input assumptions described for the LT model with additional data provided by two other Plexos models. The LT model results provide the initial capacity expansion plan, and the MT model provides an optimized set of spanning conditions.

[9] Zero CO_2, medium CO_2 price, high CO_2 price, and a society-based cost of CO_2.

Spanning conditions are constraints that must be observed across periods of time that extend beyond the ST model's ability to "see" as it chronologically optimizes several days of hourly data at a time (e.g., an annual emissions limit). The MT model can determine for each month how each spanning condition is allocated for the ST model's use. The result is that even though the ST model is focused on hourly details and cannot simultaneously account for limitations that span across every hour in a year, the model will nonetheless appropriately adhere to an annual constraint.

Reliability Assessment and System Cost

The ST model begins with a portfolio from the LT model that has not yet been refined to reflect the reliability and compliance needs of a particular study (e.g., a particular sensitivity or price-policy scenario). The ST model is first run at an hourly level for 20 years in order to retrieve two critical pieces of data: 1) shortfalls by hour, and 2) the value of every potential resource to the system that is specific to the portfolio itself, and other input assumptions, such as the price-policy scenario.

This information is used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR which is risk-adjust by outcomes of MT model stochastics.

Resource Value

Plexos calculates a locational marginal price (LMP) specific to each area in each hour that is based on supply and demand in that area and available imports and exports on transmission links to adjacent areas. This is also known as a shadow price. Plexos also calculates the marginal price specific to ancillary services (i.e., operating reserves) in each hour. Plexos then multiplies these prices by a resource's optimized energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. In an organized market, this would represent the expected payments based on market-clearing prices.

When variable costs (such as fuel, emissions, and VOM) are subtracted out, the result is a resource's "net revenue". Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, modeling capabilities, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated, and marginal prices will again reflect the variable cost of an available resource.

Portfolio Refinements

While many resource options are evaluated, new generation resources are mostly restricted to two circumstances: surplus or replacement resources at generators that are eligible to retire, and new resources at locations with interconnection or transmission upgrade options.

These interconnection and transmission upgrade options are limited and can be expensive. Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in "firm" capacity creates a need for additional interconnection capacity elsewhere, and a key strategy is maximizing the "firmness" of each MW of interconnection capacity to provide greater value. For this reason, in the 2023 IRP, the modeling of replacement and expansion resources was not limited by the nameplate of resources being added, but rather to by an hourly maximum generation constraint. As such, the model is able to select any combination of resources leading to a smoothing of hourly capacity among various renewable or peaking/firm resources. Batteries are assumed to always be co-located with other resources, enabling them to shift energy accumulated during periods of high solar radiance, wind speed or other generation, and increase the effective capacity contribution of the combination of resources in a given location.

Portfolio Cost

The second run of the ST model produces an optimized dispatch of the reliability-adjusted portfolio to reflect least-cost operations while meeting all requirements and adhering to modeled constraints. The ST model's hourly granularity means that this system cost will be highly accurate, taking into account operational nuances that are obscured in the less granular LT and MT models. This in turn means that when evaluating the constellation of all competitive portfolios, the comparison will be based on appropriate relationships among all system components to yield an accurate PVRR.

Additional Measures

- Annual and energy not served (ENS)
- Annual CO_2 emissions.

Medium-Term (MT) Schedule Model

The MT model uses the same common input assumptions described for LT and ST models with additional data provided by the LT and ST model results (e.g., the capacity expansion portfolio). While the LT and ST models supply an optimized portfolio for each case, the MT model can bring the advantages of stochastic-driven risk metrics to the evaluation of the studies. While deterministic ST system cost results are the most precise available due the hourly granularity, the MT model provides the necessary data to calculate a stochastic risk metric for each case, which is then added to the ST system cost outcomes to produce the risk adjusted PVRR for each case.

Cost and Risk Analysis

Once unique resource portfolios are developed using the LT and ST models, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed with the MT model.

The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.

The stochastic parameters used in the MT model for the 2023 IRP are developed with a short-run mean reverting process, whereby mean reversion represents a rate at which a disturbed variable returns to its expected value. Stochastic variables may have log-normal or normal distribution as appropriate. The log-normal distribution is often used to describe prices because such distribution is bounded on the low end by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average. Unlike prices, load generally does not have such skewed distribution and is generally better described by a normal distribution. Volatility and mean reversion parameters are used for modeling the volatilities of the variables, while accounting for seasonal effects. Correlation measures how much the random variables tend to move together.

Stochastic Model Parameter Estimation

Stochastic parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. Loads and commodity prices are mean-reverting in the short term. For instance, natural gas prices are expected to hover around a moving average within a given month and loads are expected to hover near seasonal norms. These built-in responses are the essence of mean reversion. The mean reversion rate tells how fast a forecast will revert to its expected mean following a shock. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. The stochastic parameters are used to drive the stochastic processes of the following variables:

- Representative natural gas prices for PacifiCorp's east and west balancing authority areas;
- Electricity market prices for Mid-C, COB, Four Corners, and Palo Verde;
- Loads for California, Idaho, Oregon, Utah, Washington, and Wyoming regions; and
- Hydro generation.

Volume II, Appendix H (Stochastic Parameters) discusses the methodology for developing the stochastic parameters for the 2023 IRP.

For unplanned thermal outages, PacifiCorp assumes a uniform distribution around an expected rate. For existing units, the expected unplanned outage rates by unit are based on its historical performance. For new resources, the unplanned outage rates are as specified for those resources as listed in the supply-side resource table in Volume I, Chapter 7 (Resource Options). Table 8.3 through Table 8.10 summarize updated stochastic parameters and seasonal price correlations for the 2023 IRP.

Table 8.3 – Short-Term Load Stochastic Parameters

Short-Term Volatility	CA/OR without Portland	Portland	ID	UT	WA	WY
Winter 2023 IRP	0.044	0.041	0.038	0.024	0.050	0.021
Spring 2023 IRP	0.036	0.035	0.064	0.035	0.042	0.021
Summer 2023 IRP	0.045	0.060	0.061	0.054	0.054	0.021
Fall 2023 IRP	0.042	0.036	0.047	0.035	0.044	0.020
Short-Term Mean Reversion	**CA/OR without Portland**	**Portland**	**ID**	**UT**	**WA**	**WY**
Winter 2023 IRP	0.261	0.252	0.263	0.380	0.171	0.279
Spring 2023 IRP	0.236	0.229	0.146	0.332	0.164	0.109
Summer 2023 IRP	0.169	0.183	0.143	0.265	0.173	0.190
Fall 2023 IRP	0.251	0.365	0.128	0.234	0.213	0.224

Table 8.4 – Short-Term Gas Price Parameters

Short-Term Volatility	East Gas	West Gas
Winter 2023 IRP	0.272	0.237
Spring 2023 IRP	0.134	0.224
Summer 2023 IRP	0.135	0.148
Fall 2023 IRP	0.153	0.743
Short-Term Mean Reversion	**East Gas**	**West Gas**
Winter 2023 IRP	0.129	0.074
Spring 2023 IRP	0.304	0.155
Summer 2023 IRP	0.525	0.405
Fall 2023 IRP	0.244	0.570

Table 8.5 – Short-Term Electricity Price Parameters

Short-Term Volatility	Four Corners	COB	Mid-Columbia	Palo Verde
Winter 2023 IRP	0.194	0.191	0.223	0.174
Spring 2023 IRP	0.193	0.238	0.564	0.164
Summer 2023 IRP	0.311	0.946	0.392	0.288
Fall 2023 IRP	0.215	0.189	0.190	0.206
Short-Term Mean Reversion	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**
Winter 2023 IRP	0.103	0.101	0.101	0.102
Spring 2023 IRP	0.216	0.213	0.477	0.199
Summer 2023 IRP	0.213	1.014	0.300	0.149
Fall 2023 IRP	0.238	0.297	0.294	0.230

Table 8.6 – Winter Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.399	1.000				
COB	0.295	0.577	1.000			
Mid - Columbia	0.337	0.522	0.725	1.000		
Palo Verde	0.451	0.886	0.575	0.558	1.000	
Natural Gas West	0.688	0.203	0.262	0.292	0.244	1.000

Table 8.7 – Spring Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.157	1.000				
COB	0.134	0.384	1.000			
Mid - Columbia	0.139	0.406	0.584	1.000		
Palo Verde	0.133	0.718	0.282	0.275	1.000	
Natural Gas West	0.618	0.150	0.189	0.143	0.084	1.000

Table 8.8 – Summer Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.130	1.000				
COB	0.110	0.219	1.000			
Mid - Columbia	0.234	0.400	0.608	1.000		
Palo Verde	0.127	0.785	0.295	0.472	1.000	
Natural Gas West	0.810	0.110	0.065	0.207	0.068	1.000

Table 8.9 – Fall Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.047	1.000				
COB	0.131	0.296	1.000			
Mid - Columbia	0.122	0.257	0.708	1.000		
Palo Verde	0.034	0.768	0.372	0.335	1.000	
Natural Gas West	0.199	-0.008	-0.087	-0.033	0.030	1.000

Table 8.10 – Hydro Short-Term Stochastic

	Short-Term Volatility	Short-Term Mean Reversion
Winter 2023 IRP	0.257	0.677
Spring 2023 IRP	0.201	0.766
Summer 2023 IRP	0.195	1.796
Fall 2023 IRP	0.276	0.359

Monte Carlo Simulation

During model execution, the MT model makes time-path-dependent Monte Carlo draws for each stochastic variable based on input parameters. The Monte Carlo draws are percentage deviations from the expected forward value of each variable. The Monte Carlo draws of the stochastic variables among all resource portfolios modeled are the same, which allows for a direct comparison of stochastic results among all resource portfolios being analyzed. In the case of natural gas prices, electricity prices, and regional loads, the MT model applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

Stochastic Portfolio Performance Measures

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from the MT model include:

- Stochastic mean PVRR
- Upper-tail Mean PVRR
- 5th, 90th and 95th percentile PVRR

- Standard deviation
- Risk-adjustment (5% of the 95th percentile)

Stochastic Mean PVRR

The stochastic mean PVRR is the average of system net variable operating costs among 20 iterations, combined with the nominal levelized capital costs and fixed costs corresponding to the LT model for any given resource portfolio. The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, long term contracts, system balancing market purchase expenses and sales revenues, reserve deficiency costs, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources are calculated on a nominal-levelized basis. Other components in the stochastic mean PVRR include CO_2 emission costs for any scenarios that include a CO_2 price assumption. The stochastic mean PVRR, limited by performance constraints of the MT model, is not used directly in portfolio selection; instead, the more granular ST PVRR serves as the base measure of net system cost, modified appropriately by stochastic risk.

Upper-Tail Mean PVRR

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the three highest production costs on a net present value basis. The portfolio's fixed costs, taken from the LT model, are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

5th and 95th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 20 Monte Carlo iterations. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 20 Monte Carlo iterations. The production cost is expressed as a net present value of annual costs over the period 2021 through 2040. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Risk-Adjustment

The MT model outcomes of the 20 stochastic samples are used to calculate a risk-adjustment measuring the relative risk of low-probability, high-cost outcomes. This measure is calculated as five percent of system variable costs from the 95th percentile. This metric expresses a low-probability portfolio cost outcome as a risk premium based on 20 Monte Carlo simulations for each resource portfolio and applied to the hourly-granularity deterministic PVRR. The rationale behind the risk-adjusted PVRR is to have a consolidated cost indicator for portfolio ranking, combining the most precise available system cost and high-end cost-risk concepts.

Forward Price Curve Scenarios

Preferred portfolio variants developed during the portfolio-development process are analyzed in the MT model with up to five price-policy scenarios. Price assumptions for each of these scenarios are subject to short-term volatility and mean reversion stochastic parameters when used in the MT model. The approach for producing wholesale electricity and natural gas price scenarios used for MT model simulations is identical to the approach used to develop price scenarios for the portfolio-development process.

Other Plexos Modeling Methods and Assumptions

Transmission System

The base transmission topology shown in Figure 8.3 is used in each of the three Plexos models, LT, ST and MT. Any transmission upgrades selected by LT and ST model processes that provide incremental transfer capability among bubbles in this topology are part of the portfolio and thus included in the MT stochastics and final ST optimizations.

Resource Adequacy

The reality of modeling large complex power systems in a world of significant variable resources is that availability must be compared to requirements in all modeled periods, as measurements only at peak do not adequately establish system reliability. Consistent with past IRPs, the PRM is a portfolio selection driver adequate to the capabilities of the LT model, but is not used once the initial portfolio is established. ST reliability modifications to the portfolio rely on hourly resource availability and system requirements to directly determine reliability shortfalls and any additional resource need at the hourly level. MT stochastic model runs optimize unit commitment and dispatch logic on the resulting fixed portfolio to meet all requirements, including operating reserve and regulation reserves.

Energy Storage Resources

Storage resources such as battery energy storage systems (BESS), compressed air energy storage (CAES), and flow storage have many potential advantages, including storage for frequency regulation, grid stabilization, transmission loss reduction, reduced transmission congestion, renewable energy smoothing, spinning reserve, peak-shaving, load-levelling, transmission and distribution deferral, and asset utilization.

Each Plexos model (LT/MT/ST) dispatches storage resources endogenously, subject to any applicable constraints, for example requirements to charge from onsite solar or for the combined solar and storage output and reserves to remain within a single interconnection limit. The model can deploy energy storage for the most cost-effective uses, including any combination of load ramping and leveling, reserve carrying, and to complement the benefits of renewable resource additions, particularly co-located renewables.

Other Cost and Risk Considerations

In addition to reviewing the risk-adjustment, ENS, and CO_2 emissions data, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

Fuel Source Diversity
PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, storage resources, DSM resources and market purchases.

Customer Rate Impacts
To derive a rate impact measure, PacifiCorp computes the change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the risk adjusted PVRR results from the models and capital costs on a nominal levelized basis. While this approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for rate-making purposes.

Market Reliance
To assess market reliance risk, PacifiCorp quantifies market purchases for each portfolio allowing comparisons among cases in Chapter 9 – Modeling and Portfolio Selection Results. Starting in the 2021 IRP, market purchases were restricted compared to past IRPs, as described in Volume I, Chapter 7 (Resource Options).

Portfolio Selection

Portfolios are measured for relative performance regarding system costs, risk-adjusted system costs, ENS and CO_2 emissions. The risk adjusted PVRR accounts for relative upper tail stochastic risk among portfolios.

Each portfolio under examination at a given step in the analysis is compared based on cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include upper-tail PVRR, risk-adjusted PVRR, ENS and emissions. As noted above, market reliance risk was also evaluated. The comparisons of outcomes are detailed, ranked, and assessed in the next chapter.

Additional quantitative analysis can be performed to further assess the relative differences among top-performing portfolios; qualitative analysis can also be considered where appropriate during portfolio selection on the basis of known factors that could not be readily captured in models.

Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps. For the 2023 IRP natural gas resources are available in the endogenous LT model for selection, a change from the 2021 IRP.

During the final screening process, the results of any further resource portfolio developments will be ranked by risk-adjusted PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the five price-policy price curve scenarios. Resource portfolios with the lowest risk-adjusted PVRR receive the highest rank. Final screening also considers system cost PVRR data from the Plexos models and other comparative portfolio analysis. At this stage, PacifiCorp reviews additional metrics from the models looking to identify if ENS and CO_2 emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted PVRR basis.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2021 IRP, organized here into major development categories:

- Initial Portfolios
  - P-series
- Preferred Portfolio Selection
  - Top Performing Portfolio
  - Preferred Portfolio Variants
- Washington Portfolios and Sensitivities[10]

Additional portfolio detail can be found in Volume II, Appendix I (Capacity Expansion Results).

Initial Portfolios

Informed by the public-input process, the P-series cases endogenously explore a multitude of potentially significant interactions among retirement options including the potential to convert coal units to natural gas operations, retire units prior to end-of-life, install carbon-capture equipment on coal-fired facilities, or retire units at end-of-life. In addition to the core functionality of selecting the optimal timing, size, and location of proxy resources, in the 2023 IRP Plexos also optimizes natural gas retirements. As in the 2021 IRP, the modeling includes a wide range of transmission options for selection, assessed simultaneously with all other competing elements. The initial portfolios also consider how resource selections change with price-policy assumptions that deviate from the medium natural gas price and medium CO_2 price assumptions used to develop many resource portfolios. All the initial portfolios rely on the combined capabilities of three optimization models within Plexos, the LT model, MT model and ST model.

In response to stakeholder feedback, new natural gas proxy resources were made available for selection in the Initial Portfolios. There are however considerable stranded-cost risks associated with planning a system that is reliant on new natural gas resources with depreciable lives ranging between 30 to 40 years (i.e., a new gas-fired resource placed in service in 2030 would be depreciated as late as 2070). It is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such a facility in many parts of PacifiCorp's service territory.

[10] Informational portfolios that are not eligible for selection as the state-wide preferred portfolio. For the purposes of the state of Washington, these additional portfolios are not strictly required for this filing. However, they are provided as a point of reference leading up to the Annual Clean Energy Progress Report to be filed by July 1, 2023. *See* WAC 480-100-650(3).

Further, PacifiCorp observed that in the 2020AS RFP there were no bids for new natural gas resources. Therefore, new natural gas proxy resources were not made available for selection in any of Initial Portfolios. Therefore, when considering current state policies and the consistent trajectory of federal policy over the past 10-20 years, careful consideration must be given to natural gas selections among the competing portfolios.

Portfolios generated with SCGHG price-policy assumptions are consistent with RCW19.280.030 in Washington.

Table 8.11 provides the initial portfolio definitions for this IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Volume II, Appendix I (Capacity Expansion Results).

Table 8.11 – Initial Portfolio Case Definitions

Case Type(a)	Price-Policy	Existing Coal(b)	Existing Gas(b)	Other Existing Resources	Proxy Resources(c)
P	MM	Optimized	Optimized	End of Life	All allowed
P	MN	Optimized	Optimized	End of Life	All allowed
P	LN	Optimized	Optimized	End of Life	All allowed
P	HH	Optimized	Optimized	End of Life	All allowed
P	SC	Optimized	Optimized	End of Life	All allowed

(a) "P" refers generically to "portfolio". Studies are named in the format "P-MM", for example, meaning the initial portfolio run under medium natural gas, medium carbon price assumptions.
(b) Thermal coal and gas resources are endogenously optimized for retirements, conversions and technology installations.
(c) Optimized proxy portfolio selections include renewables, off-shore wind, storage, natural gas, transmission, DSM, purchases and sales, etc.

All initial portfolios consider variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or CCUS retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing.

P-series (optimized retirements, conversions, and technology installations)

P-series portfolios are fully optimized using the best available input data and assumptions regarding requirements and constraints. The P-MM case represents a reasonably likely future that assumes medium gas prices and a medium CO_2 price proxy for future carbon emissions policy. In this series, coal and natural gas retirement timing is optimized, whereas other existing resources are assumed to operate through end of life; contracts expire at the end of their term. Based on the logic of optimization modeling, P-series cases are expected to perform well compared to other case types within the same price-policy environment assumptions given that the models will have the most latitude to find a low-cost portfolio solution. The P-series of cases includes a unique portfolio developed under each of the five price-policy scenarios.

Preferred Portfolio Selection Cases

Certain additional cases were developed directly from the top-performing case (P-MM) based on analysis of portfolios from the twenty initial cases as described above to evaluate the impacts of specific future scenarios not considered elsewhere, but which may be adopted into the preferred portfolio if the analysis warrants their inclusion. In the 2023 IRP, there are eight preferred portfolio selection cases referred to as the "P Variants" as shown in Table 8.12:

Table 8.12 – Preferred Portfolio Variants

Portfolio	Description
P01-JB3-4 GC	Early conversion of Jim Bridger 3 & 4 to gas-fired
P02-JB3-4 EOL	Jim Bridger 3 & 4 remain coal-fired through end of life
P03-Hunter3-SCR	SCR installed on Hunter 3 instead of SNCR
P04-Huntington RET28	Early retirement of Huntington 1 in 2028
P05-No NUC	Nuclear selections replaced with non-emitting peakers
P06-No Forward Tech	Nuclear and non-emitting peakers replaced with non-gas options
P07-D3-D2 32	Delay D3 and D2.2 transmission until 2032
P08-No D3-D2	Exclude selection of D3 and D2.2 transmission
P09-No WY OTR	Assume Wyoming is not subject to OTR
P10-Offshore Wind	Includes offshore wind project
P11-Max NG	Nuclear and non-emitting peakers replaced with natural gas
P12-RET Coal 30 NG 40	Retire all coal by year-end 2029; retire all natural gas by year-end 2039
P13-All EE	Includes all energy efficiency programs
P14-All GW	Includes all Energy Gateway transmission options
P15-No GWS	Exclude Energy Gateway South
P16-No B2H	Exclude selection of B2H transmission
P17-Col3-4 RET25	Colstrip units 3 and 4 retire end of 2025
P18-Cluster East	Enable Cluster 1 Clover transmission in Area 5/6/7
P19-Cluster West	Enable Cluster 1 Area 12 transmission and resources
P20-JB3-4 CCUS	JB3-4 converts to CCUS in 2028

Each variant case begins with inputs and assumptions identical to the preferred portfolio (P-MM), which is the top performing portfolio.

P01-JB3-4 GC

This variant tests a 2026 gas conversion assumption for Jim Bridger Units 3 and 4, accelerating the conversion to natural gas fueling from 2030. The study is re-optimized with the accelerated assumption.

P02-JB3-4 EOL[11]

In this variant, Jim Bridger Units 3 and 4 are assumed to run as coal-fired units through end-of-life. This sensitivity evaluates the cost and risk merits of this strategy by excluding early retirements or conversions, re-optimizing the portfolio, and comparing outcomes.

P03-Hunter3-SCR

This variant replaces the Hunter 3 installation of SNCR with SCR to establish the net cost/benefit of the more expensive SCR technology.

[11] P02-JB3-4 EOL variant is defined as the *reference case* per Wyoming Order, Docket No. 90000-144-XI-19 (Record No. 15280). Additional information regarding the reference case is given in Chapter 9 (Modeling and Portfolio Selection Results).

P04-Huntington RET28

This variant tests the potential system cost or benefit of retiring Huntington unit 1 in 2028, four years earlier than in the preferred portfolio. Based on the early retirement date, the portfolio is re-optimized in the absence of this unit.

P05-No NUC

This case removes the Natrium™ demonstration project in 2030, and subsequent 2031 and 2033 nuclear plants using the same Natrium™ technology from the preferred portfolio. The portfolio is then re-optimized to determine a portfolio necessary to maintain reliability. The purpose of the sensitivity is to evaluate possible alternatives in the absence of nuclear resource options. Additionally, this sensitivity seeks to evaluate the potential risk that these projects are unable to achieve online and operating status for any reason.

P06-No Forward Tech

This variant removes both nuclear and non-emitting peaking resources to assess the potential for an alternate pathway to reliability. The study disallows new gas options (as compared to the "Max NG" variant described below).

P07-D3-D2 32

The delay of transmission projects D3 and D2.2 is evaluated in this sensitivity by assuming a 2032 online year rather than 2029 as in the preferred portfolio. The study is re-optimized with the decelerated assumption.

P08-No D3-D2

In variant P08-No D3-D2, the D3 and D2.2 transmission projects are not allowed to be selected as part of the optimal capacity expansion plan. The portfolio is re-optimized in the absence of these projects.

P09-No WY OTR

Currently, the status of Wyoming regarding the Ozone Transport Rule is not completely settled. The 2023 IRP conservatively assumes that Wyoming will be included among those states subject to OTR restrictions on NOx emissions beginning in 2024. This counterfactual analysis removes Wyoming from OTR constraints to identify the impacts on modeled outcomes.

P10-Offshore Wind

In the P-series cases, offshore wind was available for portfolio selection beginning in year 2028, though it is reliant upon transmission upgrades that may not be available until later. As offshore wind has not been endogenously selected, a minimum of 1000 MW was required to be selected. Additionally, the necessary on-shore transmission required to enable offshore wind was available for selection by offshore wind or by any other appropriately located proxy resources to ensure that co-located resources could be selected to complement the offshore wind and that it is competitive with other options. As offshore wind was not selected for the preferred portfolio, this counterfactual includes it, and is used to assess system impacts and the magnitude of the costs and benefits associated with offshore wind.

P11-Max NG

In this sensitivity, new gas peaking resources replace non-emitting peaking resources and new combined cycle combustion turbines replace advanced nuclear resources. As natural gas resources were available for selection in the base model assumptions but were not selected, this sensitivity is the counterfactual, wherein natural gas resources are forced into the solution to assess the magnitude of the impact.

P12-RET Coal 30 NG 40

This variant features the retirement of all coal resources by 2030 using an optimized retirement strategy within the first seven years of the planning horizon. Similarly, natural gas resources also retire by 2040. Other existing resources continue as usual.

P13-All EE

Variant P13-All EE includes all energy efficiency, providing a bookend assessment of the cost and risk trade-off as well as portfolio impacts.

P14-All GW

The 2017, 2019 and 2021 IRPs have each identified Energy Gateway projects and collectively point toward the need for future transmission expansion to meet future load and provide cost-effectives alternatives to pollution-emitting resources. This sensitivity examines the relative costs and benefits of including all major components of Energy Gateway and accompanying resource selections.

P15-No GWS

The Energy Gateway South and associated Energy Gateway Segment D.1[12] projects directly enable 2,030 MW (nameplate) of interconnected resources; most of which are wind resources procured in PacifiCorp's 2020 All-Source RFP. Gateway South is also required for certain interconnection requests in Utah and enables future transmission upgrades. In the P15-No GWS case, both the transmission project and enabled resources and future transmission are removed. The portfolio is re-optimized in the absence of these projects.

P16-No B2H

In this sensitivity the transmission segments associated with the Boardman-to-Hemingway project are removed along with 600 MW (interconnection capability) of enabled resources. The portfolio is re-optimized in the absence of these projects.

P17-Col3-4 RET25

This study includes the retirement of Colstrip units 3 and 4 at the end of 2025, a variance from the preferred portfolio assumption which maintains PacifiCorp's participation share through 2029. The portfolio is re-optimized assuming the accelerated retirements.

P18-Cluster East

The first of two transmission cluster study variants, P18-Cluster East enables five Clover transmission components associated with Cluster 1, Areas 5, 6, and 7, which includes a prerequisite and a related transfer capability increase. The portfolio is re-optimized with this transmission expansion to evaluate portfolio impacts, costs and risks.

[12] Refer to Volume I, Chapter 4 (Transmission) for details regarding these projects.

P19-Cluster West
Similar to P18-Cluster East, the "Cluster West" variant enables Southern Oregon transmission upgrades supporting Cluster 1, Area 12 resources and a transfer capability increase. The portfolio is re-optimized with this transmission expansion to evaluate portfolio impacts, costs and risks.

CCUS Variant (P-20-JB3-4 CCUS)
This study analyzes the impacts of assuming carbon capture utilization and sequestration technology is installed on specific existing coal units in year 2028. Variant P-20-JB3-4 CCUS was run as a counterfactual to preferred portfolio selections.

Washington Portfolios

Washington's CETA legislation indicates four key studies:

- **W-10 CETA** – This study complies with CETA's Clean Energy Transformation Standards. This sensitivity also includes the requirement to use the social cost of greenhouse gases (SC) price-policy assumption in resource acquisition decisions. In Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA compliant outcomes.

- **W-11 Climate Change Counterfactual** - WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change." Please see Appendix A for additional detail regarding how climate change is incorporated into the base forecast. Because the base forecast includes climate change, the 20-year normal sensitivity for Washington is the counterfactual to this case – i.e., a study which does not incorporate specific climate change considerations.

- **W-12 Maximum Customer Benefit** - WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals." The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and includes all available Washington energy efficiency and demand response. The study also removes Yakima and Walla Walla area transmission and relies on increased small-scale renewables.

- **P-SC Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards. This case is identical to the initial P-SC price-policy scenario study conducted among the initial studies. Like the CETA-compliant W-10 CETA portfolio, this sensitivity includes the requirement to use the social cost of greenhouse gases (SC) price-policy assumption in resource acquisition decisions. In

Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA compliant outcomes.

Each of these studies is most pertinent to the State of Washington and are further discussed in Chapter 9 (Modeling and Portfolio Selection Results).

Sensitivity Case Definitions

PacifiCorp identified eight sensitivities outlined in Table 8.13 and discussed further in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).

Table 8.13 – Sensitivity Case Definitions

Case	Description	Load Forecast	Private Generation	Resources	CO_2 Policy
S-01	High Load	High	Low	Optimized	Medium gas / Medium CO_2
S-02	Low Load	Low	High	Optimized	Medium gas / Medium CO_2
S-03	1 in 20 Load Growth	1 in 20	Base	Optimized	Medium gas / Medium CO_2
S-04	20-year Normal	20yr Normal	Base	Optimized	Medium gas / Medium CO_2
S-05	High Private Generation	Base	High	Optimized	Medium gas / Medium CO_2
S-06	Low Private Generation	Base	Low	Optimized	Medium gas / Medium CO_2
S-07	Business Plan	Base	Base	Align first three years	Medium gas / Medium CO_2
S-08	New Load	Flat Load Increase	Base	Optimized	Medium gas / Medium CO_2
W-10	CETA	Base	Base	Added for CETA	WA resources under SC
W-11	Climate Change Counterfactual	No climate change	Base	Optimized	WA resources under SC
W-12	Max Customer Benefit	Base	Base	Modified	WA resources under SC

Load Sensitivities (S01, S02, S03, S04)

PacifiCorp includes four different load forecast sensitivities. The high load forecast sensitivity (S01) reflects optimistic economic growth assumptions from IHS Global Insight, low private generation and the upper bound of the 95% prediction interval for the model error bands. The low load forecast sensitivity (S02) reflects pessimistic economic growth assumptions from IHS Global Insight, high private generation and the lower bound of the 95% prediction interval for the model error bands.

The third load forecast sensitivity (S03) is a 1-in-20 (5 percent probability) extreme weather scenario. The 1-in-20 peak weather scenario is defined as the year for which the peak has the chance of occurring once in 20 years. This sensitivity is based on 1-in-20 peak weather for July in each state. Figure 8.6 compares the low, high, and 1-in-20 load sensitivities, net of base case private generation levels, alongside the base case load forecast.

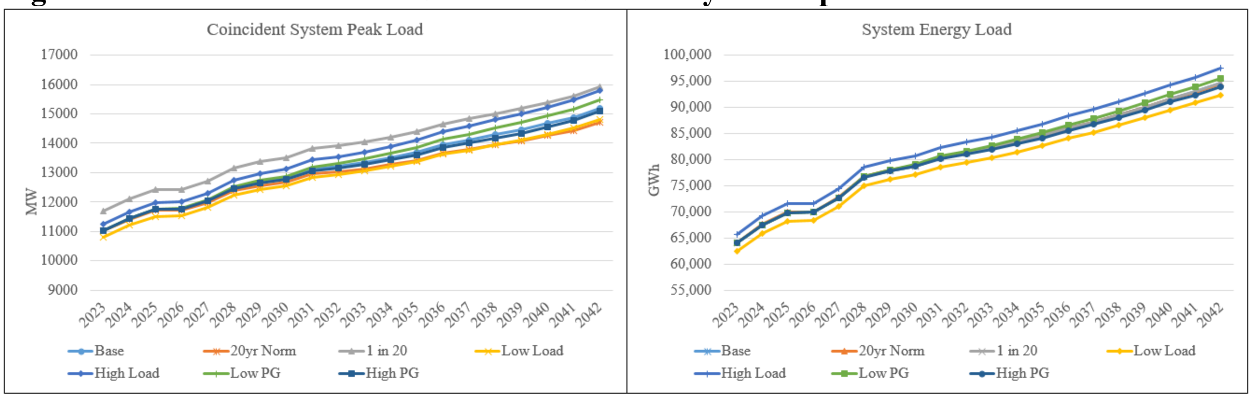
The fourth load forecast sensitivity (S04) is the 20-year normal scenario, which is based on normal weather, which is defined by the 20-year period of 2002 through 2021 (50^{th} percentile). In prior IRP cycles, this scenario is what was traditionally used as the base IRP load forecast.

Private Generation Sensitivities (S05, S06)

Two private generation sensitivities are analyzed. As compared to base private generation penetration levels that incorporated annual reductions in technology costs, the high private generation sensitivity (S05) reflects more aggressive technology cost reduction assumptions, greater technology performance levels, and higher retail electricity rates. In contrast, the low private generation sensitivity (S06) reflects lesser reductions in technology costs, reduced technology performance levels, and lower retail electricity rates.

Business Plan Sensitivity (S07)
Case S07 complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's 2020 Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with those identified in the preferred portfolio. All other resource selections are optimized using the Plexos models.

Figure 8.6 - Load and Private Generation Sensitivity Assumptions



New Load Sensitivity (S08)
PacifiCorp has been approached by customers looking to add a significant volume of new load within PacifiCorp's west balancing authority area. This sensitivity analyzes the level of incremental transmission and new resources that would be needed to meet an incremental 3,000 MW of new load coming online in 2033. The results of this sensitivity will be useful to inform the company's need to initiate planning and permitting activities required to be ready to construct long-lead transmission investments that could be used to reliably serve significant increase in new load. The resource selections from this sensitivity will also provide an indicator of the new resource procurement required to serve these customers. For this sensitivity, incremental transmission and new resource selections are optimized using the Plexos models.

CHAPTER 9 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio that builds on its vision to deliver energy affordably, reliably, and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity maintaining substantial investment in energy efficiency and demand response programs.
- PacifiCorp's selection of the 2023 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process. The preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, advanced nuclear, and non-emitting peaking resources.
- The 2023 IRP preferred portfolio includes new resources from the 2020 All-Source Request for Proposals (RFP). These projects include 1,792 MW of wind, 495 MW of solar additions with 200 MW of battery storage capacity. These resources will come online in the 2024-to-2025 timeframe. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River I (50 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022AS RFP is currently soliciting and evaluating resources to fulfill.
- The 2023 IRP preferred portfolio also includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. By the end of 2032, the preferred portfolio includes 1,000 MW of additional advanced nuclear resources, and through 2037, the preferred portfolio includes 1,240 MW of non-emitting peaking resources. Advancement of these two technologies will be critical to the planned transition of our coal resources in a way that will minimize impacts to our employees and our communities. Over the 20-year planning horizon, the 2023 IRP preferred portfolio includes 9,114 MW of new wind and 7,855 MW of new solar.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the 2023 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2023 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59-mile, high-voltage (230-kilovolt) transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.
- The 2023 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway ("B2H"), which connects the Longhorn substation near the town of Boardman in Oregon to the Hemingway substation in Idaho, which will come online in 2026. By exchanging certain transmission assets with Idaho Power Company, PacifiCorp will receive additional transmission rights between Hemingway and the

Populus substation in Idaho, which is closely tied to existing and future PacifiCorp transmission connecting to Utah and Wyoming. At the Oregon end of the B2H line, additional transmission upgrades are planned to connect B2H to growing loads.

- New since the 2021 IRP, the 2023 IRP preferred portfolio includes a 200-mile high-voltage 500-kilovolt transmission line from Anticline substation in central Wyoming to Populus substation in southeastern Idaho known as Energy Gateway West Sub-Segment D.3, planned to come online in 2028.
- Further, the 2021 IRP preferred portfolio includes near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to serve our customers. New for the 2023 IRP, many of these transmission upgrades and the accompanying resources reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. By evaluating all newly proposed resource additions in an area at the same time, the cluster study process identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. As a result, many of the transmission upgrades and resource additions in the first five years of the IRP preferred portfolio reflect cluster study requests submitted in the past two years.
- Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement or gas conversion of 13 units by 2030 and 20 units by year-end 2032. The final two coal units retire by 2039, or three years ahead of the end of the planning period, with the path to decarbonization supported by new non-emitting technologies.
- In addition to the coal unit exits, retirements, and gas conversions outlined above, the preferred portfolio reflects 2,660 MW natural gas retirements through 2042. This includes Gadsby at the end of 2032, Naughton Units 1, 2, and 3 at the end of 2036, Hermiston at the end of 2036, and Jim Bridger Units 1, 2, 3, and 4 at the end of 2037.
- In the current 2023 IRP emissions are higher than projected in the 2021 IRP until 2032, this is a result of higher load forecast in the 2023 IRP. By 2032, average annual CO_2e emissions are down 21 percent relative to the 2021 IRP preferred portfolio. By 2040 emissions are comparable to the 2021 IRP while generation has increased by 31% showing that the overall emissions rate is lower under 2023 IRP portfolio. By the end of the planning horizon, system CO_2e emissions are projected to fall from 41.5 million metric tons in 2023 to 6.2 million tons in 2042—a reduction of 85 percent

Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the Plexos modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp's preferred portfolio selection process and presents the 2023 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio, cost and risk analysis for the: (1) initial portfolios; (2) the variants of the top performing initial portfolio and (3) the preferred portfolio selection. The final preferred portfolio selection is informed by all relevant modeling results. This chapter also presents modeling results for additional scenarios required under Washington's Clean Energy Transformation Act (CETA)[1].

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp's portfolio evaluation processes. Stochastic modeling results are also summarized in Volume II, Appendix J (Stochastic Simulation Results).

Initial Portfolio Development

The following discussion begins with an examination of initial portfolios exploring variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or carbon capture, utilization and storage (CCUS) retrofit for certain units. The initial portfolios differ based on natural gas and proxy CO_2 policy assumptions, resulting in uniquely optimization combinations of resources, transmission and thermal retirement options.

Following the initial portfolios, PacifiCorp examined variants of the top-performing case with eight additional portfolios referred to as the P-MM variants. All portfolios are examined with a granular assessment of reliability requirements through the production of hourly deterministic ST studies for every year over the 20-year planning horizon. Similar to the initial portfolios, this provides twenty years of hourly ST reliability assessment data used to inform the portfolios and ensure they are reliable.

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), PacifiCorp evaluated eight variants of the top-performing P-MM initial portfolio. Final selection of the top-performing portfolio and preferred portfolio selection also included an assessment of compliance with CETA.

Initial Portfolio Development

The following tables and figures present resource additions and system costs for the initial and variant portfolios. Note that no tables are shown for SCR or CCUS installatioins on coal units. As no SCR or CCUS installations were selected in optimized portfolio, the only studies representing SCR or CCUS are the counterfactual studies for these cases where each technolohy was forced to be built by the model. These counterfactuals are explained in detail later in this chapter.

[1] Due to Washington's IRP and related filing schedules, this 2023 IRP was filed in Washington as PacifiCorp's "Washington 2021 Integrated Resource Plan Two-Year Progress Report". Volume II, Appendix O provides addional detail relevant to Washington requirements.

Table 9.1 – Non-Emiting Peaking (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	-	-	-	-	303	-	-	-	-	1,240	-	-	-	-	-
P-MN		-	-	-	-	-	-	-	-	-	-	-	303	578	345	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P-HH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	951	-	-	-	-	-
P-SC	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	895	-	303	303	-	-	345	289	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P07-D3-D2 32	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	606	-	-	-	-	-	-	289	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	606	-	-	-	-	-	345	1,790	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.2 - DSM Energy Efficiency (Installed Capacity MW)

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	123	220	259	197	216	219	240	258	637	103	160	170	161	281	586	163	170	165	139	412
P-MN	123	220	259	198	217	221	243	259	637	105	160	170	161	288	586	164	170	165	139	412
P-MM	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P-HH	123	220	259	210	229	234	255	266	675	116	161	185	162	289	594	165	187	176	172	671
P-SC	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429
P01-JB3-4 GC	123	220	259	208	228	219	241	259	637	116	163	172	163	288	542	163	183	175	141	428
P02-JB3-4 EOL	123	220	259	208	228	219	240	258	637	115	161	171	161	288	542	163	184	176	141	428
P03-Hunter3-SCR	123	220	259	198	216	220	240	258	637	105	149	170	161	288	586	163	186	176	143	429
P04-Huntington RET28	123	220	259	208	228	219	240	258	637	109	161	171	161	288	542	163	184	176	141	428
P05-No NUC	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429
P06-No Forward Tech	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429
P07-D3-D2 32	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P08-No D3-D2	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P09-No WY OTR	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P10-Offshore Wind	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P11-Max NG	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P12-RET Coal 30 NG 40	123	954	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P13-All EE	123	220	259	289	330	334	392	457	1,016	215	301	283	292	457	816	230	253	241	343	1,231
P14-All GW	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P15-No GWS	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P16-No B2H	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P17-Col3-4 RET25	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P18-Cluster East	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P19-Cluster West	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P20-JB3-4 CCUS	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426

Table 9.3 – DSM Demand Response (Installed Capacity MW)

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	72	39	143	38	161	120	33	16	33	-	-	-	51	-	-	170	19	19	-	-
P-MN	72	39	152	99	126	94	27	13	35	-	-	-	-	-	1	228	19	19	-	-
P-MM	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P-HH	72	39	154	119	117	81	26	-	37	5	13	12	26	-	-	239	22	19	-	-
P-SC	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-
P01-JB3-4 GC	72	220	193	6	83	61	41	10	8	-	-	-	117	-	-	121	21	20	-	-
P02-JB3-4 EOL	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-
P03-Hunter3-SCR	72	53	167	105	111	90	31	13	35	-	-	2	-	-	-	225	19	38	-	-
P04-Huntington RET28	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-
P05-No NUC	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-
P06-No Forward Tech	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-
P07-D3-D2 32	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P08-No D3-D2	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P09-No WY OTR	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P10-Offshore Wind	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P11-Max NG	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P12-RET Coal 30 NG 40	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P13-All EE	72	39	152	109	119	91	29	13	35	-	1	-	2	-	4	265	70	20	-	778
P14-All GW	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P15-No GWS	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P16-No B2H	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P17-Col3-4 RET25	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P18-Cluster East	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P19-Cluster West	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P20-JB3-4 CCUS	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-

Table 9.4 – Renewable Wind (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	194	1,717	-	-	-	500	-	11	5,477	1,821	-	-	-	-	-	-	-	-	-
P-MN	-	194	1,717	-	-	-	500	-	-	6,025	3,565	-	450	-	-	-	-	-	-	-
P-MM	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P-HH	-	194	1,717	-	-	174	500	-	-	7,922	2,321	-	-	-	-	-	-	-	-	-
P-SC	-	194	1,717	-	-	457	500	-	-	6,486	3,607	-	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P02-JB3-4 EOL	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P03-Hunter3-SCR	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P04-Huntington RET28	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P05-No NUC	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P06-No Forward Tech	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P07-D3-D2 32	-	194	1,937	-	100	300	-	-	-	6,165	1,755	-	-	-	-	-	-	-	-	-
P08-No D3-D2	-	194	1,937	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-
P09-No WY OTR	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P10-Offshore Wind	-	194	1,937	-	100	300	1,900	-	-	2,683	1,459	-	-	-	540	-	-	-	-	-
P11-Max NG	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P12-RET Coal 30 NG 40	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	676	-	-	-	-	-
P13-All EE	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P14-All GW	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P15-No GWS	-	194	296	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-
P16-No B2H	-	194	1,937	-	100	-	1,900	400	-	2,783	959	-	-	-	540	-	-	-	-	-
P17-Col3-4 RET25	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P18-Cluster East	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P19-Cluster West	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P20-JB3-4 CCUS	-	194	1,937	-	100	300	1,900	-	-	2,733	1,359	-	-	-	540	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.5 – Renewable Solar (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	1,469	1,600	-	2,519	1,298	-	288	241	-	-	-	-	1,400	-	-	-	-	-
P-MN	-	-	1,469	1,600	-	2,470	1,298	-	254	941	-	-	-	-	600	-	-	-	-	-
P-MM	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P-HH	-	-	1,469	1,600	-	3,006	1,298	-	4	1,288	241	-	-	-	-	-	-	-	-	-
P-SC	-	-	1,469	1,600	-	2,589	1,298	-	108	600	-	841	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P02-JB3-4 EOL	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P03-Hunter3-SCR	-	-	1,469	2,524	483	1,832	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P04-Huntington RET28	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P05-No NUC	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P06-No Forward Tech	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	600	-	-	-	-	-
P07-D3-D2 32	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P08-No D3-D2	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P09-No WY OTR	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P10-Offshore Wind	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P11-Max NG	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P13-All EE	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P14-All GW	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P15-No GWS	-	-	1,469	2,224	483	2,307	600	-	200	972	-	300	-	-	-	-	-	-	-	-
P16-No B2H	-	-	1,469	2,524	483	1,507	600	-	-	972	600	300	-	-	-	-	-	-	-	-
P17-Col3-4 RET25	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P18-Cluster East	-	-	1,469	2,524	483	1,907	2,373	-	-	972	-	300	-	-	-	-	-	-	-	-
P19-Cluster West	-	-	1,469	2,524	483	2,406	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P20-JB3-4 CCUS	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.6 – Battery Storage (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	954	1,600	160	2,008	1,647	-	-	-	400	-	-	-	2,560	-	-	-	-	-
P-MN	-	-	954	1,600	-	2,304	1,647	-	-	600	-	-	-	-	2,356	-	-	-	-	-
P-MM	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P-HH	-	-	954	1,600	-	2,599	1,647	-	-	600	-	-	-	-	1,541	-	-	-	-	-
P-SC	-	-	954	1,600	-	1,979	1,647	-	-	600	-	-	-	-	1,207	-	-	-	-	-
P01-JB3-4 GC	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P02-JB3-4 EOL	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P03-Hunter3-SCR	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P04-Huntington RET28	-	-	954	2,929	628	2,300	1,149	-	-	-	-	-	-	-	100	-	-	-	-	-
P05-No NUC	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-
P06-No Forward Tech	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-
P07-D3-D2 32	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	(196)
P08-No D3-D2	-	-	954	2,929	628	1,900	1,149	-	-	800	150	-	-	-	200	-	-	-	-	-
P09-No WY OTR	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P10-Offshore Wind	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	500	-	-	-	-	-
P11-Max NG	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	1,323	-	-	-	-	(196)
P13-All EE	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P14-All GW	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P15-No GWS	-	-	954	2,629	628	2,500	1,349	-	-	800	150	-	-	-	200	-	-	-	-	-
P16-No B2H	-	-	954	2,929	1,352	1,900	1,149	-	-	-	750	-	-	-	200	-	-	-	-	-
P17-Col3-4 RET25	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P18-Cluster East	-	-	954	2,929	628	1,900	3,322	-	-	-	150	-	-	-	200	-	-	-	-	-
P19-Cluster West	-	-	954	2,929	628	2,399	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P20-JB3-4 CCUS	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.7 – Battery, Long Duration (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P-MN	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P-HH	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P-SC	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	-	-	300	450	-	-	-	200	-	-	-	-	-
P07-D3-D2 32	-	-	600	-	-	-	-	-	-	-	150	-	(600)	-	200	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.8 – Nuclear (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P-HH	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	500	-	-	-	-	-
P-SC	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P07-D3-D2 32	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.9 – Coal End-of-life Retirements[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-MM	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-HH	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-SC	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-
P01-JB3-4 GC	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	(699)	-	(330)	-	-
P02-JB3-4 EOL	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P03-Hunter3-SCR	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P04-Huntington RET28	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P05-No NUC	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P06-No Forward Tech	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P07-D3-D2 32	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P08-No D3-D2	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P09-No WY OTR	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P10-Offshore Wind	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P11-Max NG	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P12-RET Coal 30 NG 40	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P14-All GW	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P15-No GWS	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	(330)	-	-	-	-	-
P16-No B2H	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P17-Col3-4 RET25	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P18-Cluster East	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P19-Cluster West	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P20-JB3-4 CCUS	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-

1 – Negative values indicate retirement of coal fueled capacity

Table 9.10 – Coal with SNCR Installation[1,2]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	2,067	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P-MM	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P-HH	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P-SC	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P01-JB3-4 GC	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P02-JB3-4 EOL	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P03-Hunter3-SCR	-	-	-	1,864	-	-	-	-	-	(418)	(1,178)	-	-	-	-	-	-	(268)	-	-
P04-Huntington RET28	-	-	-	2,335	-	(459)	-	-	-	(418)	(1,190)	-	-	-	-	-	-	(268)	-	-
P05-No NUC	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P06-No Forward Tech	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P07-D3-D2 32	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P08-No D3-D2	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P09-No WY OTR	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P10-Offshore Wind	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P11-Max NG	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P12-RET Coal 30 NG 40	-	-	-	2,067	(450)	-	-	-	-	(418)	(1,199)	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P14-All GW	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P15-No GWS	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	(268)	-	-	-	-	-
P16-No B2H	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P17-Col3-4 RET25	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P18-Cluster East	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P19-Cluster West	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P20-JB3-4 CCUS	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-

1 – Positive values indicate first full year of operations with SNCR installed

2 – Negative values indicate retirement of coal fueled capacity with SNCR

Table 9.11 – Coal to Natural Gas Conversions[1,2]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	713	-	370	598	-	-	699	-	(330)	-	-	-	-	(370)	(1,413)	-	(268)	-	-
P-MN	-	713	-	370	-	-	-	340	(354)	-	-	-	-	(160)	(210)	(699)	-	-	-	-
P-MM	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P-HH	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P-SC	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-
P01-JB3-4 GC	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-
P02-JB3-4 EOL	-	713	-	1,069	-	-	-	-	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P03-Hunter3-SCR	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P04-Huntington RET28	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P05-No NUC	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P06-No Forward Tech	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P07-D3-D2 32	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P08-No D3-D2	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P09-No WY OTR	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P10-Offshore Wind	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P11-Max NG	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P12-RET Coal 30 NG 40	-	713	-	370	598	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	(598)	-	-
P13-All EE	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P14-All GW	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P15-No GWS	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(1,783)	-	-	-	-	-
P16-No B2H	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P17-Col3-4 RET25	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P18-Cluster East	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P19-Cluster West	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P20-JB3-4 CCUS	-	713	-	370	-	-	-	349	-	-	-	-	-	-	(370)	(1,062)	-	-	-	-

1 – Positive values indicate first full year of natural gas-fueled operation

2 – Negative values indicate retirement of gas-converted capacity

Preferred Portfolio Variants

Driven by emergent federal and state law and stakeholder interest, the 2023 IRP features 20 preferred portfolio variants developed to analyze key resource and transmission decisions. This is a 150% increase over the 8 variants represented in the 2021 IRP.[2] The preferred portfolio variants are summarized in Table 9.12.

Table 9.12 – Preferred Portfolio Selection

Portfolio	Description
P01-JB3-4 GC	Early conversion of Jim Bridger 3 & 4 to gas-fired
P02-JB3-4 EOL	Jim Bridger 3 & 4 remain coal-fired through end of life
P03-Hunter3-SCR	SCR installed on Hunter 3 instead of SNCR
P04-Huntington RET28	Early retirement of Huntington 1 in 2028
P05-No NUC	Nuclear selections replaced with non-emitting peakers
P06-No Forward Tech	Nuclear and non-emitting peakers replaced with non-natural gas options
P07-D3-D2 32	Delay D3 and D2.2 transmission until 2032
P08-No D3-D2	Exclude selection of D3 and D2.2 transmission
P09-No WY OTR	Assume Wyoming is not subject to OTR
P10-Offshore Wind	Include offshore wind project
P11-Max NG	Nuclear and non-emitting peakers replaced with natural gas
P12-RET Coal 30 NG	Retire all coal by year-end 2029; retire all natural gas by year-end 2039
P13-All EE	Includes all energy efficiency programs
P14-All GW	Includes all Energy Gateway transmission segments
P15-No GWS	Exclude Energy Gateway South
P16-No B2H	Exclude selection of B2H transmission
P17-Col3-4 RET25	Colstrip units 3 and 4 retire end of 2025
P18-Cluster East	Enable Cluster 1 Areas 5, 6, and 7: resources and transfer capability in Clover, Utah.
P19-Cluster West	Enable Cluster 1 Area 12: resources and transfer capability in southern Oregon.
P20-JB3-4 CCUS	JB3-4 converts to CCUS in 2028

Preferred Portfolio Variants Discussion

[2] In addition to more than doubling the number of variants, these studies also represent a sea change in optimization complexity. In particular, the Ozone Transport Rule's (OTR) recursive nature complicates model math and performance. The OTR and Inflation Reduction Act together represent many hundreds of pages of detail, and PacifiCorp is highly confident that modeling requirements will evolve significantly as these policy changes are absorbed by the energy industry.

Table 9.13 – Initial and Variant Cases Under Medium Gas/ Medium CO2

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - MM	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P-MM	37,438	$0	3	37,305	$0	3	0.0020%	0.00000%	12	330,442	0	11
P01-JB3-4 GC	38,031	$593	8	37,903	$598	8	0.0012%	-0.00080%	1	323,314	-7,128	4
P02-JB3-4 EOL	38,503	$1,065	11	38,358	$1,052	10	0.0012%	-0.00076%	3	342,026	11,584	14
P03-Hunter3-SCR	37,705	$267	6	37,562	$257	6	0.0019%	-0.00008%	5	346,847	16,404	15
P04-Huntington RET28	37,598	$160	5	37,465	$160	4	0.0012%	-0.00079%	2	328,688	-1,754	9
P05-No NUC	39,086	$1,648	17	39,208	$1,903	18	0.0015%	-0.00051%	4	355,234	24,792	17
P06-No Forward Tech	38,771	$1,333	13	38,876	$1,570	13	0.0019%	-0.00006%	6	353,676	23,233	16
P07-D3-D2 32	37,419	($19)	2	37,235	($70)	2	0.0020%	-0.00004%	7	331,885	1,442	13
P08-No D3-D2	39,212	$1,774	19	39,228	$1,923	19	0.0020%	0.00002%	16	361,637	31,195	18
P09-No WY OTR	36,808	($630)	1	36,632	($673)	1	0.0020%	-0.00004%	8	362,623	32,181	19
P10-Offshore Wind	38,770	$1,333	12	39,018	$1,713	15	0.0020%	0.00004%	18	327,328	-3,114	8
P11-Max NG	38,342	$904	10	38,466	$1,161	11	0.0029%	0.00095%	21	369,404	38,962	20
P12-RET Coal 30 NG 40	41,263	$3,825	21	41,209	$3,904	21	0.0020%	0.00002%	17	268,786	-61,657	1
P13-All EE	40,613	$3,175	20	40,449	$3,143	20	0.0020%	-0.00001%	10	321,444	-8,998	3
P14-All GW	37,998	$560	7	37,865	$560	7	0.0020%	0.00000%	11	330,335	-108	10
P15-No GWS	38,975	$1,537	15	39,128	$1,822	17	0.0023%	0.00036%	19	383,310	52,867	21
P16-No B2H	39,156	$1,718	18	39,022	$1,716	16	0.0020%	-0.00002%	9	323,894	-6,548	5
P17-Col3-4 RET25	37,511	$73	4	37,511	$206	5	0.0020%	0.00000%	13	326,893	-3,550	7
P18-Cluster East	39,004	$1,566	16	39,004	$1,699	14	0.0020%	0.00001%	14	307,849	-22,593	2
P19-Cluster West	38,075	$637	9	38,075	$770	9	0.0020%	0.00001%	15	324,730	-5,713	6
P20-JB3-4 CCUS	38,781	$1,343	14	38,649	$1,344	12	0.0024%	0.00045%	20	330,442	0	11

Table 9.14 – Initial and Variant Cases Under Low Gas/ Zero CO2

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - LN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P-MM	36,181	$0	2	36,155	$0	2	0.0020%	0.00000%	5	306,945	0	3
P-LN	34,650	($1,532)	1	34,610	($1,545)	1	0.0019%	-0.00014%	4	296,748	-10,197	1
P02-JB3-4 EOL	37,004	$822	5	36,966	$811	4	0.0009%	-0.00106%	1	318,019	11,074	4
P11-Max NG	36,503	$322	3	36,731	$576	3	0.0028%	0.00078%	6	342,480	35,535	5
P16-No B2H	37,102	$920	6	37,070	$915	5	0.0017%	-0.00029%	2	301,689	-5,257	2
P15-No GWS	36,848	$667	4	37,088	$934	6	0.0019%	-0.00014%	3	355,714	48,769	6

Table 9.15 – Initial and Variant Cases Under Medium Gas/ Zero CO2

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - MN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P-MM	36,257	$0	2	36,252	$0	2	0.0020%	0.00000%	2	313,970	0	2
P-MN	35,868	($390)	1	35,726	($526)	1	0.0020%	-0.00004%	1	304,970	(9,000)	1

Table 9.16 – Initial and Variant Cases Under High Gas/ High CO2

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - HH	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2023-2042 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P-MM	45,540	($1,286)	2	45,540	($1,286)	2	0.0020%	0.00105%	4	328,142	-19,555	3
P11-Max NG	48,092	$1,266	5	48,092	$1,266	5	0.0025%	0.00159%	6	355,494	7,798	5
P02-JB3-4 EOL	46,826	$0	4	46,826	$0	4	0.0009%	0.00000%	1	347,697	0	4
P15-No GWS	49,776	$2,949	6	49,776	$2,949	6	0.0018%	0.00091%	3	358,984	11,288	6
P16-No B2H	46,267	($559)	3	46,267	($559)	3	0.0017%	0.00075%	2	324,186	-23,511	2
P-HH	43,782	($3,045)	1	43,782	($3,045)	1	0.0020%	0.00105%	5	305,285	-42,412	1

Jim Bridger Unit 3 and Unit 4 Early Gas Conversion Variant (P01-JB 3-4 GC)

The Jim Bridger 3 and 4 Early Gas Conversion variant changes the conversion date of the Bridger 3 and 4 plants from 2030 to 2026. This variant explores the potential costs or benefits of converting these units to gas earlier, taking into consideration current sunk costs and differences between projected future coal and gas prices.

Figure 9.1 shows the cumulative (at left) and incremental (at right) portfolio changes when these plants convert four years earlier in 2026 compared to the P-MM base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. Since Jim Bridger 3 and 4 continue to operate in both scenarios, just with different fuels, there are only relatively small changes in this portfolio in energy efficiency and demand response.

Figure 9.1 - Increase/(Decrease) in Proxy Resources when Jim Bridger is Gas Converted in 2026 versus 2030

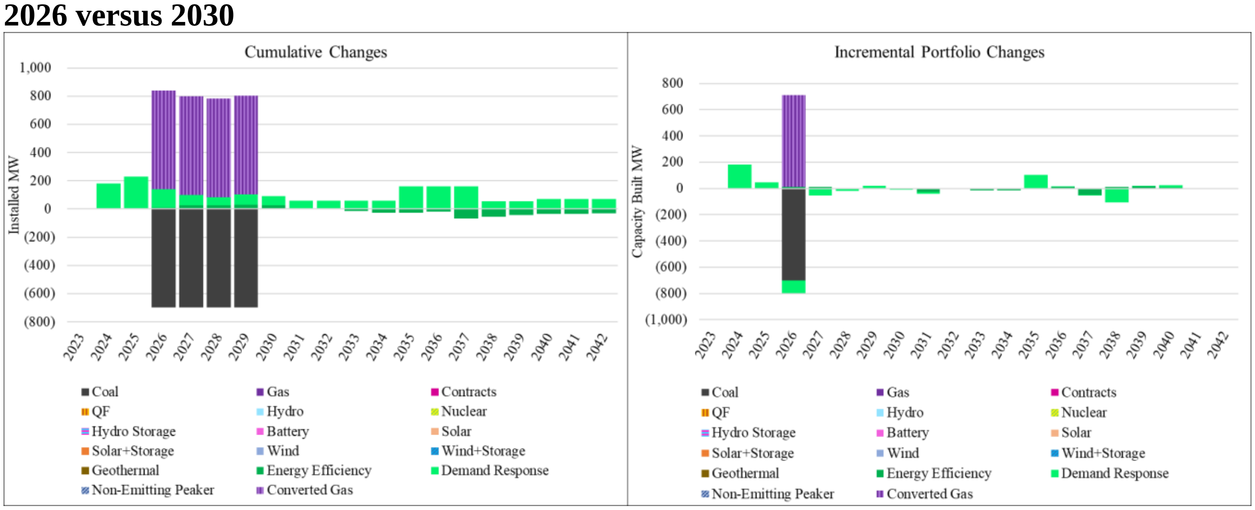
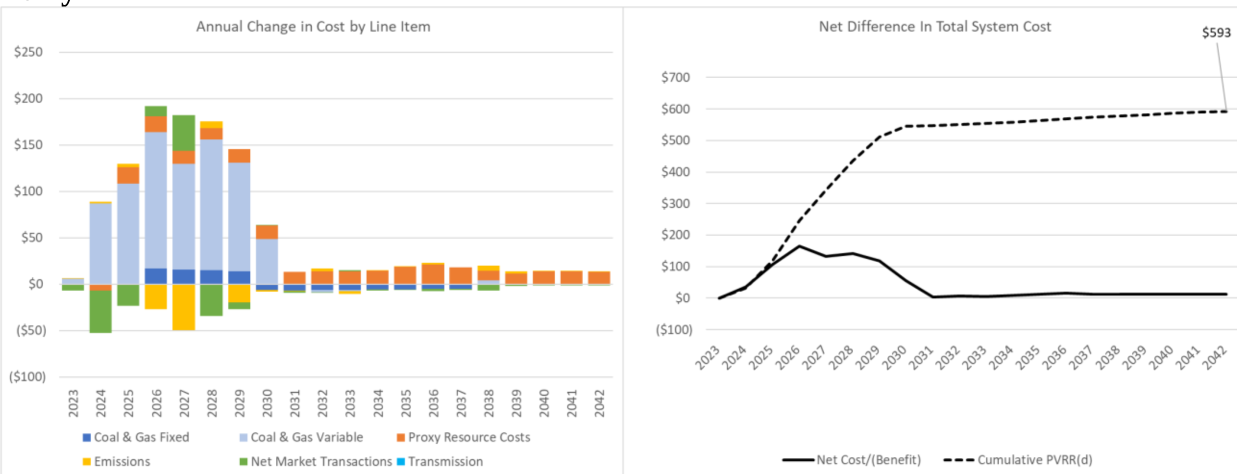


Figure 9.**Figure 9.1 - Increase/(Decrease) in Proxy Resources when Jim Bridger is Gas Converted in 2026 versus 2030**
2 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the timing of the Jim Bridger 3 and 4 Gas Conversion changes. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that converting the units in 2026 is $589 million higher cost than the P-MM Portfolio. On a risk-adjusted basis, which factors

in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio with the early gas conversion of these units is $593 million higher cost than the P-MM portfolio.

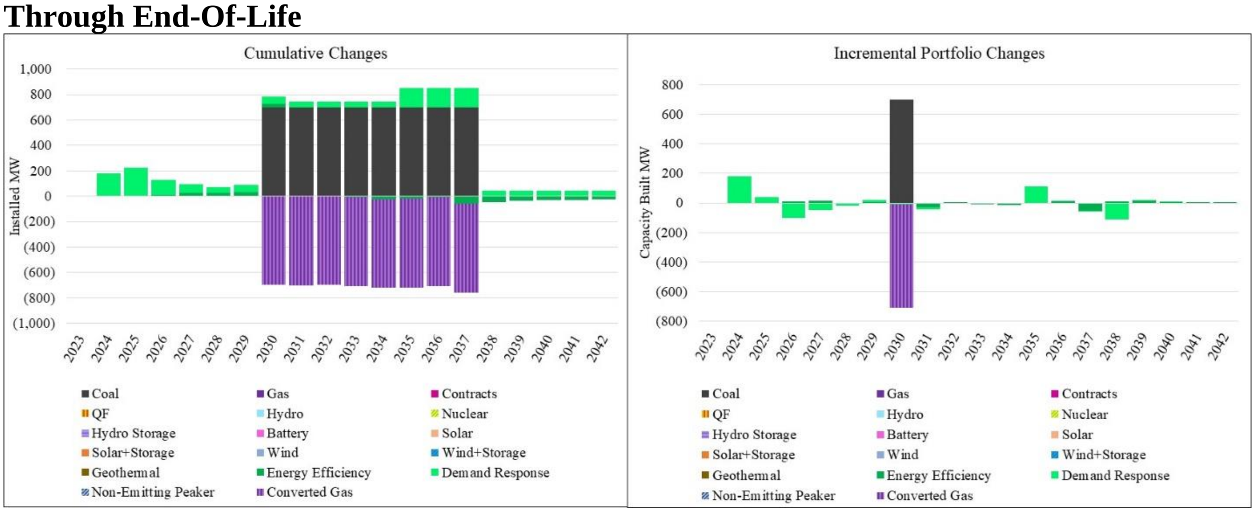
Figure 9.2 Increase/(Decrease) in System Costs when Bridger 3 and 4 Plants Gas Convert Early



Jim Bridger Unit 3 and Unit 4 Remain Coal-Fired through End of Life Variant (P02-JB 3-4 EOL)
The Jim Bridger 3 and 4 Remain Coal-Fired through End of Life variant excludes gas conversion of the Bridger 3 and 4 plants and has them continue operation to their end of life in 2037. This variant explores the potential cost or benefits of keeping these units operating on coal until their end of life, taking into consideration current sunk costs and projected future coal prices.

Figure 9.3 shows the cumulative (at left) and incremental (at right) portfolio changes if these plants continue operating as coal until their end of life at year end 2037 compared to the P1-MM base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. As with the prior variant, Jim Bridger 3 and 4 continue to operate in both scenarios, just with different fuels, so there are only relatively small changes in this portfolio in energy efficiency and demand response.

Figure 9.3 - Increase/(Decrease) in Proxy Resources when Jim Bridger Runs as Coal Through End-Of-Life



Fgure 9.4 Figure 9.4 - Increase/(Decrease) in System Costs when Jim Bridger Runs as Coal Through End-Of-Life

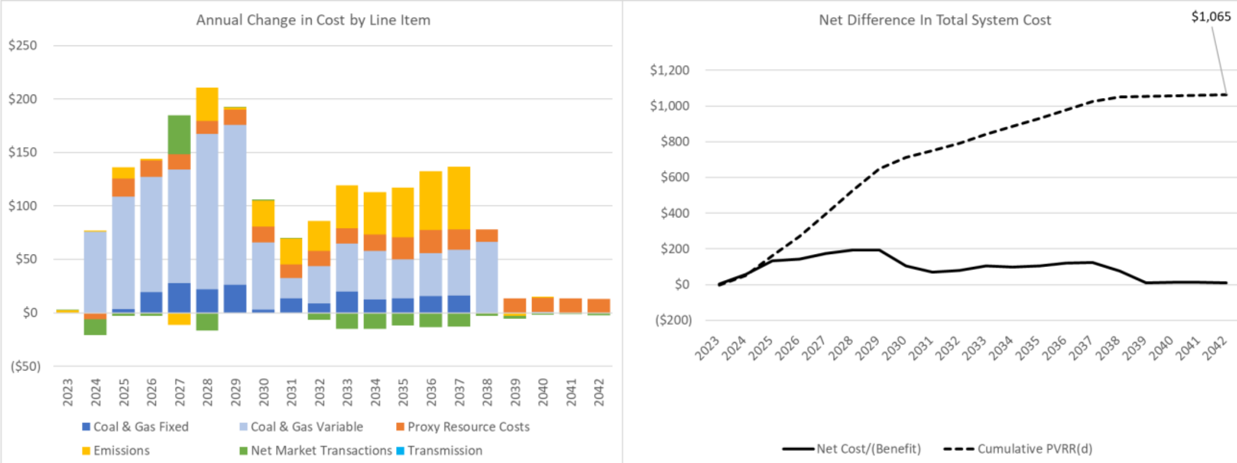
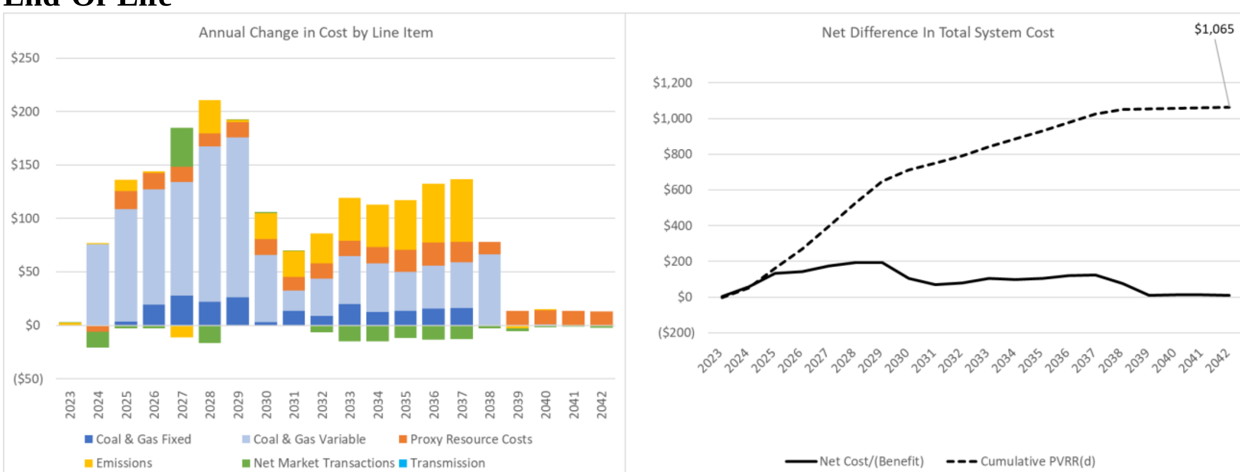


Figure 9.4 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Jim Bridger 3 and 4 Operate as coal through end of life. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that running the Bridger units as coal is $1.07 billion higher cost than the P-MM Portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio running the Bridger units as coal through the end of life is $1.05 billion higher cost than the P-MM portfolio. These costs are primarily driven by higher coal fuel and fixed costs.

Figure 9.4 - Increase/(Decrease) in System Costs when Jim Bridger Runs as Coal Through End-Of-Life



Hunter Unit 3 SCR Installed Instead of SNCR Variant (P03-Hunter SCR)

The Hunter 3 SCR variant evaluates selection of SCR technology over SNCR technology at the Hunter 3 coal unit. This variant also extends the retirement date of the Hunter 3 plant from 2032 through its end of life in 2042. This variant explores the potential impact to emissions compliance and cost or benefits of utilizing a different emissions mitigation technology to this unit.

Figure 9.5 shows the cumulative (at left) and incremental (at right) portfolio changes if the Hunter 3 plant continues operating until its end of life with an SCR compared to the P-MM base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. In this case, the inclusion of Hunter 3 with an SCR causes a reduction in solar which is sited at the Hunter locations as a surplus resource. Given the implications of OTR compliance, there are no other resource reductions in this case, as coal operations are limited during high need times in the summer, and firm, non-emitting resources are still needed. The balance of the changes in this portfolio are related to energy efficiency and demand response.

Figure 9.5 - Increase/(Decrease) in Proxy Resources when Hunter 3 runs as SCR Through its End-of-Life

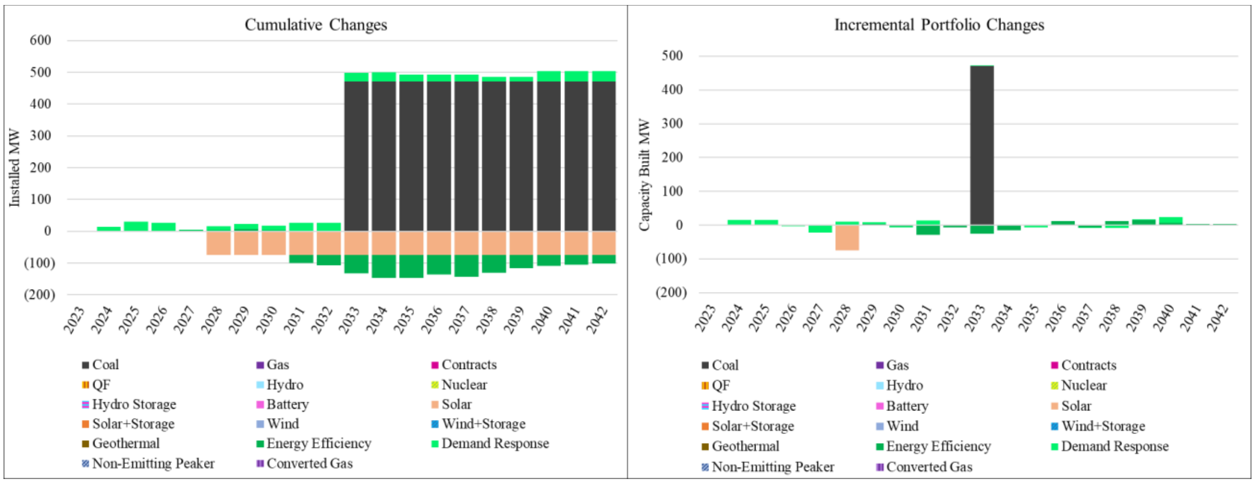
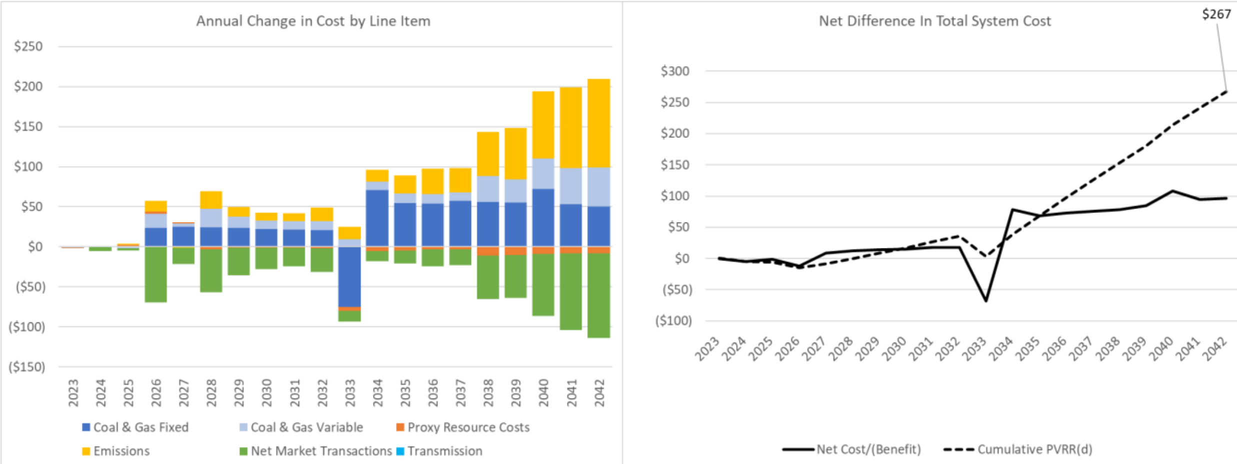


Figure 9.6 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Hunter 3 operates as coal with an SCR through end of life. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that running Hunter 3 as coal with SCR is $257 million higher cost than the P-MM Portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio running the Hunter 3 with SCR through the end of life is $267 million higher cost than the P-MM portfolio. The lower market reliance costs in this case are fully offset by coal fuel and emissions costs.

Figure 9.6 - Increase/(Decrease) in System Costs when Hunter 3 runs as SCR Through its End-of-Life



Huntington Unit 1 Early Retirement in 2028 Variant (P04-Huntington RET28)

The Huntington 1 Early Retirement variant evaluates shifting the date of the Huntington 1 plant retirement from the end of 2032 to the end of 2028. This variant explores the potential impact to the system of removing firm capacity early in the study and replacing this with non-emitting technology. This study seeks to identify potential risks from closing this coal plant earlier than in the P-MM portfolio.

Figure 9.7 shows the cumulative (at left) and incremental (at right) portfolio changes if the Huntingotn 1 plant were to cease operations at the end of 2028 compared to the P-MM base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. In this case, the earlier retirement of the Huntington 1 plant prompts the acceleration of 400 MW of storage from 2033 and 2037 into 2028. Additionally, the acceleration is limited to four hour storage versus the inclusion of some long duration storage. High surplus builds at the hunter and Huntington sites through 2032 mean storage is the needed solution versus additional generating resources. The balance of the changes in this portfolio are related to energy efficiency and demand response.

Figure 9.7 - Increase/(Decrease) in Proxy Resources when Huntington 1 Retires End of 2028

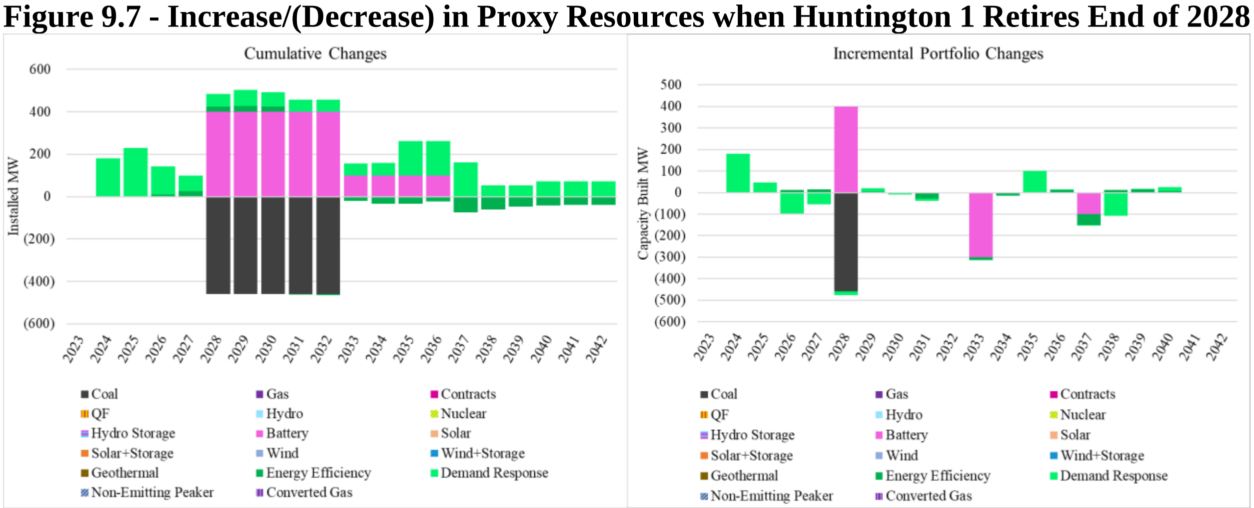
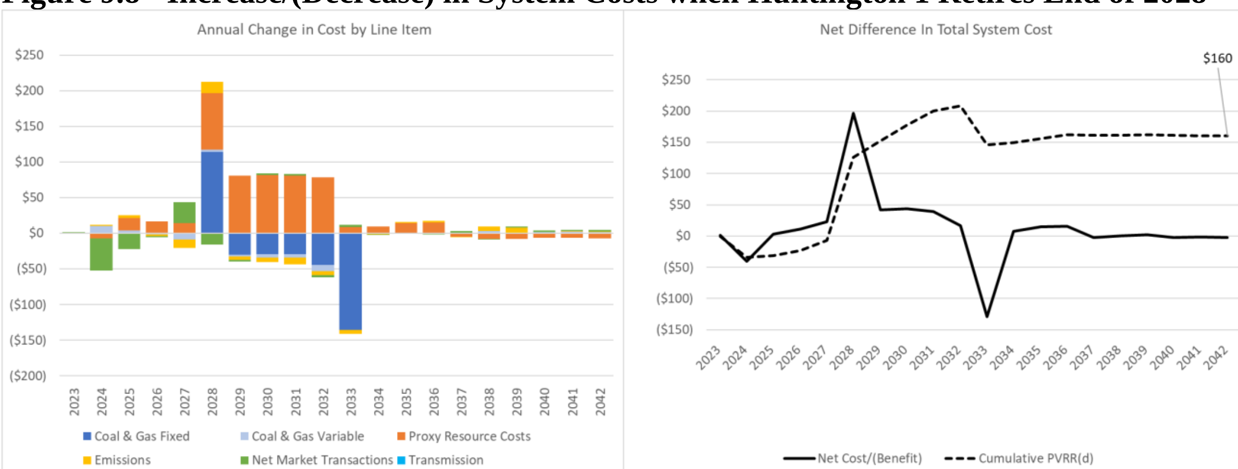


Figure 9.8 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Huntington 1 retires at the end of 2028. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that retiring Huntington 1 early at the end of 2028 is $160 million higher cost than the P-MM Portfolio. These two portfolios had a risk adjustment that, when added to the total PVRR, rounded to the same figure, so on a risk-adjusted basis, the PVRR(d) remains a $160 million higher cost than the P-MM portfolio. The early retirement of Huntington 1 has lower fixed coal costs and lower emissions. This figure is offset by the higher proxy capital costs caused by accelerating builds into the highest part of the supply side cost curve.

Figure 9.8 - Increase/(Decrease) in System Costs when Huntington 1 Retires End of 2028



Nuclear Selections Replaced with Non-Emitting Peakers Variant (P05-No NUC)

The P05-No Nuc portfolio is a variant of the P1-MM portfolio that eliminates the Natrium™ advanced nuclear demonstration project and any future nuclear projects. When this variant is compared to the PA1-MM portfolio, changes in proxy resources and system costs driven by the removal of nuclear projects can be isolated.

Figure 9.9 shows the cumulative (at left) and incremental (at right) portfolio changes when all nuclear projects are eliminated from the P1-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. Without the Natrium™ demonstration project, 289 MW of non-emitting peaking resource is added to the portfolio in 2030. Gas plants at the Naughton site were assumed to continue operation to backfill the Natrium project during any outages, and in a no Natrium scenario are relied upon more heavily. In 2032 303 MW of non-emitting peaking resource and 200 MW of battery storage are added at Hunter in replacement of the advanced nuclear plant in P-MM. This selection is duplicated in 2033. The balance of changes in the portfolio are demand response and energy efficiency related.

Figure 9.9 – Increase/(Decrease) in Proxy Resources when Nuclear Projects are Eliminated from the P1-MM portfolio.

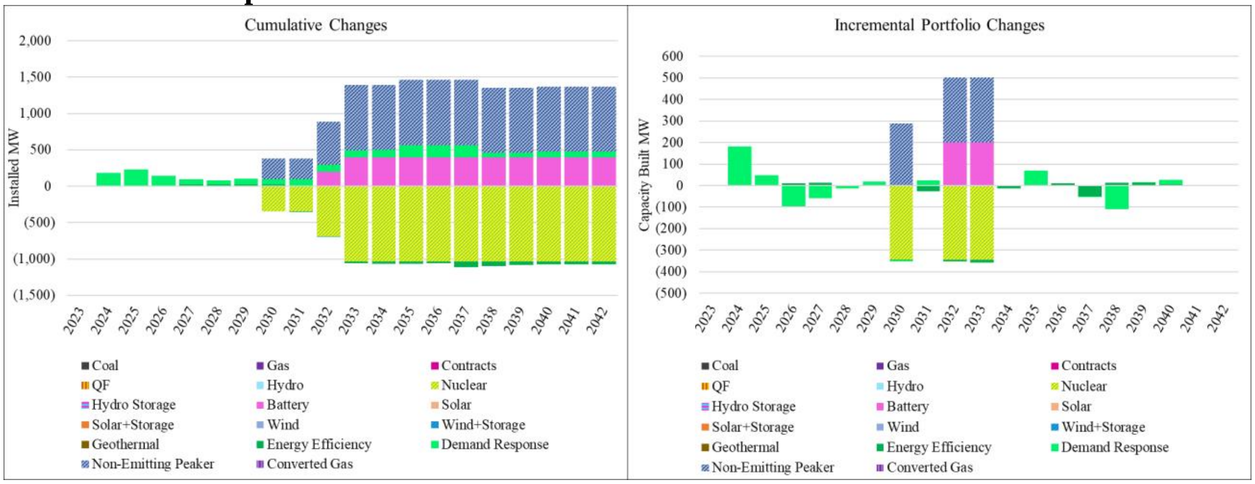
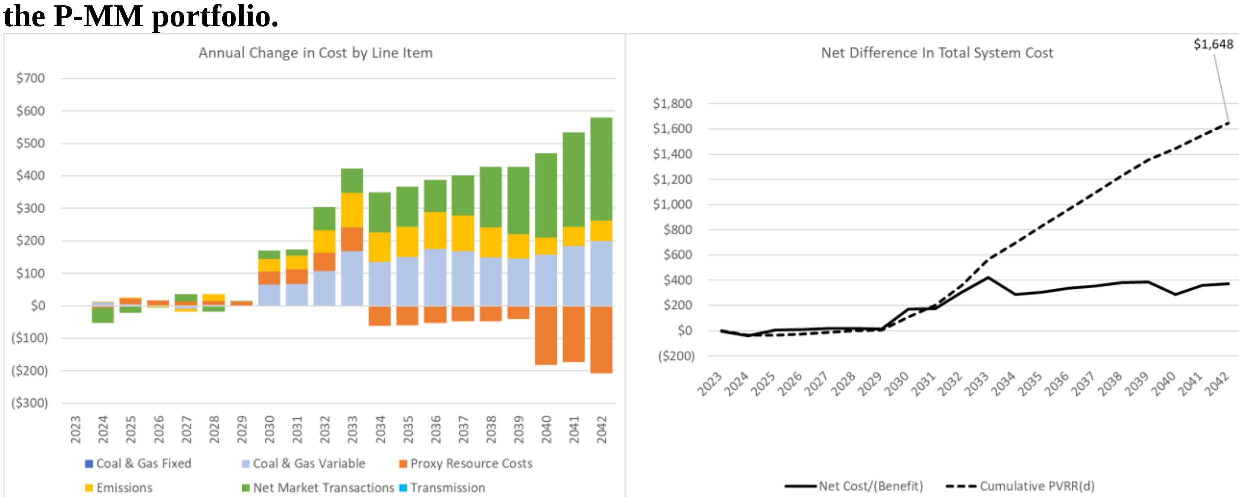


Figure 9.10 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the Natrium™ demonstration project and other nuclear projects are eliminated from the P1-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio without nuclear projects is $1.65 billion higher cost than the P1-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without nuclear resources is $1.90 million higher cost than the P-MM portfolio.

When the advanced nuclear projects are removed from the portfolio, the cost for new proxy resources decreases overall as the replacement options have lower capital costs. However, higher ongoing variable and fuel costs at peaking resources, and higher emissions costs more than offsets any reduced capital savings garnered by eliminating nuclear plants from the portfolio.

Figure 9.10 Increase/(Decrease) in System Costs when Nuclear Projects are Eliminated from the P-MM portfolio.



Nuclear and Non-Emitting Peakers Replaced with Non-Gas Options Variant (P06-No Forward Tech)

The P06-No Forward Tech portfolio is a variant of the P1-MM portfolio that eliminates all future resource options which are not currently available within the existing PacifiCorp portfolio. When this variant is compared to the P1-MM portfolio, changes in proxy resources and system costs driven by the removal of all future technology types can be isolated.

Figure 9.11 shows the cumulative (at left) and incremental (at right) portfolio changes when all future technology projects are eliminated from the P1-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. Without any future technology, long duration storage and four hour battery stoage are added at Hunter and Huntington in 2032 and 2033 respectively. These sites also house large surplus solar builds meaning that the addition of a mix of long duration and four hour battery for reliability is sufficient. Gas plants at the Naughton site were assumed to continue operation until the end of life, being replaced by 600 MW of solar resources in 2037. The balance of changes in the portfolio are demand response and energy efficiency related.

Figure 9.11 – Increase/(Decrease) in Proxy Resources when all Future Technology is Eliminated from the P1-MM Portfolio.

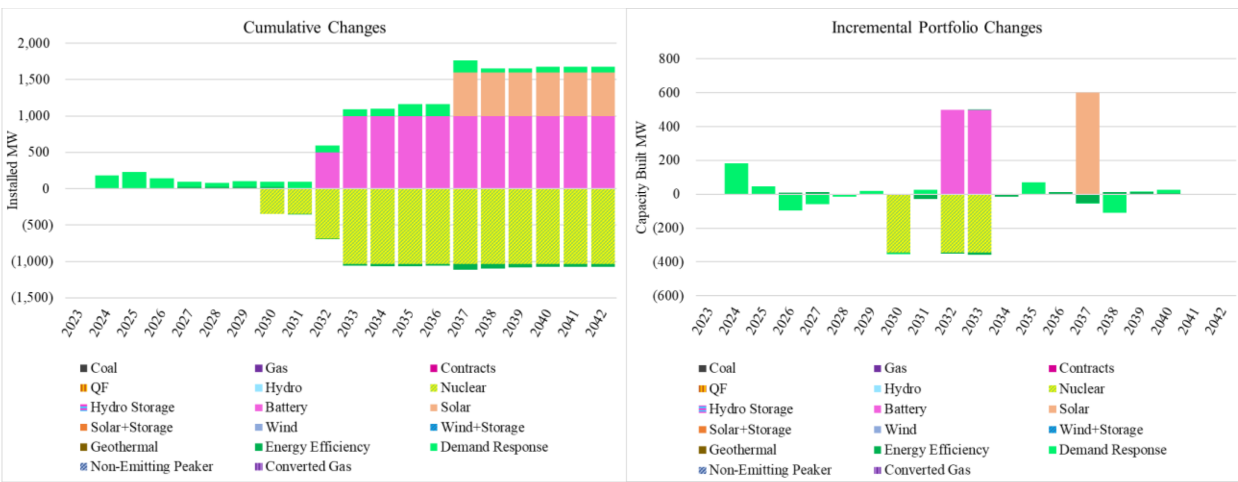
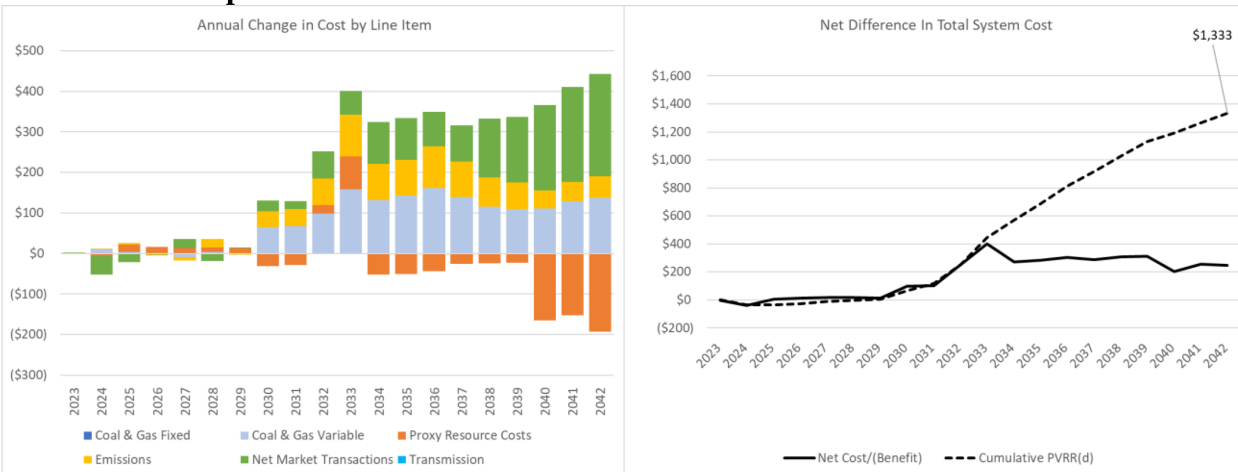


Figure 9.12 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when all future technology is eliminated from the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio without future technology is $1.34 billion higher cost than the P1-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without future technology is $1.57 billion higher cost than the P-MM portfolio.

When the future technology project is removed from the portfolio, new proxy FOM and capital costs decrease overall. However, significantly higher fuel and emissions costs, plus greater reliance on markets to maintain reliability more than offsets any savings garnered by eliminating the generally higher upfront costs of future technology from the portfolio.

Figure 9.12 – Increase/(Decrease) in System Costs when Future Technology is Eliminated from the P-MM portfolio.



D3 and D2.2 Transmission Delayed Until 2032 Variant (P07-D3 32)

The P07-D3 32 portfolio is a variant of the P-MM portfolio that evaluates the impact a delay in the timing of D2.2 and D3 has on the portfolio. When this variant is compared to the P-MM portfolio, changes in proxy resources and system costs driven by the delay in both transmission and resource selection can be isolated.

Figure 9.13 shows the cumulative (at left) and incremental (at right) portfolio changes when the D2.2 and D3 transmission projects are delayed to 2032. 600 MW of storage is shifted from 2035 into 2025 in this case in order to meet reliability needs in the interval where D2.2 and D3 are not built. Additional battery is built in 2027, and wind projects are delayed from 2029 to 2032. This portfolio selects a total of 1,337 MW of additional wind when compared to the P-MM study. Wind selections are grouped all into 2032 and 2033 due to the timing of the transmission projects.

Figure 9.13 - Increase/(Decrease) in Proxy Resources when D2.2 and D3 are delayed to 2032

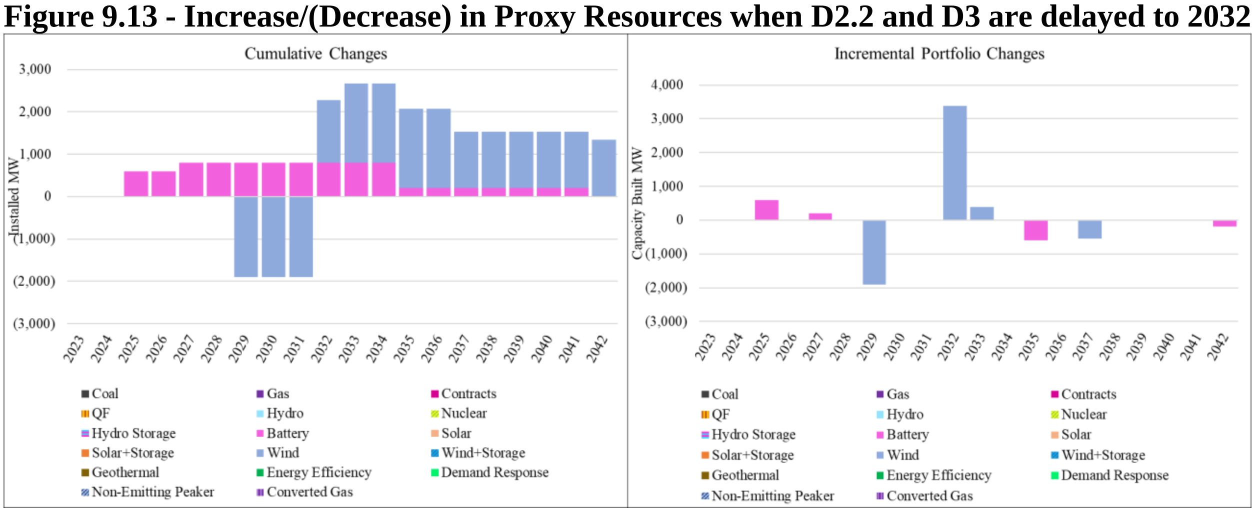
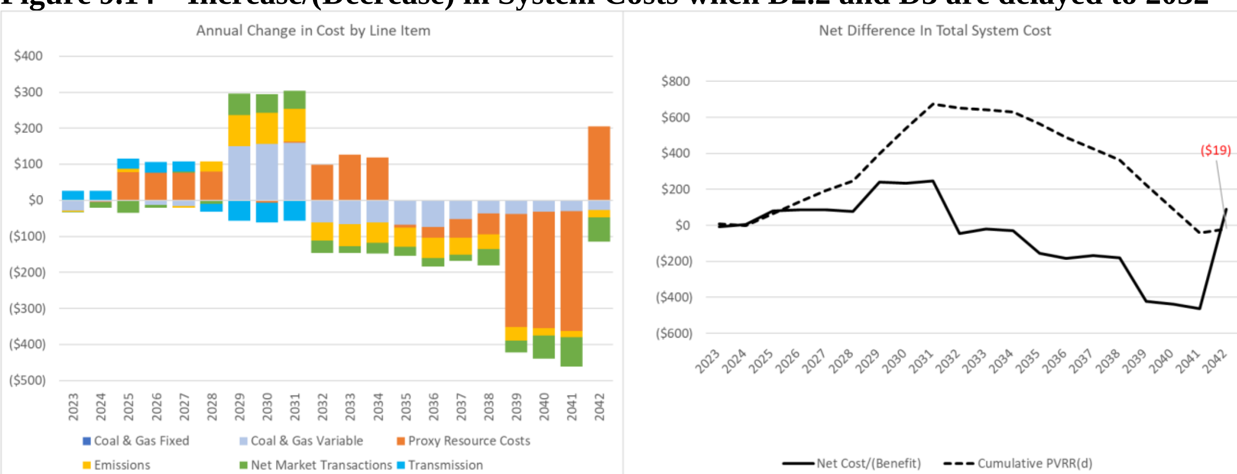


Figure 9.14 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the transmission selection changes from the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system

costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio delaying D2.2 and D3 is $19 million lower cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio delaying D2.2 and D3 is $70 million lower cost than the P-MM portfolio. Much of the cost differential is a result of the Company's forecast of significant declines in wind resource build costs between 2029 and 2032. Because the potential benefits are largely based on cost declines which may occur earlier or not at all, rather than the specific operating characteristics of these portfolios, it is appropriate to look for opportunities to procure lower cost resources on an earlier timeframe.

Higher total proxy resource costs as a result of a larger resource build are offset in this case by lower emissions and less reliance on the market. Having a larger amount of wind in the portfolio is also a benefit to the case delaying D2.2 and D3 as this portfolio has higher late PTC levels than P-MM. The D2.2 and D3 delay case also has higher early reliance on energy storage, which may or may not be feasible. Additionally, interconnection or transmission service requests could trigger a portion of these transmission upgrades earlier than 2032, which is not wholly in the control of the Company.

Figure 9.14 – Increase/(Decrease) in System Costs when D2.2 and D3 are delayed to 2032



Excluded Selection of D3 and D2.2 Transmission Variant (P08-No D3-D2)

The P08-No D2-D3 portfolio is a variant of the P-MM portfolio that evaluates the impact excluding D2.2 and D3 from selection has on the portfolio. When this variant is compared to the P-MM portfolio, changes in proxy resources and system costs driven by the elimination of these transmission lines and the impact to renewable resources which rely on these lines lines can be evaluated.

Figure 9.15 shows the cumulative (at left) and incremental (at right) portfolio changes when the D2.2 and D3 transmission projects are eliminated from the portfolio. 1,900 MW of wind is no longer eligible to come online in 2029 and is removed from the portfolio. An additional removal of 435 MW of wind in 2032 is offset by 1,400 MW of storage, 600 MW of which is long duration storage. In 2037, another 540 MW of wind is removed from the portfolio. 1,000 MW of advanced nuclear plants are sited at existing coal sites to offset the Wyoming wind which was no longer eligible for selection in the absence of the increased interconnection capability associated with these transmission projects.

Figure 9.15 - Increase/(Decrease) in Proxy Resources when D2.2 and D3 are Excluded

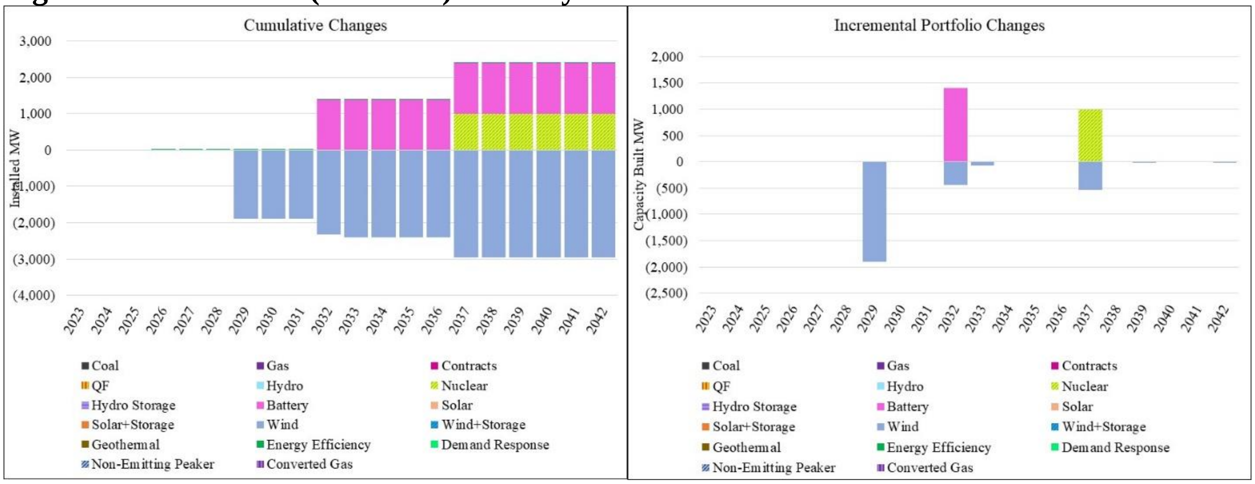
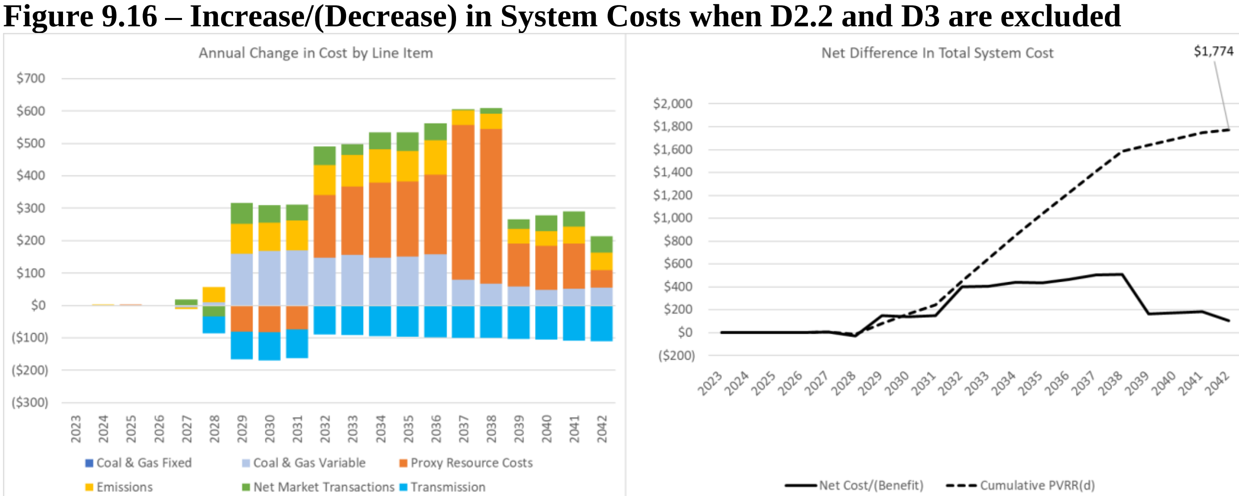


Figure 9.16 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the D2.2 and D3 are excluded from the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio excluding D2.2 and D3 is $1.77 billion higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio excluding D2.2 and D3 is $1.92 billion higher cost than the P-MM portfolio.

The significant reduction in early proxy capital costs and transmission costs is overtaken by higher fuel costs (both coal and gas), as well as significant emissions costs. Additionally, the loss of Production Tax Credit generating renewable resources results in much higher overall renewables variable costs in the study which excludes D2.2 and D3. Finally, an increased reliance on the market also contributes to higher overall costs in this case.

Figure 9.16 – Increase/(Decrease) in System Costs when D2.2 and D3 are excluded

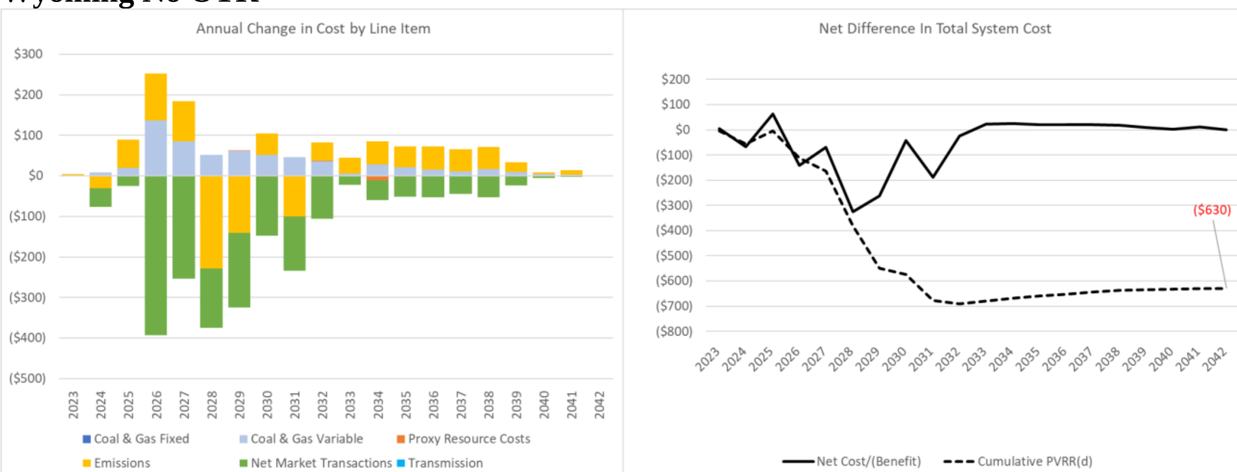


Assume Wyoming is not Subject to OTR Variant (P09-No WY OTR)

This variant does not change resource selections from that assumed in the preferred portfolio, but instead removes the federal Ozone Transport Rule (OTR) compliance obligation for thermal resources located in the state of Wyoming.

Figure 9.17 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when OTR considerations are eliminated from the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio operation without Wyoming OTR restrictions is $630 million lower cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, system dispatch without Wyoming OTR compliance obligations is $673 million lower cost than the P1-MM portfolio.

Figure 9.17 – Increase/(Decrease) in System Costs of P-MM Portfolio Operating Under Wyoming No OTR



Inclusion of Offshore Wind Project Variant (P10-Offshore Wind)

The P10-Offshore Wind portfolio is a variant of the P-MM portfolio that forces in a minimum of 1000 MW of offshore wind in southern Oregon. As offshore wind was not selected in any initial portfolio runs, regardless of price variant, this study seeks to evaluate whether offshore wind would be a cost or benefit to the system. P-MM does select resources in southern Oregon which necessitate the transmission option that enables offshore wind, so the variations in this study are all generator specific and not impacted by transmission choices.

Figure 9.18 shows the cumulative (at left) and incremental (at right) portfolio changes when offshore wind is selected in the P-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. With offshore wind added to the portfolio there is a one year delay of 100 MW of wind in southern Oregon. This delay consolidates the P-MM southern Oregon wind build from two years into one year, once the transmission project which enables offshore wind comes online. The southern Oregon non-emitting peaking resource which was selected in P-MM is replaced by 300 MW of 4 hour battery in 2037.

Figure 9.18 – Increase/(Decrease) in Proxy Resources when Offshore Wind is Added to the P-MM Portfolio.

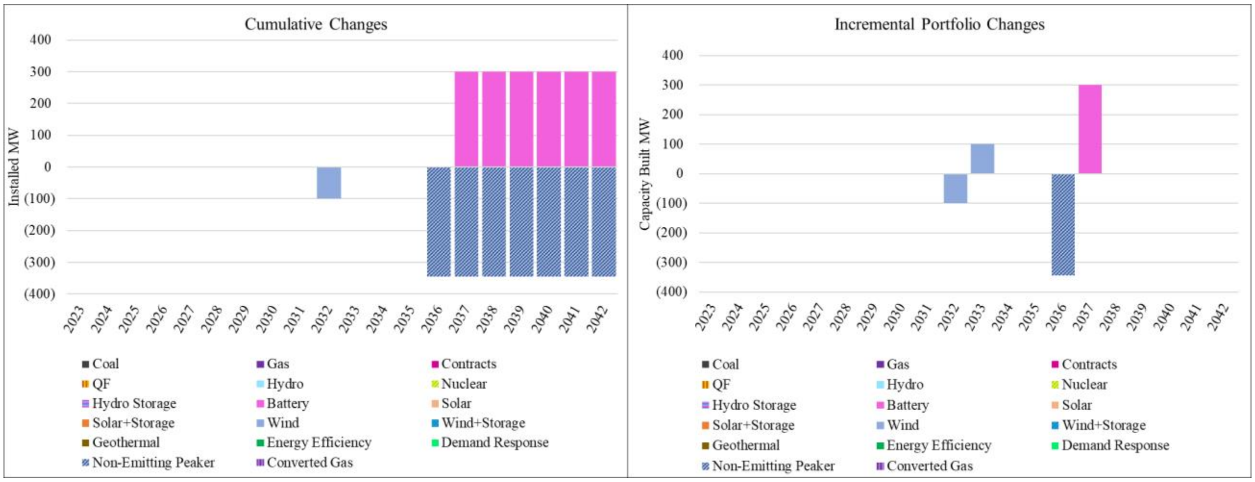
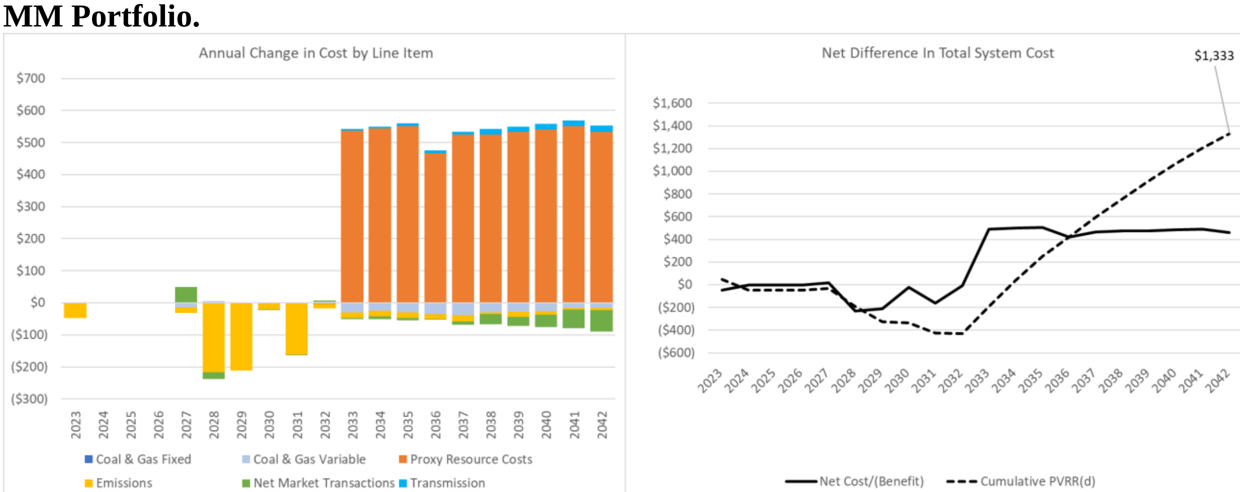


Figure 9.19 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when all future technology is eliminated from the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio without future technology is $1.34 billion higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the demonstration project is $1.71 billion higher cost than the P-MM portfolio.

When offshore wind is added to the portfolio, new proxy FOM and capital costs decrease overall. However, significantlyhigher fueland emissions costs, plus greater reliance on markets to maintain reliability more than offsets any savings garnered by eliminating the generally higher upfront costs of future technology from the portfolio.

Figure 9.19 – Increase/(Decrease) in System Costs when Offshore Wind is Added to the P-MM Portfolio.



Nuclear and Non-Emitting Peakers Replaced with Natural Gas Variant (P11-Max NG)

The P11-Max NG Variant portfolio is a variant of the P-MM portfolio that assumes natural gas peaking resources are the only option to replace coal capacity as it retires. The cost to build pipelines to all current coal sites may be prohibitive, so in cases where that cost is too great, alternative sites for natural gas fueled generators were considered. When this variant is compared to the P-MM portfolio, changes in proxy resources and system costs driven by the exclusive use of natural gas fueled replacement resources can be isolated.

Figure 9.20 shows the cumulative (at left) and incremental (at right) portfolio changes natural gas fueled generators replace coal generation in the P-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. Limiting the model from selecting future technology and replacing those options with natural gas fueled resources result in the removal of 1500 MW of advanced nuclear plants in 2030, 2032 and 2033, and non-emitting peaking resources in 2030. 303 MW of the non-emitting peaking resource is not eligible to be replaced in the portfolio by natural gas fueled items as it was built in Oregon which does not allow for natural gas fueled generation in 2030. These removals of nuclear and non-emitting peaking resources are replaced by 1,044 MW of natural gas combined cycle plants in 2032. An additional 500 MW of combined cycle plants is built in 2037 and another 522 MW in 2040. Duct firing technology is added to the 500 MW units built in 2037 bringing total natural gas fueled additions to 2,349 MW during the study versus nuclear and non-emitting peaking removals of 2,740 MW.

Figure 9.20 – Increase/(Decrease) in Proxy Resources when Gas Replaces Future Technology in the P-MM Portfolio.

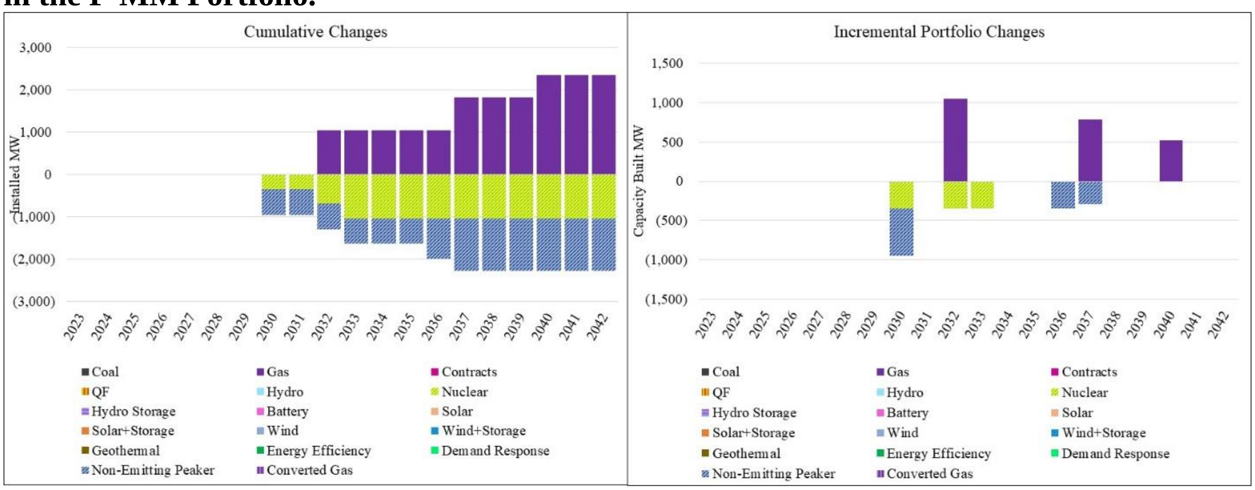
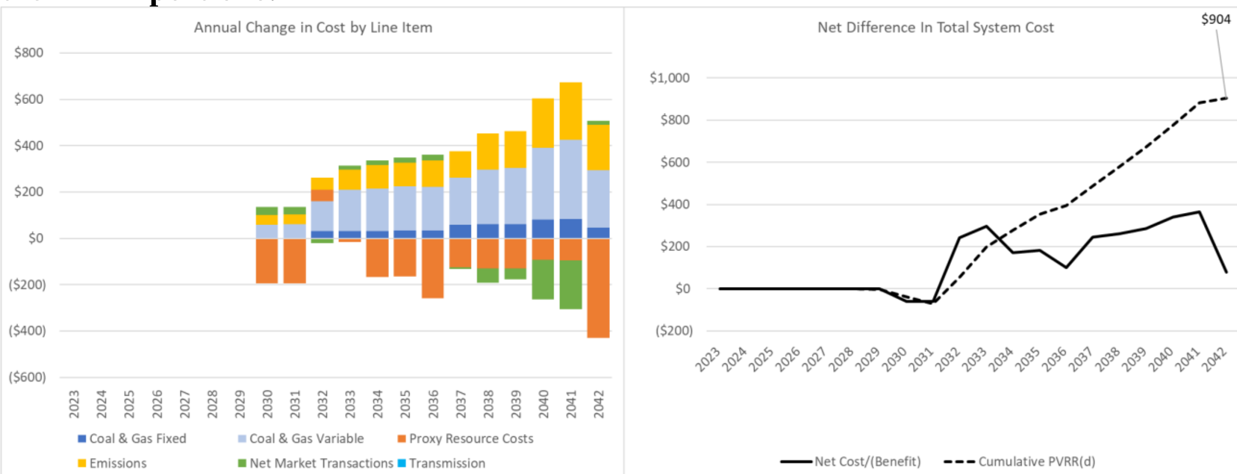


Figure 9.21 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when gas replaces all future technology in the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio which replaces future technology with gas fueled generation is $904 million higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio wich replaces future technology with gas fueled generation is $1,161 million higher cost than the P1-MM portfolio.

Lower future proxy fixed costs are the result of lower capital and fixed costs on gas fueled units. These lower costs are offset by much higher variable and fuel costs, as well as significantly higher emissions costs.

Figure 9.21 – Increase/(Decrease) in System Costs when Gas Replaces Future Technology in the P-MM portfolio.



Retire All Coal by Year-End 2029; Retire All Natural Gas by Year-End 2039 Variant (P12-RET Coal 30 NG 40)

The P12- Retire Coal by end of 2029, Retire Gas by end of 2039 Variant portfolio is a variant of the P-MM portfolio that evaluates potential costs and benefits to the system in a scenario where all coal is retired by the end of 2029 and all gas is retired by the end of 2039. When this variant is compared to the P-MM portfolio, changes in proxy resource selections and system costs driven by early retirements of all fossil fueled resources can be isolated.

Figure 9.22 shows the cumulative (at left) and incremental (at right) portfolio changes when coal is retired no later than the end of 2029 and gas is retired no later than the end of 2039. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. For coal plants where natural gas conversion is an option, natural gas conversion is the selection made by the model. Due to the high level of coal sited surplus renewables, generators in this case are replaced towards the end of life with non-emitting peaking resources. In 2037, 1501 MW of non-emitting peaking resources are selected by the model, along with 136 MW of wind. 623 MW of additional stand alone storage was added to the east side of the system and 500 MW of stand alone storage was added to the west side in 2037 as well.

9.22 - Increase/(Decrease) in Proxy Resources when Coal is retired by the end of 2029 and gas is retired by the end of 2039 in the P-MM Portfolio

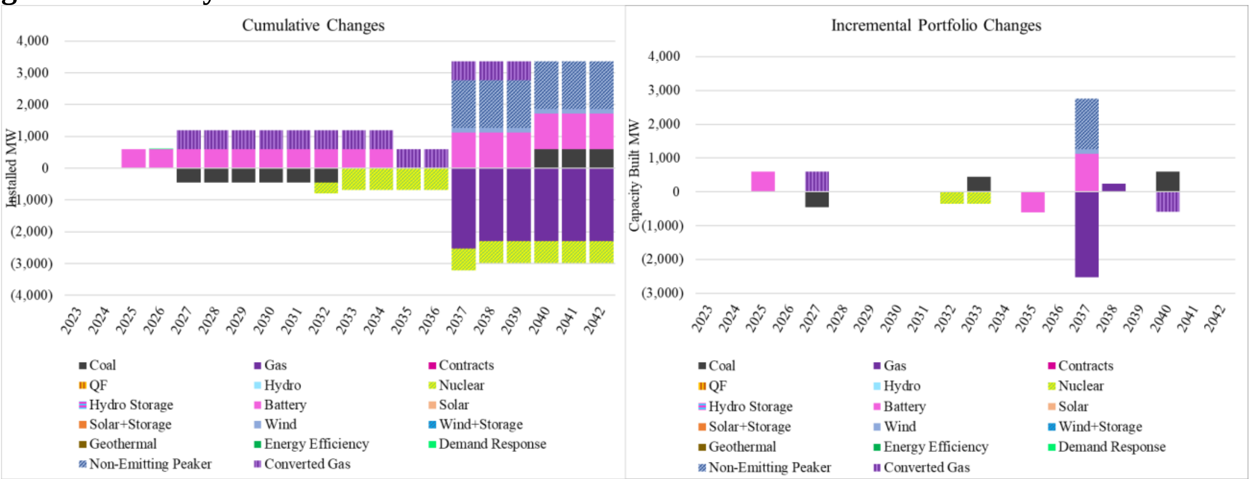
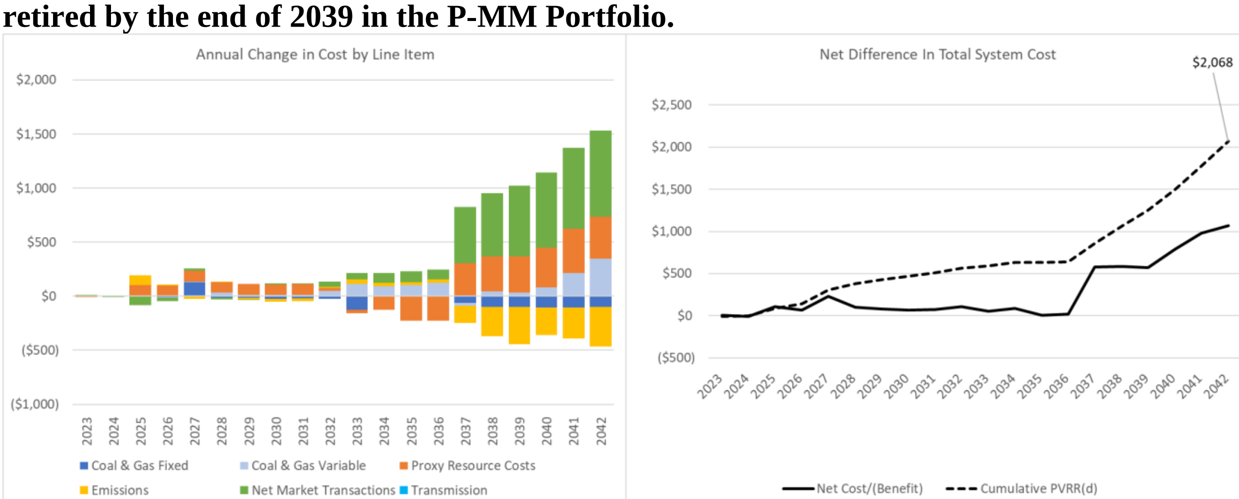


Figure 9.23 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when coal is retired by 2029 and gas is retired by 2039 gas replaces all future technology in the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the early retirement portfolio is which replaces future technology with gas fueled generation is $2.068 billion higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the early retirement portfolio is portfolio wich replaces future technology with gas fueled generation is $2.27 billion higher cost than the P-MM portfolio.

These cost changes are driven by variable cost differences. There is much higher market reliance without natural gas and coal fueled generation. Additionally, although coal and gas are retired, the need to keep firm resources on the system through gas conversion of 2 coal units leads to higher gas fuel costs.

9.23 - Increase/(Decrease) in System Costs when Coal is retired by the end of 2029 and gas is retired by the end of 2039 in the P-MM Portfolio.



All DSM Programs Variant (P13-All DSM)

The Include all DSM variant forces the model to select all demand response and energy efficiency available in addition to what is selected in the P-MM portfolio. This scenario does not change any other resource selections, but does seek to define dispatch, emissions and costs if all DSM programs are implemented. The changes to DSM selections are summarized in Figure 9.24. By the end of the study 3,128 MW of energy efficiency and 871 MW of demand response are selected.

Figure 9.24 - Increase/(Decrease) in Proxy Resources when all DSM programs are selected in P-MM Variant (P13-All DSM)

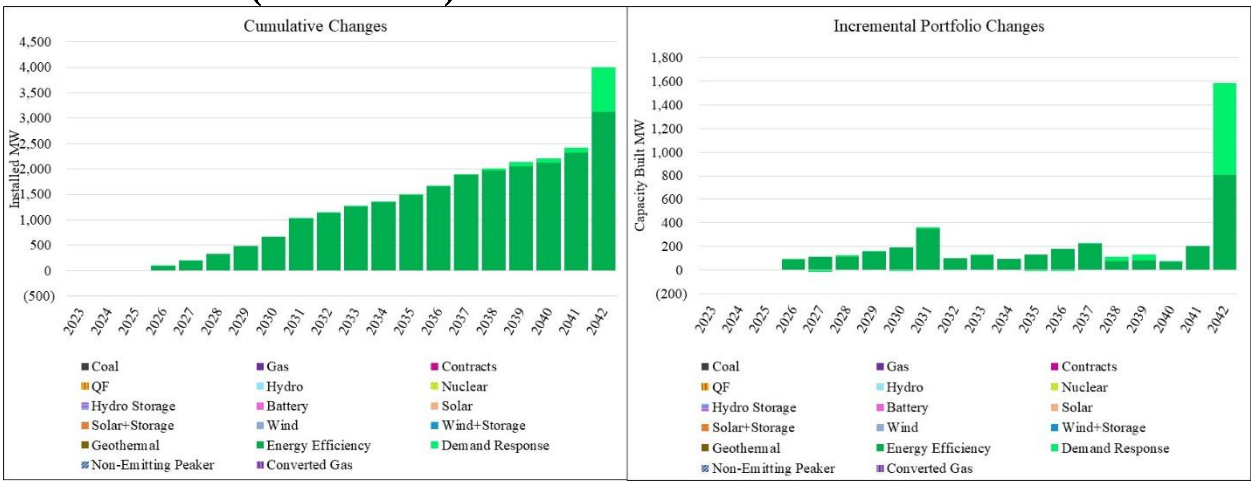
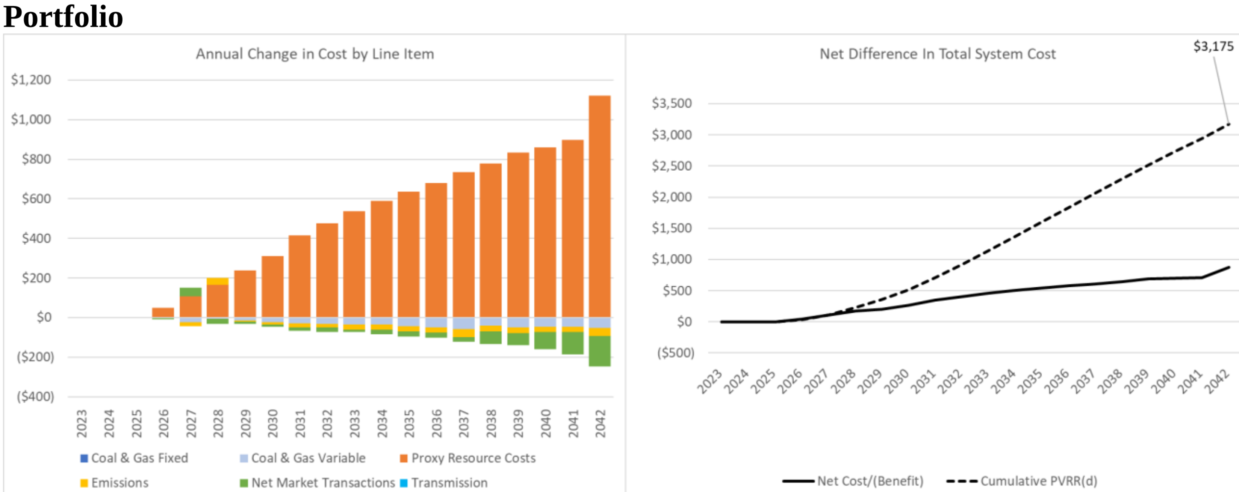


Figure 9.25 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when all DSM is selected in the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that adding all DSM is $3,175 million higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio that adds all DSM is $3,143 million higher cost than the P-MM portfolio. Coal and gas fuel cost reductions, reduced reliance on the market and lower emissions costs are offset beginning in 2027 by the much higher DSM costs.

Figure 9.25 – Increase/(Decrease) in System Costs of including all DSM in the P-MM Portfolio

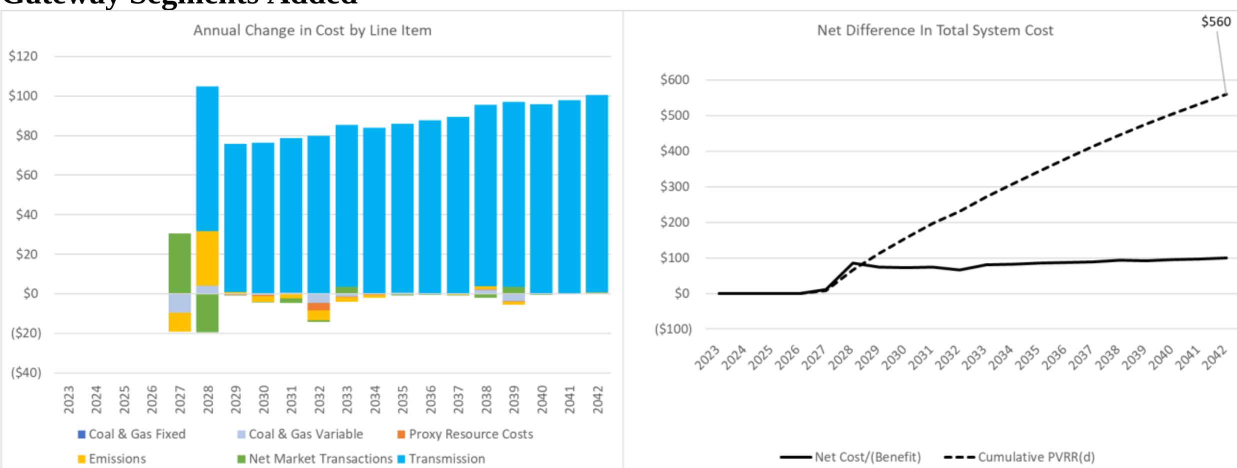


Inclusion of All Energy Gateway Transmission Options Variant (P14-All GW)

The Include All Energy Gateway Transmission Options Variants adds in Segment E, which is the only portion of the Energy Gateway Transmission project which was not selected by the model. As this specific portion of the Energy Gateway project does not enable new resource interconnection, this variant seeks to evaluate whether the increased flexibility to the transmission system provided by Segment E is a cost or benefit to the system. There is no portfolio difference to show in this scenario as resource selections are assumed not to be impacted by this addition.

Figure 9.26 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Segment E is included in the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the addition of Segment E is $560 million higher cost than the P-MM portfolio. The risk adjustments for the two portfolios ended up rounding to the same number, so on a risk-adjusted basis the All Gateway variant remains $560 million higher cost than the P-MM portfolio, with the entirety of the difference made up of increased transmission costs.

Figure 9.26 – Increase/(Decrease) in System Costs of P-MM Portfolio with All Energy Gateway Segments Added



Exclusion of Energy Gateway South Variant (P15-No GWS)

The P15-No GWS portfolio is a variant of the P1-MM portfolio that eliminates the GWS, D.1, D2.2 and D3 transmission lines as these lines are reliant on each other to be built. Because wind bids from the 2020AS RFP and future proxy resources that are located in eastern Wyoming cannot interconnect without these transmission lines, these resources are also eliminated from the P15-No GWS portfolio. When this variant is compared to the P1-MM portfolio, changes in proxy resources and system costs driven by the removal of GWS and associated transmission lines can be isolated.

Figure 9.27 shows the cumulative (at left) and incremental (at right) portfolio changes when these transmission lines are eliminated from the P1-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the transmission lines are eliminated. Without GWS and D.1, 2020AS RFP wind resources are removed from the portfolio in 2024 (shown as a reduction in 2025, the first full year these resources would be online). An additional 289 MW of wind is eliminated in 2030. In 2034, the absence of the new wind resources triggers the addition of an additional advanced nuclear plant that displaces solar co-located with storage resources. The lack of resource additions with the removal of wind resources in the portfolio without GWS and D.1 signals an increase in market reliance.

Figure 9.27 – Increase/(Decrease) in Proxy Resources when the GWS and D.1 Transmission Lines are Eliminated from the P-MM portfolio.

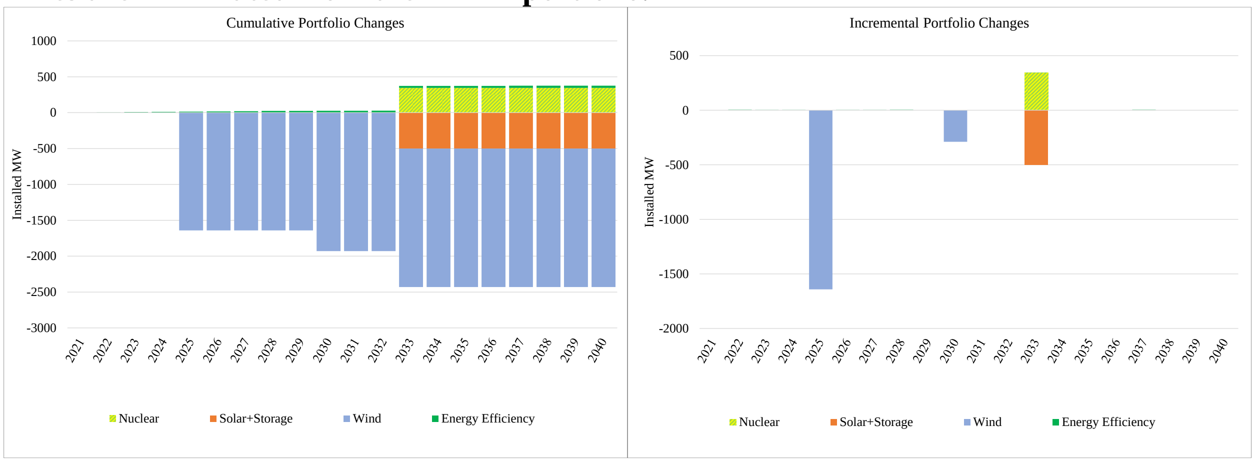
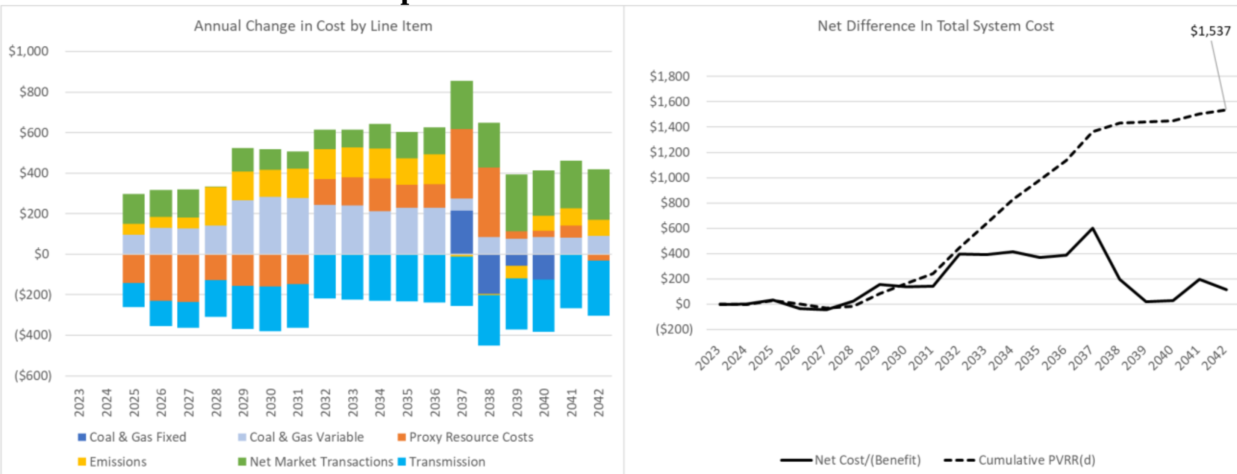


Figure 9.28 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the GWS and associated transmission lines are eliminated from the P1-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio without the GWS and D.1 transmission lines is $1,537 million higher cost than the P1-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the GWS and associated transmission lines is $1,822 million higher cost than the P1-MM portfolio. The risk-adjusted results indicate that the GWS and D.1 transmission lines add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

Lower transmission and proxy fixed costs are far outweighed by much higher emission costs and variable operating costs across the portfolio. There is a much higher reliance on markets without GWS and associated transmission lines, and the portfolio has much greater exposure to coal and gas fuel prices.

Figure 9.28 – Increase/(Decrease) in System Costs when the GWS Transmission Lines are Eliminated from the P1-MM portfolio.



Exclusion of the Selection of B2H Transmission Variant (P16-No B2H)

The P16-No B2H portfolio is a variant of the P-MM portfolio that eliminates the B2H transmission line. When this variant is compared to the P-MM portfolio, changes in proxy resources and system costs driven by the removal of the B2H transmission line can be isolated.

Figure 9.29 shows the cumulative (at left) and incremental (at right) portfolio changes when the B2H transmission line is eliminated from the P-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the transmission line is eliminated. Without B2H, 300 MW of wind and 400 MW of solar co-located with 600 MW of storage is removed from the portfolio at Borah in 2028. 725 MW of eight-hour duration battery is added to the portfolio in 2027 as a requirement in Southern Oregon in the absence of B2H, however this battery is held available to increase the reliability of deliveries to Central Oregon loads, so it is not dispatched under the normal system conditions represented in the Plexos model. The resources removed from Borah are shifted to Southern Oregon and Walla, with 600 MW of battery added to those locations in 2028, an acceleration of 400 MW of wind from 2033 into 2030, and an additional 1000 MW of solar and 600 MW of storage added in Southern Oregon in 2033. Without incremental access to PacifiCorp East resources in the absence of B2H, significantly more resources are required in Oregon.

Figure 9.29 – Increase/(Decrease) in Proxy Resources when the B2H Transmission Line is Eliminated from the P-MM portfolio.

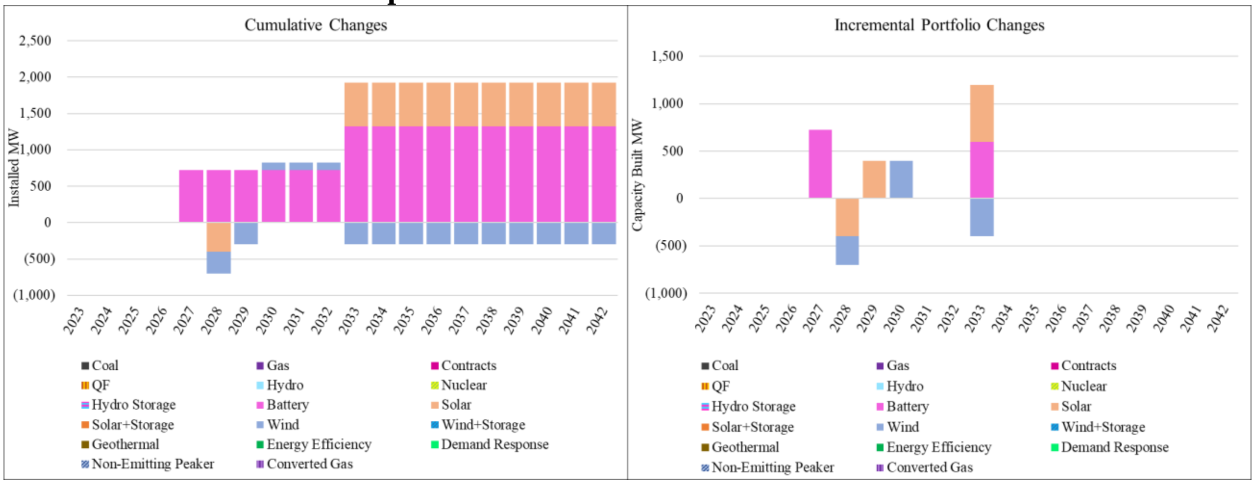
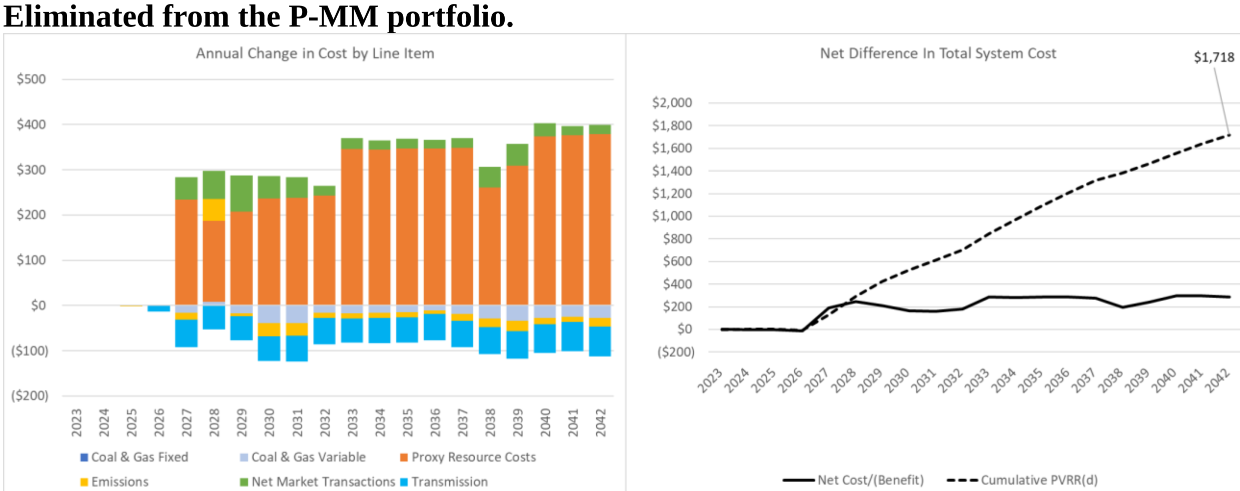


Figure 9.30 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the B2H transmission line is eliminated from the P1-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio without the B2H transmission line is $1,718 million higher cost than the P1-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without B2H is $1,716 million higher cost than the P1-MM portfolio.

Without the B2H transmission line, the cost for proxy resources is increased consistent with the changes in the resource portfolio, primarily cost of the 725 MW of incremental eight-hour battery resources if the B2H transmission line is not built. The changes in resources results in an increase in net market costs, indicating that without the B2H transmission line, the system would be more dependent on the market, despite additional resources added in southern Oregon and the Walla Walla area.

Figure 9.30 – Increase/(Decrease) in System Costs when the B2H Transmission Line is Eliminated from the P-MM portfolio.

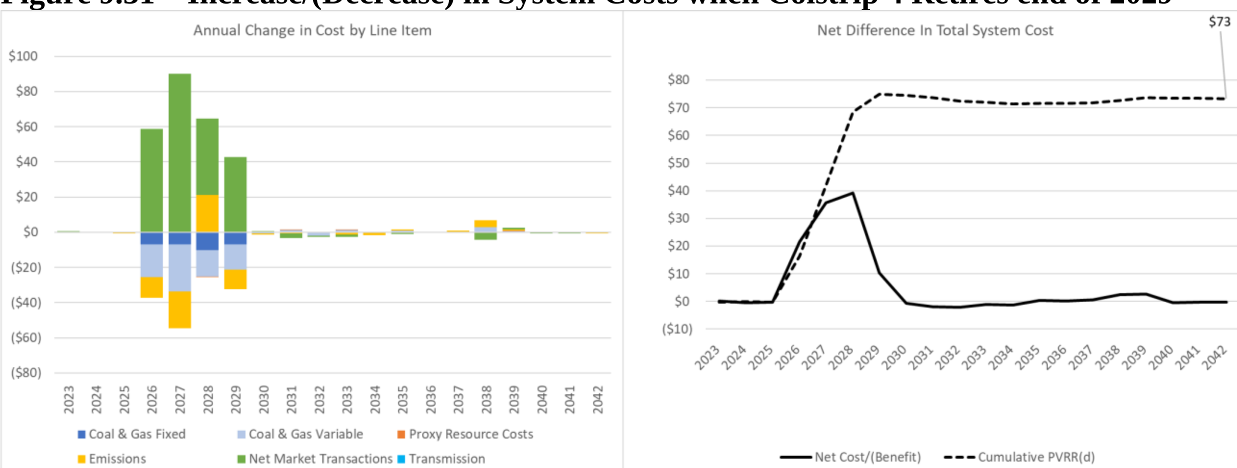


Colstrip Unit 3 and Unit 4 Retire Year-End of 2025 Variant (P17-Col3-4 RET25)

The P17-Colstrip 3 & 4 Retire in 2025 portfolio is a variant of the P-MM portfolio that exits PacifiCorp's participation in the generation of both Costrip 3 and Colstrip 4 coal plants at the end of 2025. The P-MM portfolio assumes that the company shifts it's contracted portion of Colstrip 3 to Colstrip unit 4 at the end of 2025 and continues operation through 2029. This counterfactual examines potential costs or benefits to the system of this continuation assumption. When this variant is compared to the P-MM portfolio, changes in system costs and dispatch related to this extension can be isolated.

Figure 9.31 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Colstrip 4 is retired early in the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that Colstrip 4 2025 retirement is $73 million higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, Colstrip 4 2025 retirement is $206 million higher cost than the P-MM portfolio.

Figure 9.31 – Increase/(Decrease) in System Costs when Colstrip 4 Retires end of 2029



Enable Cluster 1 Clover Transmission in Area 5/6/7 Variant (P18-Cluster East)

The Cluster East variant forces the model to incrementally select additional cluster study resources and their associated transmission within the Clover bubble. There are 3 cluster areas within the Clover bubble and this variant required that the model select all of them on top of the selections made in the preferred portfolio. This scenario does not change any other resource selections The goal of this study is to examine the impact of adding an even greater amount of renewable resources to the portfolio. The additional generator and storage resource selections in this variant are summarized in Figure 9.32. An additional 2,173 MW of co-located solar and storage are selected in 2029.

Figure 9.32 - Increase/(Decrease) in Resources With Addition of East Cluster

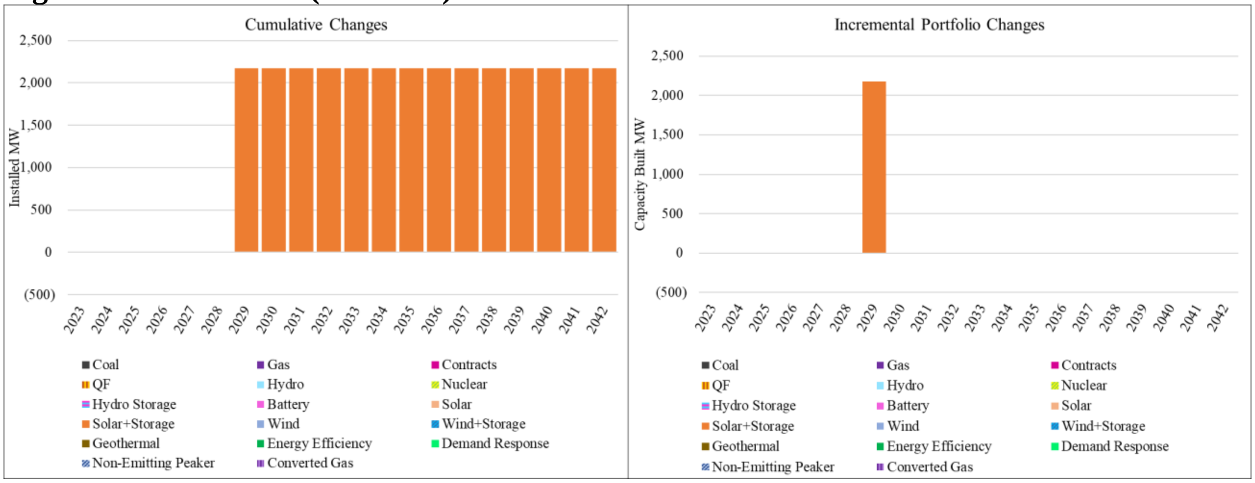
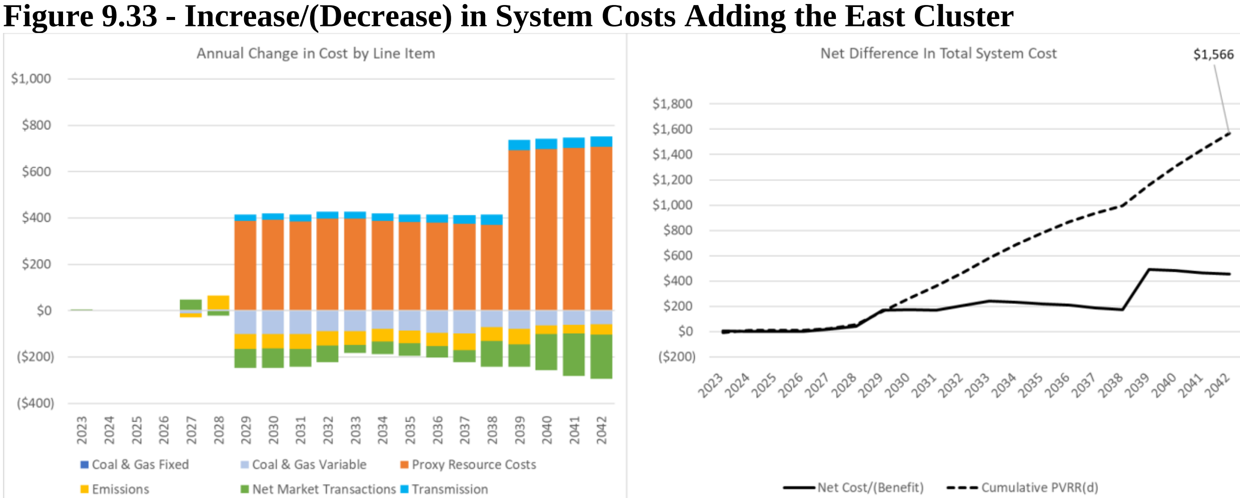


Figure 9.33 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, the East Cluster is added into the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that adding all Clover area cluster resources is $1,556 million higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio adding the East Cluster $1,947 million higher cost than the P-MM portfolio. Reduced reliance on the market and lower emissions costs are offset beginning in 2029higher DSM proxy resource and transmission costs.

Figure 9.33 - Increase/(Decrease) in System Costs Adding the East Cluster



Enable Cluster 1 Area 12 Transmission and Resources Variant (P19 Cluster West)

The Cluster West variant forces the model to incrementally select additional cluster study resources and their associated transmission within the Southern Oregon bubble. There are 3 cluster areas within the Southern Oregon bubble and this variant required that the model select all of them on top of the selections made in the preferred portfolio. This scenario does not change any other resource selections The goal of this study is to examine the impact of adding an even greater amount of renewable resources to the portfolio. The additional generator and storage resource selections in this variant are summarized in Figure 9.34. An additional 499 MW of co-located solar and storage are selected in 2028.

Figure 9.34 - Increase/(Decrease) in Resources With Addition of West Cluster

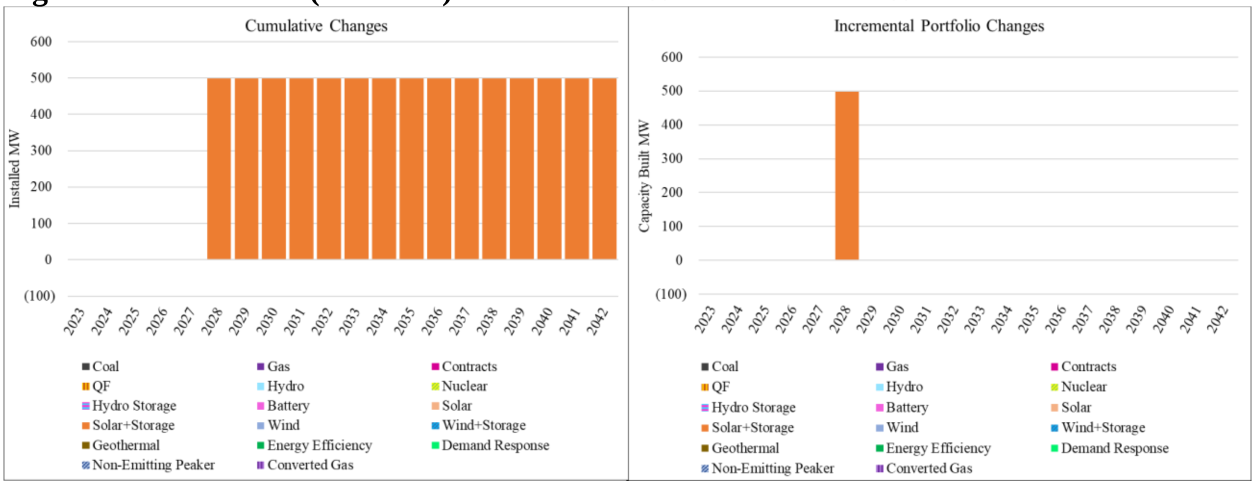
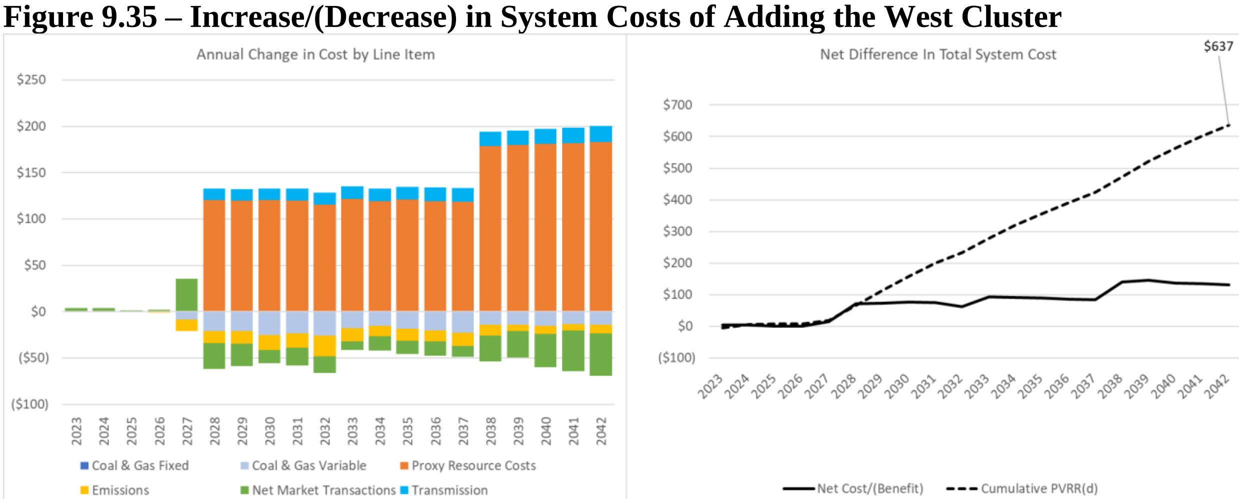


Figure 9.35 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, the West Cluster is added into the P-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that adding additional resources to the West Cluster is $637 million higher cost than the P-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio operation without the West Cluster restriction is $1,018 million higher cost than the P-MM portfolio. Higher proxy resource and transmission costs were not offset by reduced variable costs of tax credited renewables.

Figure 9.35 – Increase/(Decrease) in System Costs of Adding the West Cluster



Jim Bridger Unit 3 and Unit 4 Retrofit with CCUS in 2028 Variant (P20-JB3-4 CCUS)

The P20-JB34 CCUS portfolio is a variant of the preferred portfolio that forces a CCUS retrofit on Jim Bridger Unit 3 and 4 in 2028 and where Plexos optimizes the dispatch. When this variant is compared to the preferred portfolio, changes in proxy resources and system costs driven by the CCUS retrofit can be isolated. Because CCUS was not selected as a least-cost resource option in the preferred portfolio, this variant was produced to evaluate a means to comply with Wyoming HB 200.

For modeling purposes, PacifiCorp chose to force a CCUS retrofit (amine-based carbon capture + storage) at Jim Bridger Unit 3 and 4 as it was identified in the Company's HB 200 initial application for further evalution. The Company anticipates installation of CCUS at Jim Bridger Unit 3 and 4 would meet preliminary HB 200 targets. These units have the added advantage for amine-based carbon capture technology as they currently have selective catalytic reduction (SCR) system installed. However, there could be complications with co-ownership.

Carbon capture would begin in 2028, and Jim Bridger Unit 3 and 4 would operate with CCUS out to the end of 2039 to capture tax credits. There is a net reduction of capacity due to the parasitic load associated with the carbon capture equipment.[3]

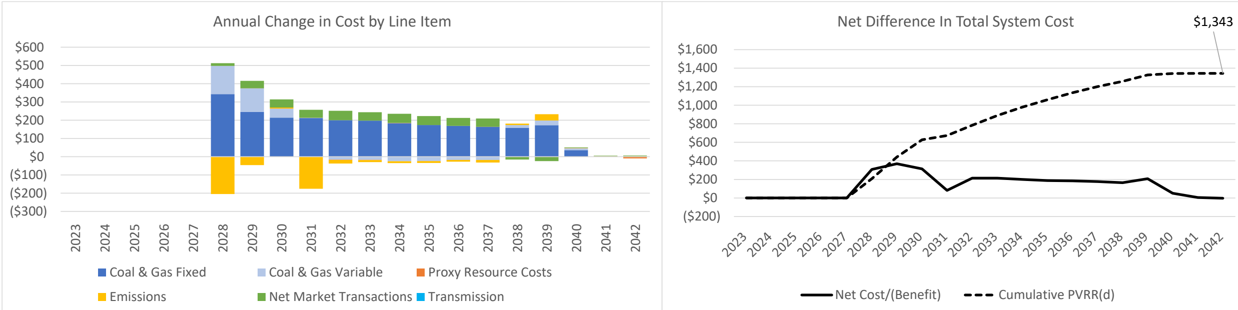
Figure 9.36 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when CCUS is installed on Jim Bridger Unit 3 and 4 in 2028. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio with CCUS installed on Jim Bridger Unit 3 and 4 project is $1,343 million higher cost than the preferred portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio with the Jim Bridger Unit 3 and 4 CCUS retrofit is $1,377 million higher cost than the preferred portfolio.

On an ST PVRR basis, capital cost assumptions for the CCUS retrofit at Jim Bridger Unit 3 and 4 would assume to foregoe the CCUS project when the higher heat rate and offtake fees dramatically reduces the unit generation making the project uneconomic.

When the CCUS retrofit is installed in 2028, the carbon capture technology increases the costs associated with Jim Bridger Unit 3 and 4. This shows up as increased fixed costs for coal and gas resources in the chart at left. This is partially offset by reduced emissions costs.

[3] Upon installation of the carbon capture equipment, Jim Bridger Unit 3 and 4's rating is 247 and 249 MW. As a coal-fired facility without carbon capture equipment, Jim Bridger Unit 3 and 4's rating is 349 and 351 MW.

Figure 9.36 – Increase/(Decrease) in System Costs when CCUS is Installed on Jim Bridger Unit 3 ands 4 in 2028



Portfolio Development Conclusions

Preferred portfolio remains the top performing portfolio among the variant portfolios. Further assessment is done relative to Washington CETA requirements, described further in a later section.

Modeling and Portfolio Selection Results

Final Preferred Portfolio Selection

P-MM entered the final evaluations as the top-performing portfolio for preferred portfolio selection.

Table 9.17 below shows the PVRR and risk-adjusted PVRR, ENS as a percentage of load, and CO_2 emissions for the 2023 IRP preferred portfolio under five price-policy scenarios.

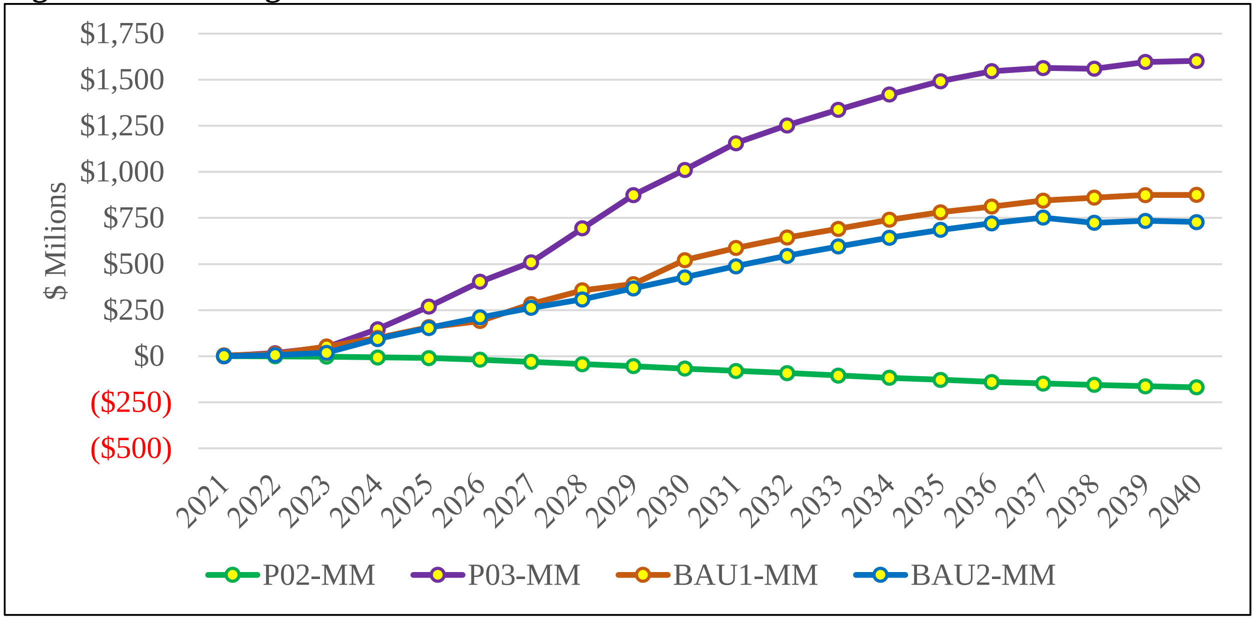
Table 9.17 - PVRR(d) of the P-MM-Portfolio Under Varying Price-Policy Scenarios

Study Name	ST PVRR ($m)	ST PVRR plus 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2023-2042 (Thousand Tons)
P-LN	$36,181	$36,155	0.00200%	306,945
P-MN	$36,257	$36,252	0.00201%	313,970
P-MM	$37,438	$37,305	0.00199%	330,442
P-HH	$45,540	$45,540	0.00197%	328,142
P-SC	$58,238	$58,192	0.00201%	332,257

Customer Rate Pressure

Figure 9.39 shows the difference in the cumulative PVRR, as an indicator of rate pressure over time, among the initial portfolios discussed earlier in this chapter relative to the 2022 IRP preferred portfolio, P-MM applying medium gas, medium CO_2 price-policy assumptions. All Portfolios P03, BAU1 and BAU2 trend higher in costs over the planning horizon relative to P-MM whereas P02 trends lower in costs notably, as it does not include Washington-situs assigned resources relative to the requirements of CETA.

Figure 9.39 – Change in the Cumulative PVRR relative to P-MM-CETA



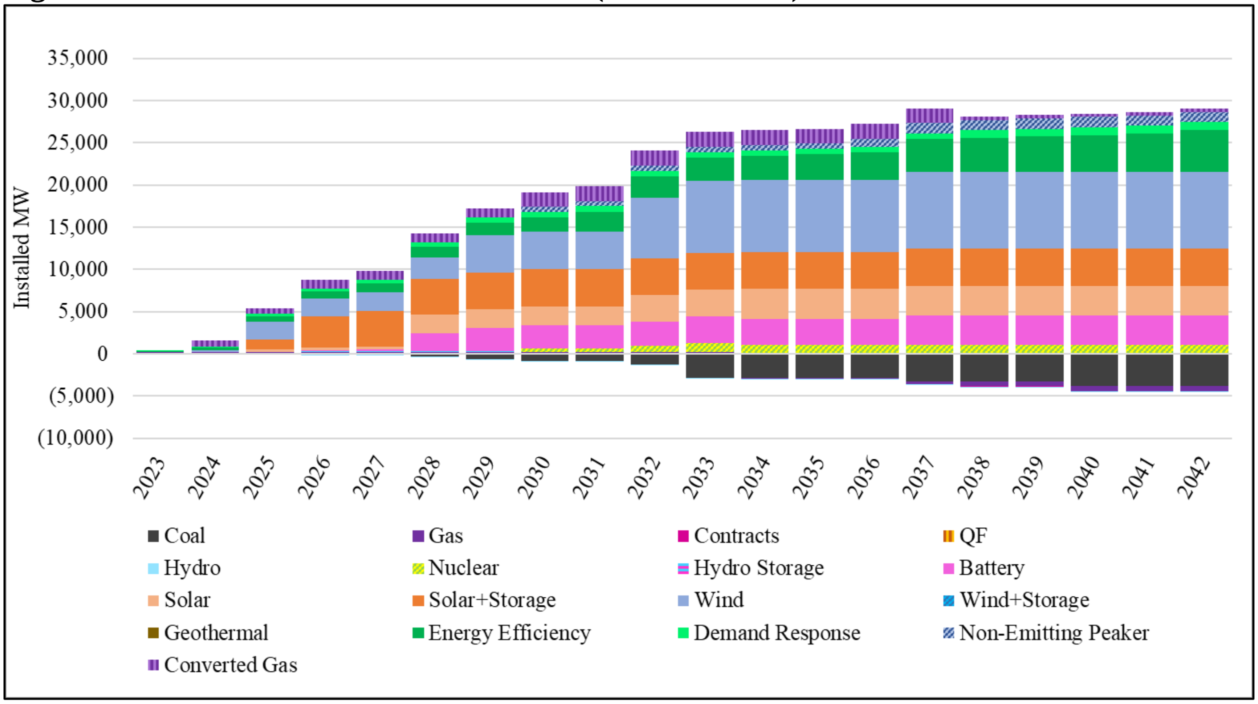
The 2023 IRP Preferred Portfolio

PacifiCorp's selection of the 2023 IRP preferred portfolio, P-MM, is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 9.40 shows that PacifiCorp's 2023 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management resources, significant storage resources, advanced nuclear, and non-emitting peaking resources.

The 2023 IRP preferred portfolio includes new resources from the 2020 All-Source Request for Proposals (RFP). These projects include 1,792 MW of wind, 495 MW of solar additions with 200 MW of battery storage capacity. These resources will come online in the 2024-to-2025 timeframe. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River I (50 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage, for which the 2022AS RFP is currently soliciting and evaluating resources to fulfill.

The 2023 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, anticipated to achieve online status by summer 2030. Through 2033, the 2023 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources, and through 2037, the preferred portfolio includes1,240 MW of non-emitting peaking resources. Advancement of these two technologies will be critical to the planned transition of our coal resources in a way that will minimize impacts to our employees and our communities. Over the 20-year planning horizon, the 2023 IRP preferred portfolio includes 9,114 MW of new wind and 7,855 MW of new solar.

Figure 9.40 – 2023 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the 2023 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2023 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59-mile, high-voltage (230-kilovolt) transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.

The 2023 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway ("B2H"), which connects the Longhorn substation near the town of Boardman in Oregon to the Hemingway substation in Idaho, which will come online in 2026. By exchanging certain transmission assets with Idaho Power Company, PacifiCorp will receive additional transmission rights between Hemingway and the Populus substation in Idaho, which is closely tied to existing and future PacifiCorp transmission connecting to Utah and

Wyoming. At the Oregon end of the B2H line, additional transmission upgrades are planned to connect B2H to growing loads.

New since the 2021 IRP, the 2023 IRP preferred portfolio includes a 200 mile high-voltage 500-kilovolt transmission line from Anticline substation in central Wyoming to Populus substation in southeastern Idaho known as Energy Gateway West Sub-Segment D.3, planned to come online in 2028.

Further, the 2021 IRP preferred portfolio further included near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to serve our customers. New for the 2023 IRP, many of these transmission upgrades and the accompanying resources reflect the results of PacifiCorp's "cluster study" process for evaluating proposed resource additions. By evaluating all newly proposed resource additions in an area at the same time, the cluster study process identifies collective solutions that can allow projects that are ready to move forward to do so in a timely fashion. As a result many of the transmission upgrades and resource additions in the first five years of the IRP preferred portfolio reflect cluster study requests submitted in the past two years. Table 9.18 summarizes the incremental transmission projects in the 2023 IRP preferred portfolio.

Table 9.18 – Transmission Projects Included in the 2023 IRP Preferred Portfolio 2023-2026[1,2]

<table>
<tr><th>Year</th><th colspan="2">From</th><th>To</th><th>Export (MW)[1]</th><th>Import (MW)[1]</th><th>Inter-connect (MW)</th><th>Description</th></tr>
<tr><td rowspan="2">2024</td><td colspan="3">Multistate Path C Improvement</td><td>0</td><td>0</td><td>100</td><td>Path C enables Utah, Idaho, Wyoming interconnection, additional transmission options</td></tr>
<tr><td colspan="3">Within Yakima WA Transmission Area</td><td>0</td><td>0</td><td>80</td><td>Union Gap-Midway 230 kV Line and substation - Yakima, enables additional transmission options</td></tr>
<tr><td rowspan="3">2025</td><td colspan="3">Within Willamette Valley WA Transmission Area</td><td>0</td><td>0</td><td>9</td><td>Cluster 2 Area 22 - Willamette Valley, enables 9 MW of solar</td></tr>
<tr><td colspan="2">Walla Walla WA</td><td>Yakima WA</td><td>400</td><td>400</td><td>200</td><td>Walla Walla - Wine Country 230 kV line and integration, enables 200 MW of wind in 2032</td></tr>
<tr><td>GWS</td><td>Wyoming East</td><td>Clover UT</td><td>1,200</td><td>1,700</td><td>2,030</td><td>Energy Gateway South, enables 1,716 MW wind, 315 MW solar and storage, and future transmission</td></tr>
<tr><td rowspan="10">2026</td><td colspan="3">Within Borah-Populus ID Transmission Area</td><td>0</td><td>0</td><td>1,100</td><td>Cluster 2 Area 5 - Borah, enabling 1,100 MW solar and 1,100 MW storage</td></tr>
<tr><td colspan="3">Within BPA NITS (OR) Transmission Area</td><td>0</td><td>0</td><td>160</td><td>Cluster 2 Area 21 - BPA NITS, enables 160 MW storage</td></tr>
<tr><td colspan="3">Within Central Oregon Transmission Area</td><td>0</td><td>0</td><td>240</td><td>Transition Cluster Area 8 - Central Oregon, enables 200 MW solar and 200 MW storage</td></tr>
<tr><td colspan="3">Within Clover UT Transmission Area</td><td>0</td><td>0</td><td>331</td><td>TCA4: Q820 contingent facilities - Utah South, enables 300 MW solar and 300 MW storage</td></tr>
<tr><td colspan="3">Within Willamette Valley OR Transmission Area</td><td>0</td><td>0</td><td>719</td><td>Cluster 2 Area 23 - Willamette Valley, enables 474 MW solar and 474 MW storage</td></tr>
<tr><td colspan="3">Within Yakima WA Transmission Area</td><td>0</td><td>0</td><td>450</td><td>Cluster 1 Area 10 - Yakima, enables 450 MW solar and 707 MW storage</td></tr>
<tr><td rowspan="4">B2H</td><td>Borah-Populus ID</td><td>Hemingway ID</td><td>600</td><td>300</td><td>600</td><td>B2H - Idaho Power Asset Transfer, enabling 300 MW wind, 400 MW solar, 600 MW storage</td></tr>
<tr><td>Hemingway ID</td><td>Longhorn OR</td><td>818</td><td>0</td><td>0</td><td>B2H component</td></tr>
<tr><td>Longhorn OR</td><td>McNary OR</td><td>300</td><td>0</td><td>0</td><td>B2H - Longhorn Load component</td></tr>
<tr><td>Walla Walla WA</td><td>Borah ID</td><td>300</td><td>0</td><td>0</td><td>B2H - IPC PTP Eastbound component</td></tr>
</table>

Table 9.19 - Transmission Projects Included in the 2023 IRP Preferred Portfolio 2027-2042[1,2]

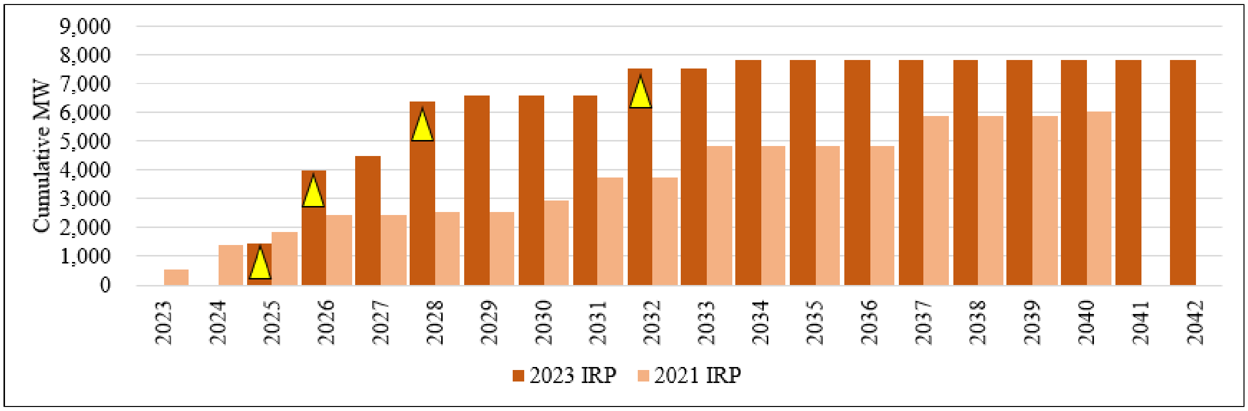
<table>
<tr><th>Year</th><th colspan="2">From</th><th>To</th><th>Export (MW)[1]</th><th>Import (MW)[1]</th><th>Inter-connect (MW)</th><th>Description</th></tr>
<tr><td>2027</td><td colspan="3">Within Walla Walla WA Transmission Area</td><td>0</td><td>0</td><td>733</td><td>Cluster 2 Area 15 - Walla Walla, enabling 100 MW wind, 483 MW solar, 628 MW storage</td></tr>
<tr><td rowspan="2">2028</td><td colspan="3">Within Yakima WA Transmission Area</td><td>0</td><td>0</td><td>180</td><td>230 kV Union Gap-Pomona Heights, prerequisite of Union Gap-Wine Country part b</td></tr>
<tr><td colspan="2">Jim Bridger WY</td><td>Borah-Populus ID</td><td>1,621</td><td>1,621</td><td>357</td><td>Segment D3, Transition Cluster Area 1, enables 357 MW wind</td></tr>
<tr><td rowspan="4">2029</td><td colspan="3">Within Goshen ID Transmission Area</td><td>0</td><td>0</td><td>662</td><td>Transition Cluster 5/Cluster 1 Area 3 - Goshen, enables 200 MW wind and 549 MW storage</td></tr>
<tr><td colspan="2">Wyoming East</td><td>Jim Bridger WY</td><td>950</td><td>950</td><td>1,209</td><td>D2.2/D1.2, Cluster 1 Area 1, enables 1815 MW of wind</td></tr>
<tr><td rowspan="2">D3</td><td>Utah North</td><td>Borah-Populus ID</td><td>1,000</td><td>600</td><td>0</td><td>D3 supporting projects (west), enabled by D3</td></tr>
<tr><td>Wyoming East</td><td>Jim Bridger WY</td><td>728</td><td>728</td><td>298</td><td>D3 supporting projects (east), enables 298 MW wind</td></tr>
<tr><td>2030</td><td colspan="3">Within Utah North Transmission Area</td><td>0</td><td>0</td><td>558</td><td>Path C improvements: mostly 138 kV, enables 300 MW wind and 606 MW non-emitting peaker</td></tr>
<tr><td rowspan="2">2032</td><td colspan="3">Within Portland North Coast Transmission Area</td><td>0</td><td>0</td><td>130</td><td>Birdsdale 230-115 kV and Portland 115 kV reinforcement, enables 130 MW wind</td></tr>
<tr><td colspan="3">Within Yakima WA Transmission Area</td><td>0</td><td>0</td><td>100</td><td>230 kV Union Gap-Wine Country part b, enables 500 MW wind</td></tr>
<tr><td>2033</td><td colspan="2">Southern Oregon</td><td>Central Oregon</td><td>389</td><td>389</td><td>935</td><td>Del Norte-Central Oregon 500kV[2], enables 1,382 MW wind and 303 MW non-emitting peaker</td></tr>
<tr><td>2037</td><td colspan="2">Walla Walla WA</td><td>Willamette Valley WA</td><td>30</td><td>30</td><td>12</td><td>500 kV Walla Walla-S.Lebanon and Reinforcement[2], facilitates regional transmission</td></tr>
</table>

1 - TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
2 - Energy Gateway South is modeled in the 2021 IRP as a contingent option with bids in the 2020 All-Source Request for Proposals. Other transmission options prior to 2026 are not modeled as transmission requirements and costs are accounted for in the 2020 All-Source Request for Proposals transmission cluster study for all other resource bids.
* - Reclaimed transmission is committed with resources with a commercial operation date later than the date of retirement.

New Solar Resources

The 2023 IRP preferred portfolio includes 3,993 MW by the end of 2025, more than 6,200 MW by the end of 2027, and more than 7,800 MW of new solar is online by the end of 2031, as shown in Figure 9.41.

Figure 9.41 – 2023 IRP Preferred Portfolio New Solar Capacity*

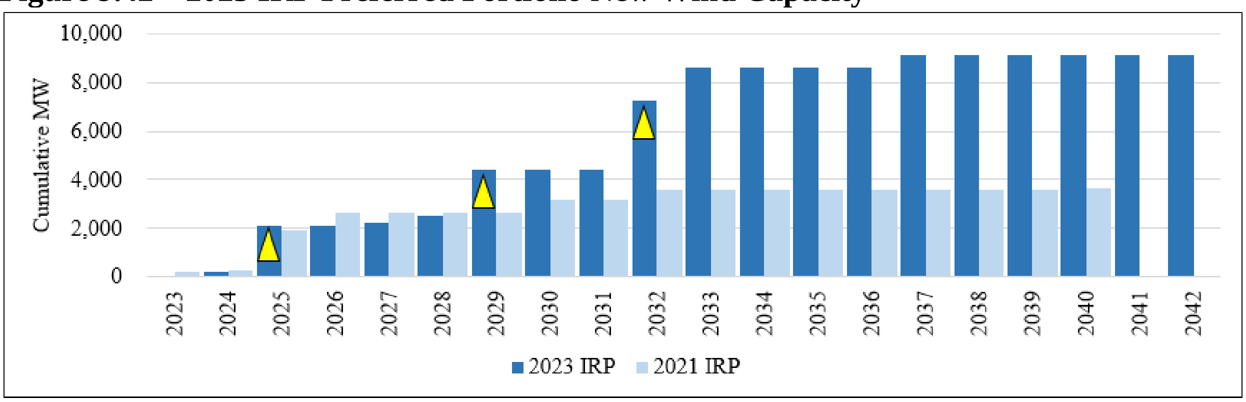


* 2023 IRP solar capacity shown in the figure includes solar resources coming via the 2020 All-Source Request for Proposals by the end of 2024. Resources are shown in the first full year of operation (the year after the year-online dates).

New Wind Resources

As shown in Figure 9.42, by year-end 2024, PacifiCorp's 2023 IRP preferred portfolio includes 2,131 MW of new wind generation resulting from the 2020 AS RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). By year-end 2028, the 2023 IRP preferred portfolio includes an additional 2,300 MW of new wind, and more than 7,200 MW of cumulative new wind by the end of 2031.

Figure 9.42 – 2023 IRP Preferred Portfolio New Wind Capacity*

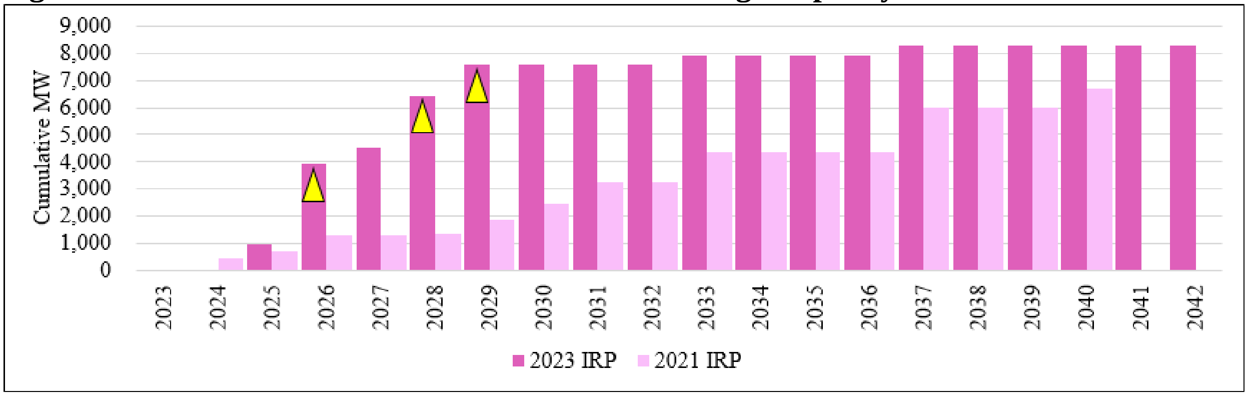


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates).

New Storage Resources

New storage resources in the 2023 IRP preferred portfolio are summarized in Figure 9.43. The 2023 IRP preferred portfolio presents a quickly escalating curve for storage selections in years 2023 through 2029, and includes over 3,900 MW by the end of 2025 – the majority of which is expected to be collocated with renewable resources by proxy selection or is paired with solar resources resulting from the 2020 All-Source RFP. By year-end 2028, the 2023 IRP includes nearly 7,600 MW of storage, comprised of 7,560 MW of proxy lithium ion battery storage and 35 MW of pumped hydro. 150 MW of long-duration storage appears by year-end 2032 and another 200 MW by the end of 2036.

Figure 9.43 – 2023 IRP Preferred Portfolio New Storage Capacity*

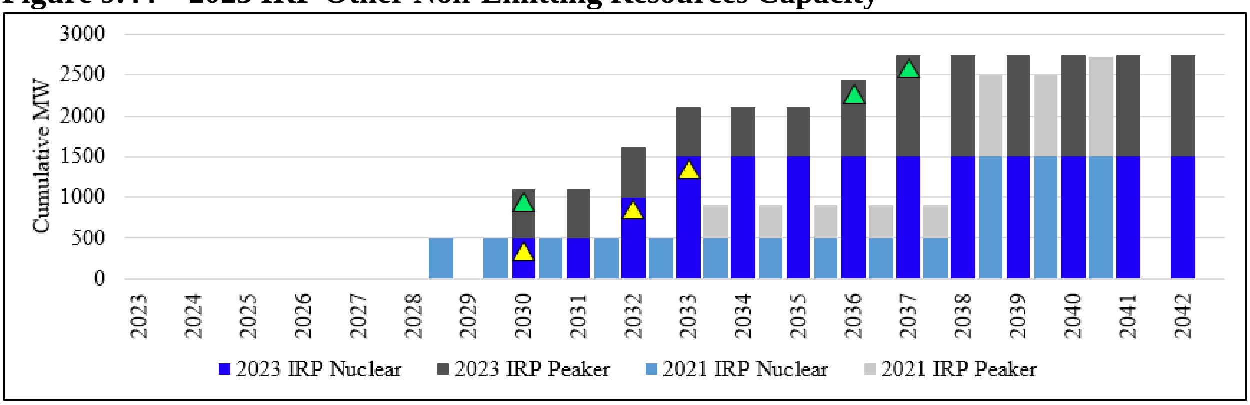


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Other Non-Emitting Resources

The 2023 IRP includes new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. As shown in 9.44, the 500 MW advanced nuclear Natrium™ demonstration project is scheduled to come online by summer 2030. By year-end 2032, the 2023 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources. The 2023 IRP also includes 606 MW of non-emitting peaking resources by year-end 2029, increasing to 1,240 MW by the end of 2036. The advancement of these new technologies are critical to the planned transition of PacifiCorp's coal fleet.

Figure 9.44 – 2023 IRP Other Non-Emitting Resources Capacity*

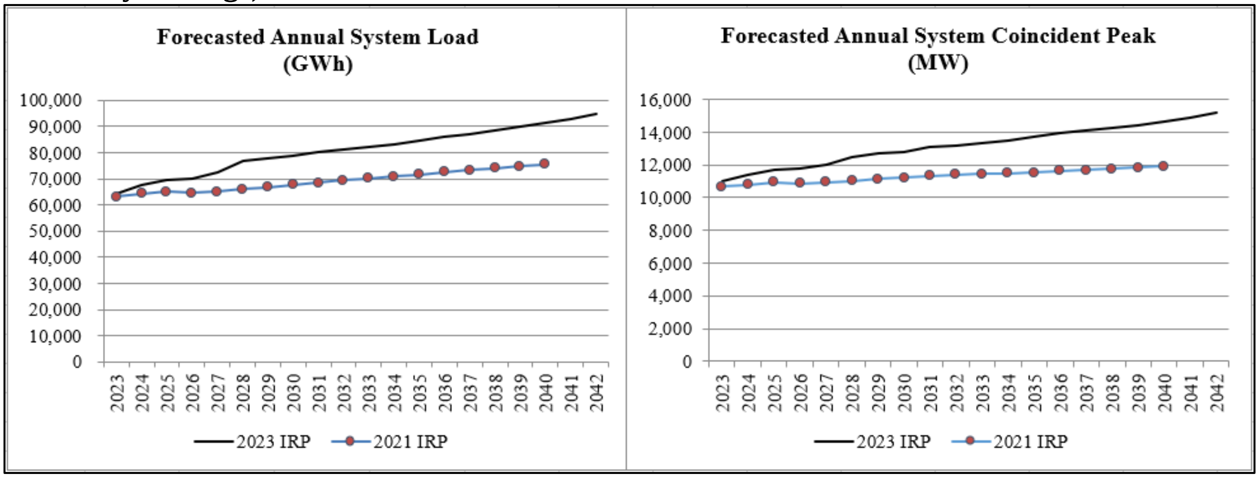


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 9.45 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2021 IRP. On average, forecasted system load is up 14.9 percent and forecasted coincident system peak is up 14.9 percent when compared to the 2021 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 2.07 percent for load and 1.70 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from new large customers driving up the commercial forecast and an increased residential forecast.

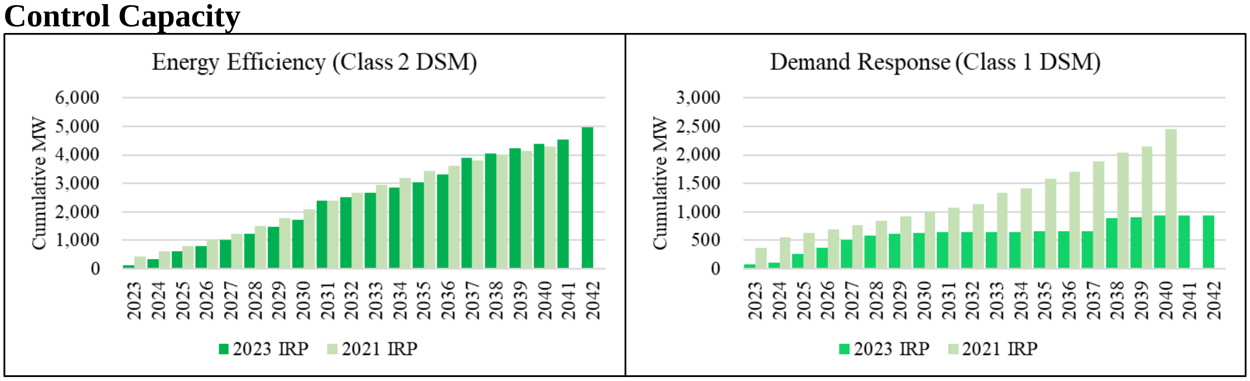
Figure 9.45 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 9.46 compares total energy efficiency capacity savings in the 2023 IRP preferred portfolio relative to the 2021 IRP preferred portfolio and includes 4,953 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows a need for incremental demand response programs. The chart to the right in Figure 9.46 compares cumulative demand response program capacity in the 2023 IRP preferred portfolio relative to the 2021 IRP preferred portfolio and does not include capacity from existing programs. The 2023 IRP has a cumulative capacity of demand response programs reaching 929 MW by 2042 which represents a 264% decrease relative to the 2021 IRP. This decrease is the result of improved accounting for demand response resources and their potential overlap with one another. In the 2021 IRP, resources from the 2021 DR RFP were modeled concurrently with CPA resources to evaluate all possible resources. The result was an upper theorical maximum of resources that did not account for overlap in end-uses and programs. .

Figure 9.46 – 2021 and 2923 IRP Preferred Portfolio Energy Efficiency and Direct Load Control Capacity



Wholesale Power Market Prices and Purchases

Figure 9.47 shows that the 2023 IRP's base case forecast for natural gas prices has increased along with an increase in wholesale power prices for most years relative to those in the 2021 IRP. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The higher power prices observed in the 2023 IRP are primarily driven by the assumption of higher natural gas prices than what was assumed in the 2021 IRP. Wholesale power prices are higher in 2023 to 2030 due to weather conditions, higher inflation impacting new resource costs, and market volatility until the market settles. Moreover, the 2023 IRP assumed higher natural gas prices than the 2021 IRP due to impacts by world events notably including the war in Ukraine. Henry Hub in particular, is impacted by higher natural gas demand increasing liquefied natural gas exports. While not shown in the figure below, the 2023 IRP also evaluated low and high price scenarios when assessing the cost and risk of different resource portfolios.

Figure 9.47 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

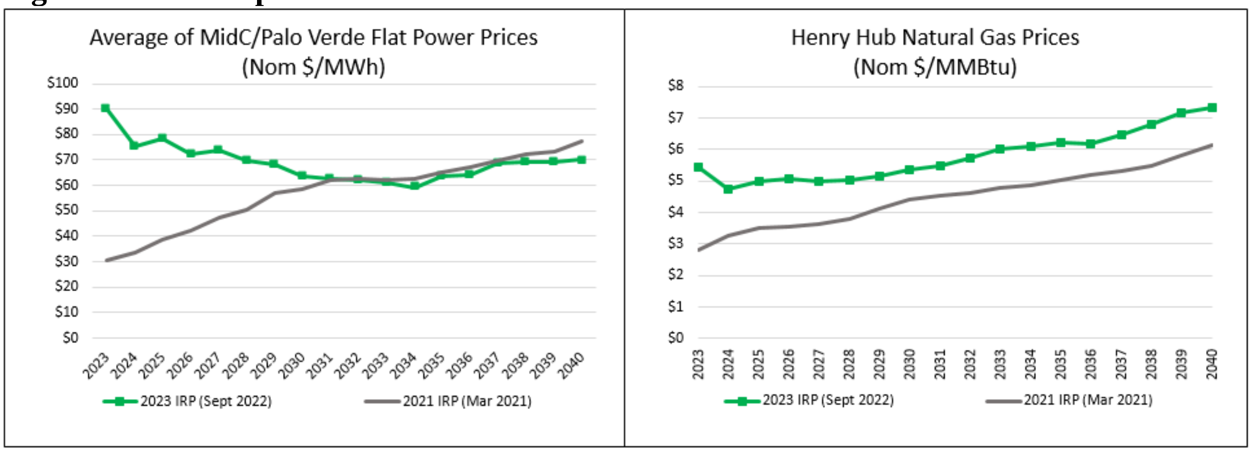
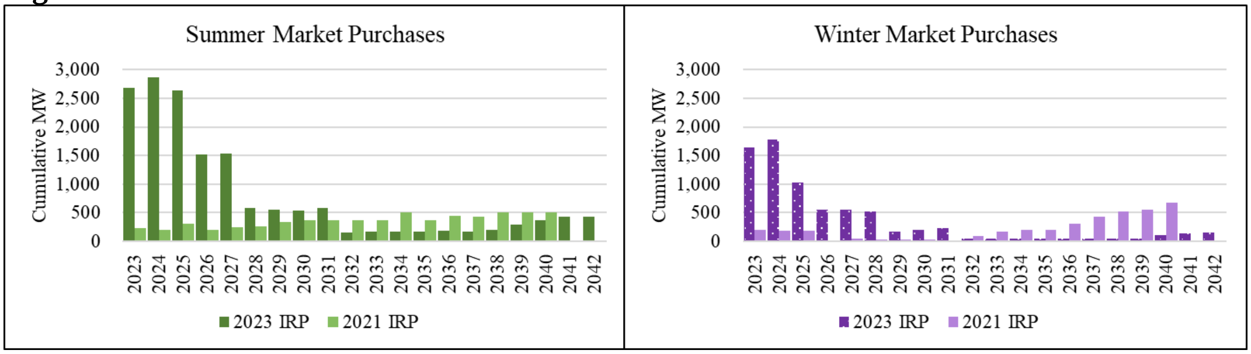


Figure 9.48 below, shows an overall increase in reliance on wholesale power market firm purchases in the 2023 IRP preferred portfolio relative to the wholesale power market purchases included in the 2021 IRP preferred portfolio. In years 2023 through 2027, the magnitude of this increase is exaggerated due to the accounting of purchases to meet near-term load obligations in the 2021 IRP, where additional purchases could have been assumed to meet deficiencies. While wholesale power market purchases are higher in 2028 through 2031 compared to the 2021 IRP, purchases are relatively less through the remaining ten years of the planning period, driven largely by the influx of cost-effective renewable energy and investments in new technology that support the planned transition for PacifiCorp's coal fleet. PacifiCorp is actively participating in regional efforts to develop day-ahead markets and a resource adequacy program that will help unlock regional diversity and facilitate market transactions over the long term.

Figure 9.48 – 2021 IRP Preferred Portfolio Market Purchases



*Note: In the 2021 IRP, higher near-term market purchases were represented by system shortfalls that were assumed to be avoided through market purchases disallowed in the model. In the 2023 IRP this methodology was enhanced to represent the coverage of these shortfalls as market purchases, declining steadily over the next several years as new resource additions, and particularly battery storage, come online.

Coal and Gas Retirements/Gas Conversions

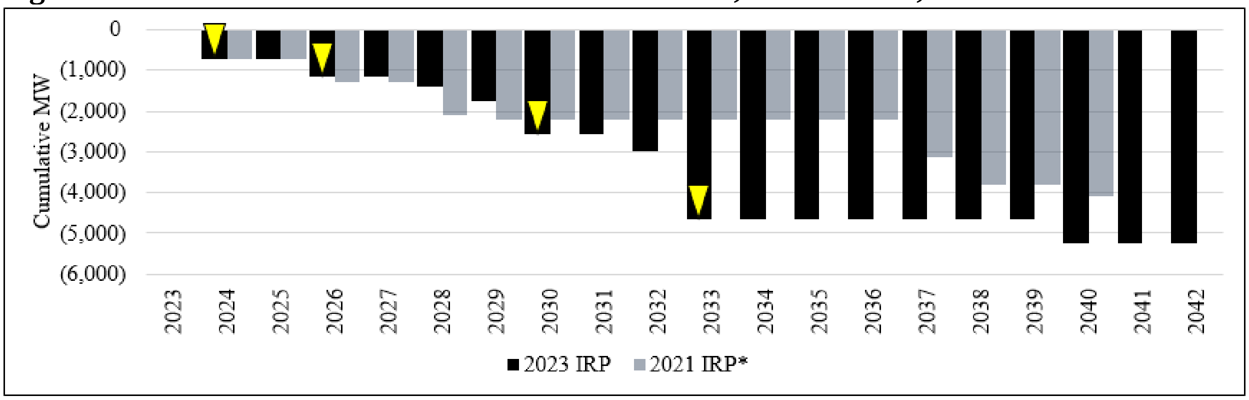
Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement or gas conversion of 13 units by 2030 and 20 units by year-end 2032. The final two coal units retire by 2039, or three years ahead of the end of the planning period, with the path to decarbonization supported by new non-emitting technologies. As shown in Figure 9.49, coal unit retirements/gas peaker conversions in the 2023 IRP preferred portfolio will reduce coal-fueled generation capacity by 1,153 MW by the end of 2025, and over 2,999 MW by 2032.

Coal unit exits, retirements, and gas conversions scheduled under the preferred portfolio include:

- 2023 = Jim Bridger Units 1-2, converted to natural gas in 2024 (same as in the 2021 IRP)
- 2025 = Craig Unit 1 retirement (same as in the 2021 IRP)
- 2025 = Colstrip Unit 3 exit (same as in the 2021 IRP)
- 2026 = Naughton Units 1-2, converted to natural gas in 2026, operates through 2036 (retired 2025 in the 2021 IRP)
- 2027 = Dave Johnston Units 3 retirement (same as in the 2021 IRP)
- 2027 = Hayden Unit 2 retirement (same as in the 2021 IRP)
- 2028 = Dave Johnston Units 1-2 retirement (retired 2027 in the 2021 IRP)
- 2028 = Craig Unit 2 retirement (same as in the 2021 IRP)
- 2028 = Hayden Unit 1 retirement (same as in the 2021 IRP)
- 2029 = Colstrip Unit 4 exit, Colstrip Unit 3 share is consolidated into Colstrip Unit 4 in 2025 (retired 2025 in the 2021 IRP)
- 2030 = Jim Bridger Units 3-4, converted to natural gas in 2030, operates through 2037 (retired 2037 without conversion in 2021 IRP)

- 2031 = Hunter Unit 1 retirement, SNCR installed 2026 (outside of 2021 IRP planning horizon, retiring 2042)
- 2032 = Hunter Units 2-3 retirement, SNCR installed 2026 (outside of 2021 IRP planning horizon, retiring 2042)
- 2032 = Huntington Units 1-2 retirement, SNCR installed 2026 (retired 2036 in 2021 IRP)
- 2039 = Dave Johnston Unit 4 retirement (retired 2027 in 2021 IRP)
- 2039 = Wyodak retirement, SNCR installed 2026 (retired 2039 without SNCR in 2021 IRP)

Figure 9.49 – 2021 IRP Preferred Portfolio Coal Exits, Retirements, and Gas Conversions*



* Note: Coal exits and retirements are assumed to occur by the end of the year before the year shown in the graph. The graph shows the year in which the capacity will not be available for meeting summer peak load. All figures represent PacifiCorp's ownership share of jointly owned facilities.

In addition to the coal unit exits, retirements, and gas conversions outlined above, the preferred portfolio reflects 2,660 MW natural gas retirements through 2042. This includes Gadsby at the end of 2032, Naughton Units 1, 2, and 3 at the end of 2036, Hermiston at the end of 2036, and Jim Bridger Units 1, 2, 3, and 4 at the end of 2037.

Carbon Dioxide Equivalent Emissions

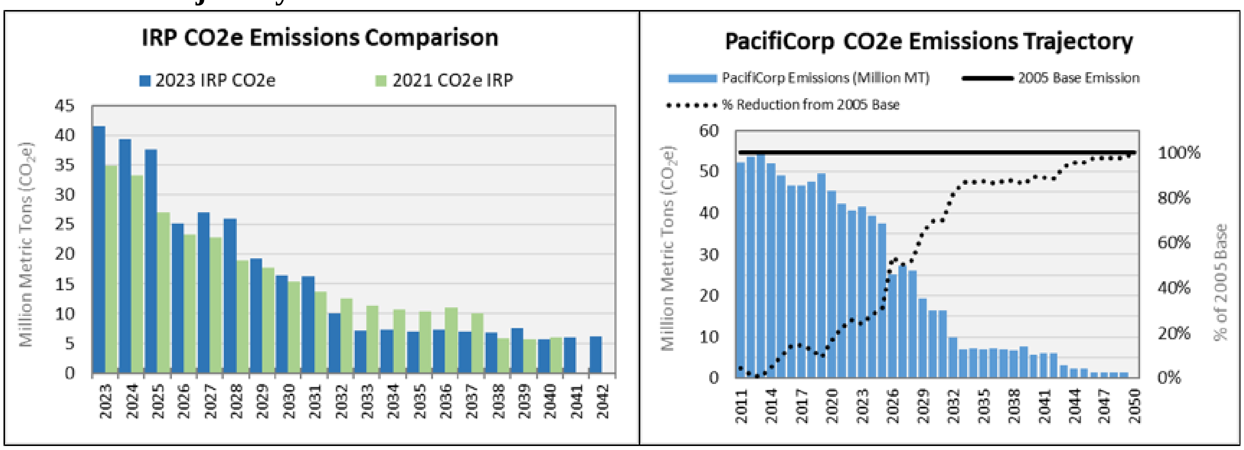
The 2023 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide and other carbon dioxide equivalent emissions resulting in a total (CO_2e) emissions. PacifiCorp's emissions have been declining and continue to decline related to several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new non-emitting resources, storage, transmission, Regional Haze compliance that capitalizes on flexibility, and the Ozone Transport Rule.

The chart on the left in Figure 9.50 compares projected annual CO_2e emissions between the 2023 IRP and 2021 IRP preferred portfolios. In this graph, emissions are assigned to market purchases. In the current 2023 IRP emissions are higher than projected in the 2021 IRP until 2032, this is a result of higher load forecast in the 2023 IRP. In addition, the 2023 IPR contains several coal plants converting to gas, but with higher dispatch of gas contributing to the uptick in emissions. By 2032, average annual CO_2e emissions are down 21 percent relative to the 2021 IRP preferred portfolio.

By 2040 emissions are comparable to the 2021 IRP while generation has increased by 31% showing that the overall emissions rate is lower under 2023 IRP portfolio. By the end of the planning horizon, system CO_2e emissions are projected to fall from 41.5 million metric tons in 2023 to 6.2 million tons in 2042—a reduction of 85 percent.

The chart on the right in Figure 9.50 includes historical data, assigns emissions at a rate of 0.428 metric tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, of 54.6 million metric tons, system CO_2 equivalent emissions are down 31 percent in 2025, 70 percent in 2030, 87 percent in 2035, 89 percent in 2040, 96 percent in 2045, and 100 percent in 2050.

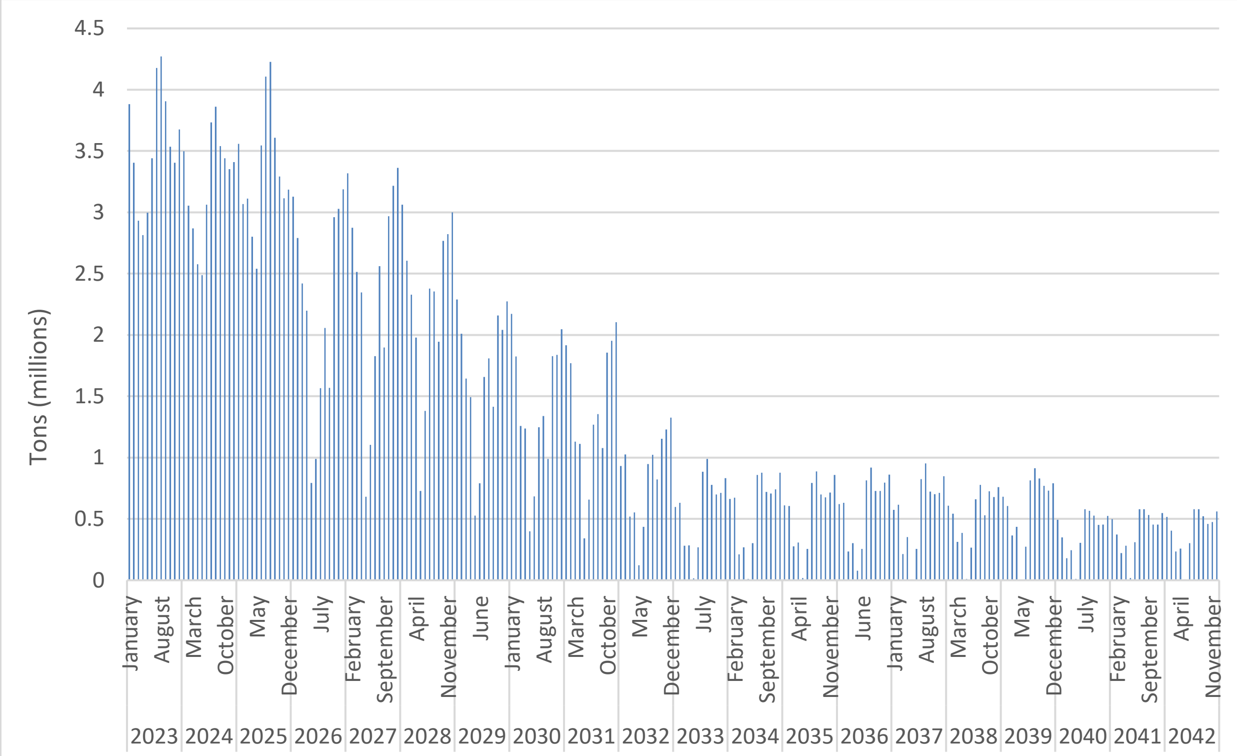
Figure 9.50 – 2021 IRP Preferred Portfolio CO2 Emissions and PacifiCorp CO2 Equivalent Emissions Trajectory*



*Note: PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2022 from owned facilities, specified sources and unspecified sources. From 2023 through the end of the twenty-year planning period in 2042, emissions reflect those from the 2023 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.428 metric tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2042, emissions reflect the rolling average emissions of each resource from the 2023 IRP preferred portfolio through the life of the resource or the end of the contract. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be discussed in more detail in its Clean Energy Plan.

Monthly CO_2 emissions are available for the preferred portfolio as shown in
47 below.

Figure 9.51 – Monthly CO2 emissions per year for the preferred portfolio



Renewable Portfolio Standards

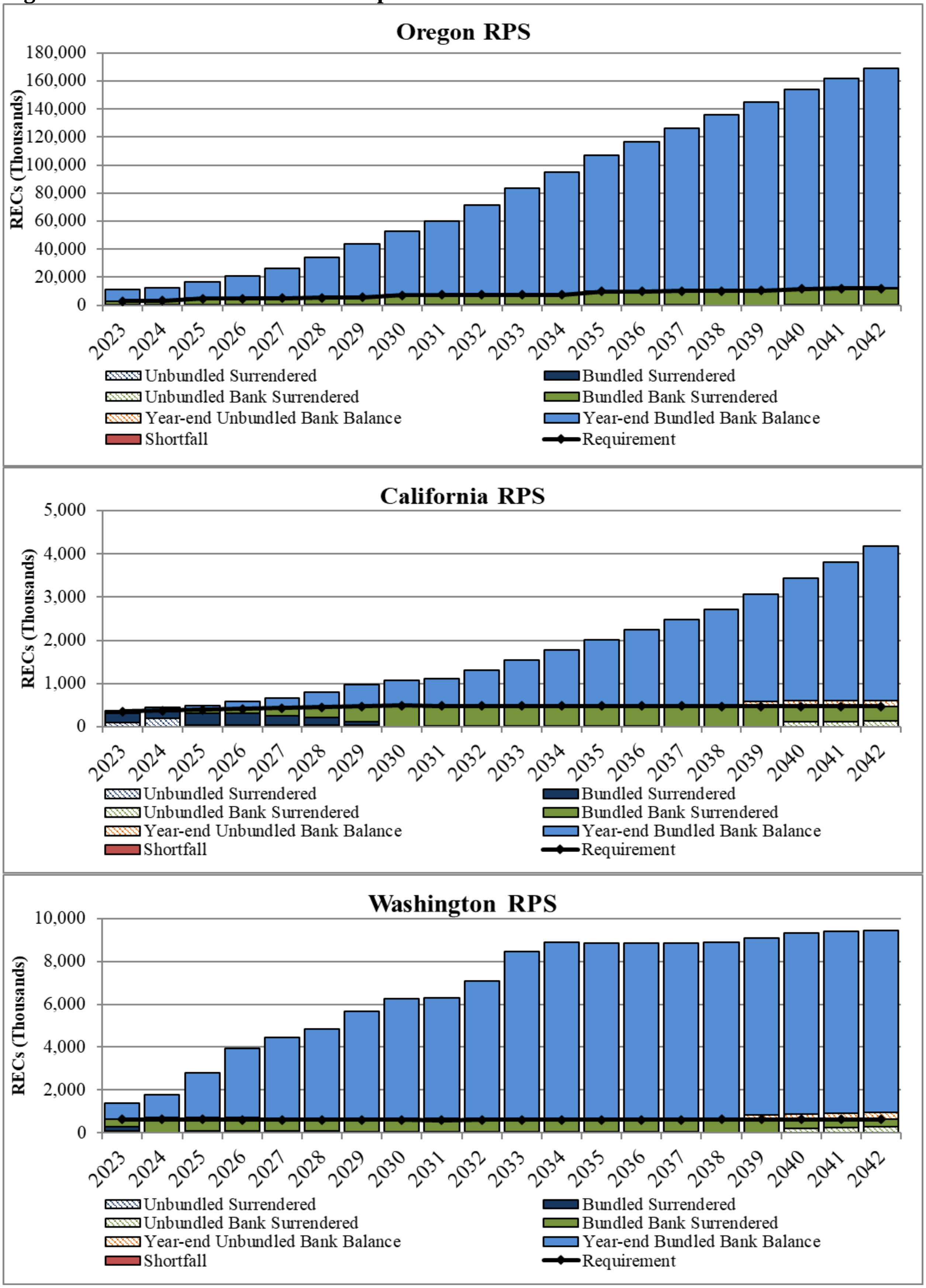
Figure 9.52 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2042 with the addition of new renewable resources. Washington RPS compliance is also achieved through 2042 with the addition of new renewable resources. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington receives a system share of renewable resources across the PacifiCorp's system.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as REC purchases throughout the 2023 IRP study period. The ramping RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in the near term. New renewable resources in the 2023 IRP preferred portfolio mitigate that shortfall, but the company is seeking to purchase approximately 200,000 RECs the near term.

While not shown in Fiure 9.52, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources and transmission in the 2023 IRP preferred portfolio.

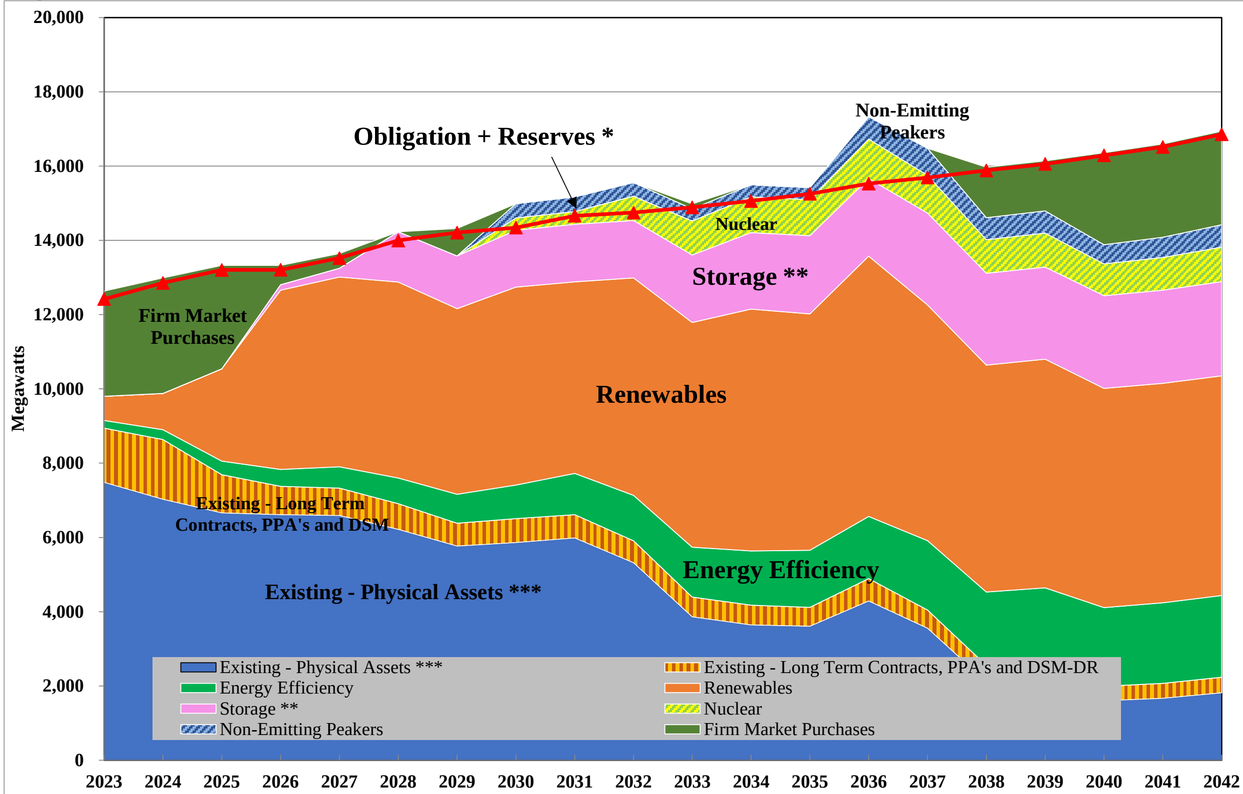
Figure 9.52 – Annual State RPS Compliance Forecast



Capacity and Energy

Figure 9.53 displays how preferred portfolio resources meet PacifiCorp's capacity needs over time. Through 2042, PacifiCorp meets its capacity needs, including a 13% planning reserve margin, through incremental acquisition of wind and solar resources and hybrid renewables (with storage) enabled by investment in transmission infrastructure, nuclear resources, strand alone storage resources, new DSM, non-emitting peaker resources, and wholesale power market purchases.

Figure 9.53 – Meeting PacifiCorp's Capacity Needs with Preferred Portfolio Resources



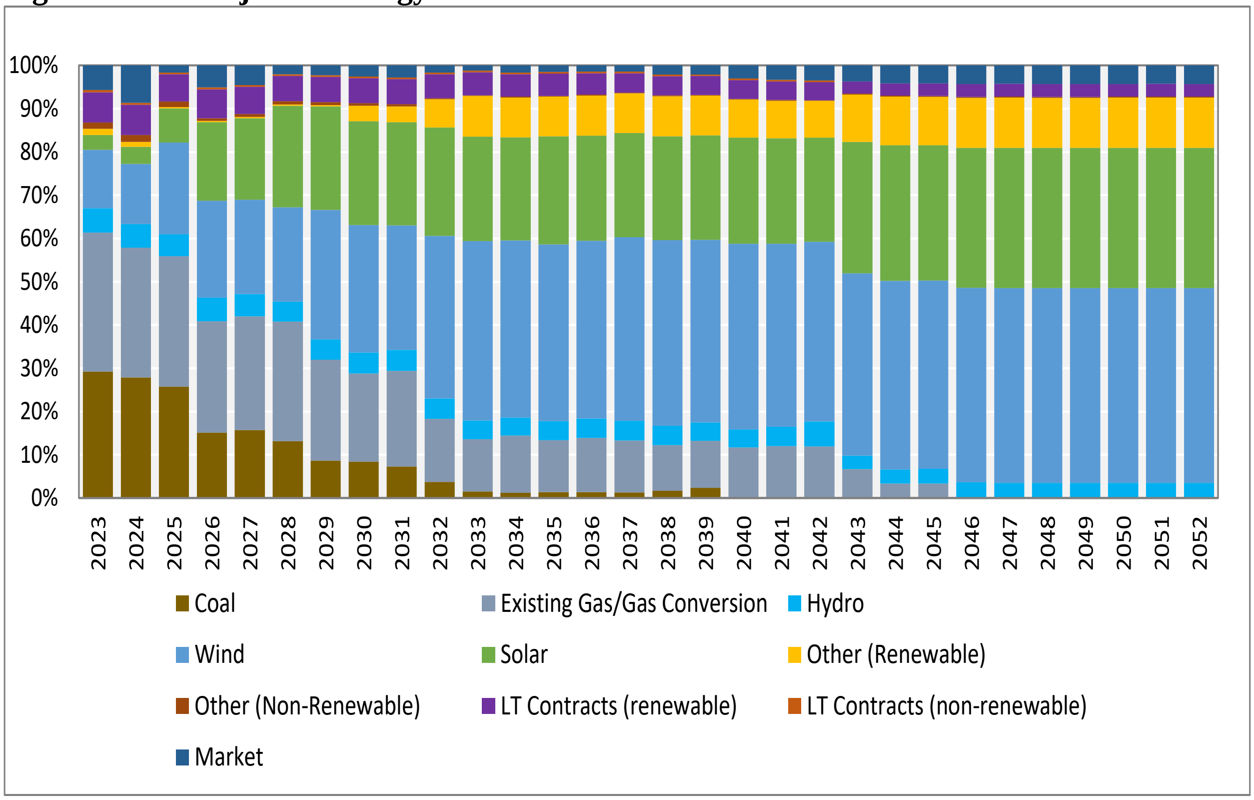
* Includes 13% Planning Reserve Margin, Sales and Non-Owned Reserves
** Includes the storage component of wind and solar collocated with storage
*** Includes retirements, and gas conversions

Figure 9.54 and Figure 9.55 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[4] On an

[4]The projected PacifiCorp 2021 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future

energy basis, coal generation drops to 25 percent by 2027, falls to 9 percent by 2032, and declines to only 1 percent by the end of the planning period. On a capacity basis, coal resources drop to 18 percent by 2027, fall to 11 percent by 2032, and decline to 3 percent by the end of the planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources, DSM resources, and to a smaller extent later in the plan, non-emitting peaker resources.

Figure 9.54 – Projected Energy Mix with Preferred Portfolio Resources



years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2021 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Figure 9.55 – Projected Energy Mix with Preferred Portfolio Resources

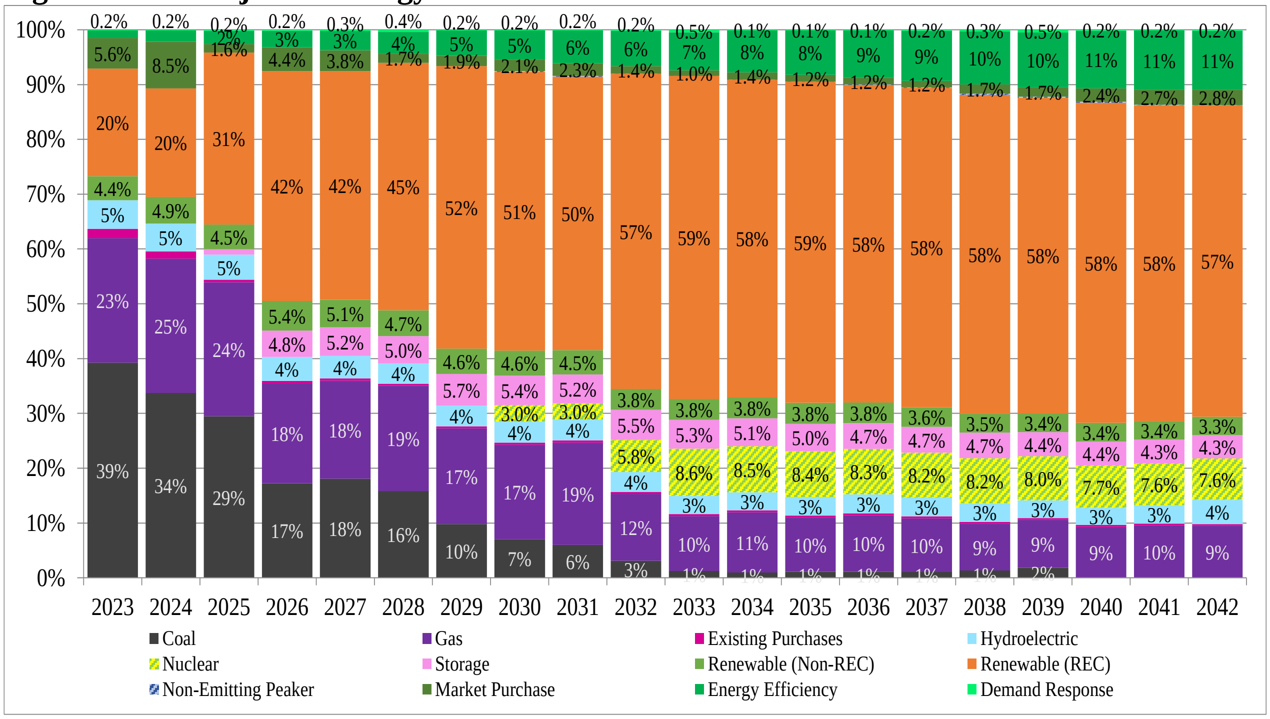


Figure 9.56 – Projected Energy Mix with Preferred Portfolio Resources

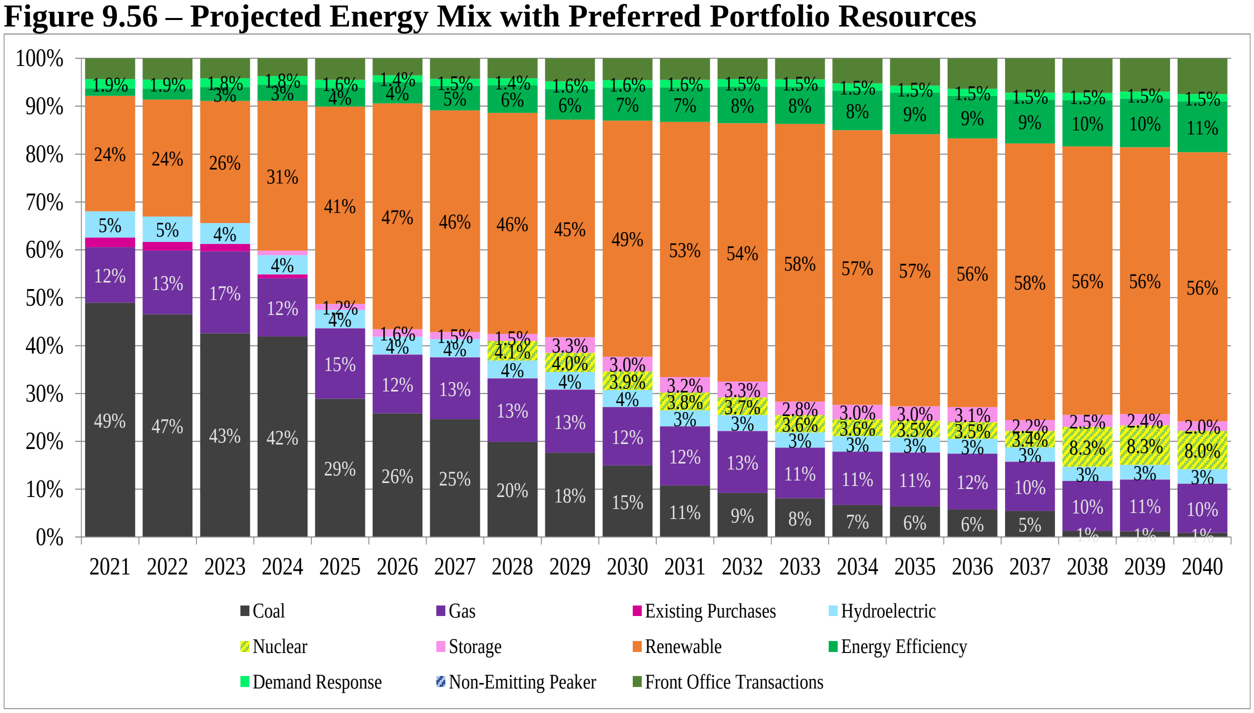


Figure 9.57 – Projected Capacity Mix with Preferred Portfolio Resources

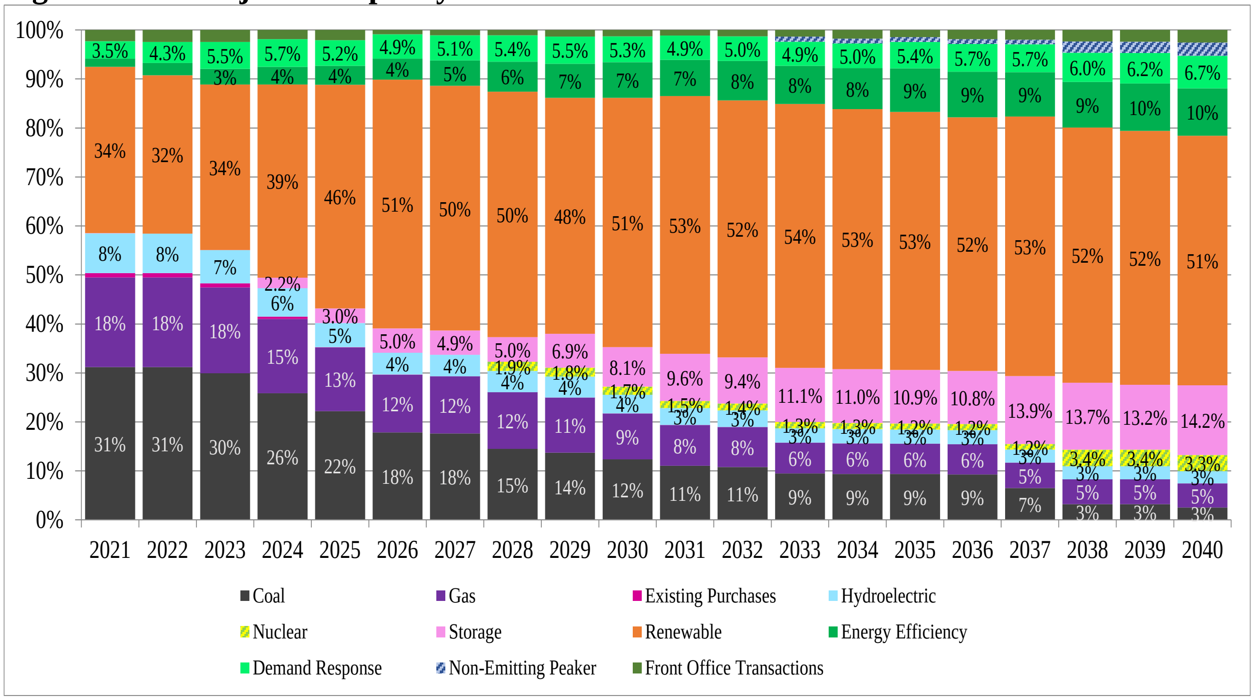


Figure 9.58 – Projected Generation Mix with Preferred Portfolio Resources Reflective of Renewable Claims

Firgure 9.58 shows the generation profile from the preferred portfolio consistent with Figures 9.45 and 9.46 where renewable energy without accompanying RECs is reflected as "unspecified". The RECs associated with "Unspecified" generation were not acquired under current ctonract terms, are claimed by customers under renewable energy terrifs or under contract for sale. The projection does not make assumptions around future REC sales or use of RECs form proxy resources.

Detailed Preferred Portfolio

Table 9.20 provides line-item detail of PacifiCorp's 2023 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 20-year planning horizon. Table 9.21 shows line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 20-year planning horizon. Table 9.22 shows line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the twenty-year planning horizon.

Table 9.20 – PacifiCorp's 2023 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	987	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	166	195	231	52	41	52	52	52	52	52	52	62	46	85	364
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	547	535	587	158	83	53	66	65	48	120	132	182	231	252	595
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,729**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**3,897**	**1,965**	**1,505**	**4,159**	**809**	**234**	**287**	**739**	**1,306**	**(1,095)**	**373**	**(166)**	**416**	**763**	

Table 9.1 – Preferred Portfolio Summer Capacity Load and Resource Balance (2023-2032)

East	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Thermal	5,271	5,056	4,873	4,893	4,857	4,523	4,191	4,332	4,454	3,886
Hydroelectric	87	70	65	65	65	62	60	62	64	59
Renewable	771	648	541	460	480	484	405	412	388	376
Storage	1	1	1	1	1	1	1	1	1	1
Purchase	104	100	31	27	26	23	22	22	23	21
Qualifying Facilities	834	983	576	375	358	329	285	296	275	265
Sale	(21)	0	0	0	0	0	0	0	0	0
East Existing Resources	**7,047**	**6,857**	**6,087**	**5,821**	**5,786**	**5,422**	**4,963**	**5,125**	**5,205**	**4,608**
Market Purchases	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	386	397	368
Wind	10	58	440	367	381	444	667	703	699	965
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	546	801	593	351	331	801	655	683	611	795
Solar+Storage	0	0	1,366	2,685	2,523	2,310	2,250	2,414	2,349	2,340
Storage	0	0	0	0	0	598	691	745	755	754
Nuclear	0	0	0	0	0	0	0	335	342	652
Geothermal	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**556**	**859**	**2,399**	**3,403**	**3,235**	**4,154**	**4,264**	**5,265**	**5,154**	**5,874**
East Total Resources	**7,603**	**7,717**	**8,486**	**9,224**	**9,022**	**9,576**	**9,227**	**10,390**	**10,359**	**10,482**
Load	7,485	7,720	7,889	7,886	8,074	8,406	8,376	8,516	8,731	8,849
Private Generation	(83)	(118)	(157)	(200)	(248)	(301)	(263)	(311)	(364)	(418)
Existing - Demand Response	(159)	(166)	(132)	(112)	(107)	(98)	(93)	(97)	(96)	(87)
New Demand Response	(0)	(2)	(15)	(19)	(33)	(33)	(32)	(35)	(38)	(35)
Existing - Energy Efficiency	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
New Energy Efficiency	(71)	(99)	(162)	(231)	(321)	(412)	(484)	(581)	(739)	(848)
East Total obligation	**7,101**	**7,265**	**7,353**	**7,254**	**7,296**	**7,492**	**7,434**	**7,423**	**7,424**	**7,391**
East Reserve Margin	7%	6%	15%	27%	24%	28%	24%	40%	40%	42%
West										
Thermal	631	603	575	585	579	560	542	468	481	446
Hydroelectric	604	535	515	525	520	502	486	503	517	480
Renewable	120	118	91	87	85	84	80	82	83	70
Purchase	1	1	1	1	1	1	1	1	1	1
Storage	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	255	291	200	150	139	128	110	115	111	105
Sale	(75)	(54)	(51)	(50)	(50)	(48)	(43)	(46)	(47)	(42)
West Existing Resources	**1,536**	**1,493**	**1,331**	**1,297**	**1,274**	**1,226**	**1,176**	**1,123**	**1,148**	**1,061**
Market Purchases	2,832	3,111	2,789	522	396	0	735	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	30	29	28	30	30	288
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	93	114	72	46	43	38	33	34	30	29
Solar+Storage	0	0	14	1,378	1,801	1,650	1,368	1,462	1,438	1,441
Storage	0	0	0	151	237	760	730	785	796	792
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**2,925**	**3,225**	**2,874**	**2,096**	**2,506**	**2,478**	**2,894**	**2,311**	**2,293**	**2,550**
West Total Resources	**4,461**	**4,718**	**4,204**	**3,393**	**3,780**	**3,704**	**4,070**	**3,434**	**3,440**	**3,610**
Load	3,656	3,863	4,067	4,140	4,309	4,481	4,655	4,711	4,873	4,913
Private Generation	(25)	(37)	(51)	(67)	(83)	(101)	(85)	(100)	(117)	(135)
Existing - Demand Response	(8)	(7)	(7)	(6)	(6)	(5)	(5)	(5)	(5)	(5)
New Demand Response	0	(2)	(13)	(17)	(25)	(26)	(27)	(28)	(30)	(28)
Existing - Energy Efficiency	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)
New Energy Efficiency	(37)	(66)	(107)	(125)	(150)	(182)	(193)	(228)	(269)	(277)
West Total obligation	**3,556**	**3,719**	**3,858**	**3,894**	**4,014**	**4,136**	**4,315**	**4,319**	**4,421**	**4,438**
West Reserve Margin	25%	27%	9%	-13%	-6%	-10%	-6%	-20%	-22%	-19%
System										
Total Resources	12,064	12,435	12,691	12,617	12,802	13,280	13,297	13,825	13,799	14,092
Obligation	10,657	10,984	11,211	11,148	11,309	11,628	11,749	11,742	11,844	11,829
Planning Reverve Margin (13%)	1,385	1,428	1,457	1,449	1,470	1,512	1,527	1,526	1,540	1,538
Obligation + Reserves	12,042	12,412	12,669	12,597	12,779	13,139	13,277	13,268	13,384	13,367
System Position	22	23	22	20	22	141	20	557	415	725
Reserve Margin	**13%**	**13%**	**13%**	**13%**	**13%**	**14%**	**13%**	**18%**	**17%**	**19%**

Table 9.21 – Preferred Portfolio Summer Capacity Load and Resource Balance (2033-2042)

East	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	2,555	2,347	2,338	2,759	2,198	1,100	1,111	710	748	827
Hydroelectric	53	53	52	62	57	47	47	41	43	47
Renewable	364	356	332	419	346	300	305	261	257	263
Storage	1	0	0	0	0	0	0	0	0	0
Purchase	19	19	19	22	20	16	16	14	15	17
Qualifying Facilities	241	241	225	261	192	173	170	151	152	154
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**3,232**	**3,017**	**2,966**	**3,523**	**2,812**	**1,636**	**1,649**	**1,178**	**1,215**	**1,308**
Market Purchases	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	327	327	326	384	524	425	430	374	394	435
Wind	951	944	867	1,093	970	914	909	798	812	832
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	755	830	757	906	709	658	659	606	592	574
Solar+Storage	2,328	2,569	2,573	2,669	2,530	2,494	2,497	2,478	2,475	2,484
Storage	1,016	1,151	1,180	1,168	1,550	1,551	1,559	1,573	1,576	1,591
Nuclear	916	965	973	1,067	1,018	907	914	855	878	929
Geothermal	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**6,293**	**6,786**	**6,676**	**7,287**	**7,300**	**6,949**	**6,968**	**6,683**	**6,726**	**6,846**
East Total Resources	**9,526**	**9,803**	**9,642**	**10,810**	**10,112**	**8,584**	**8,617**	**7,861**	**7,941**	**8,154**
Load	8,981	9,134	9,301	9,541	9,680	9,844	9,987	10,160	10,340	10,565
Private Generation	(472)	(522)	(571)	(620)	(668)	(716)	(763)	(808)	(856)	(902)
Existing - Demand Response	(76)	(78)	(78)	(94)	(80)	(66)	(68)	(61)	(65)	(68)
New Demand Response	(30)	(30)	(30)	(36)	(33)	(42)	(44)	(39)	(41)	(46)
Existing - Energy Efficiency	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)	(70)
New Energy Efficiency	(931)	(1,023)	(1,096)	(1,205)	(1,368)	(1,437)	(1,529)	(1,592)	(1,638)	(1,612)
East Total obligation	**7,402**	**7,411**	**7,456**	**7,518**	**7,461**	**7,514**	**7,515**	**7,591**	**7,671**	**7,867**
East Reserve Margin	29%	32%	29%	44%	36%	14%	15%	4%	4%	4%
West										
Thermal	397	396	395	466	430	234	237	206	217	240
Hydroelectric	426	426	424	501	461	374	379	329	346	383
Renewable	67	68	64	80	65	56	62	54	56	56
Purchase	1	1	1	1	1	1	1	1	1	1
Storage	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	96	97	92	111	90	79	77	68	69	71
Sale	(38)	(38)	(37)	(43)	(40)	(34)	(34)	(29)	(30)	(33)
West Existing Resources	**950**	**949**	**939**	**1,115**	**1,007**	**711**	**722**	**629**	**658**	**716**
Market Purchases	135	0	0	0	0	1,361	1,352	2,478	2,513	2,523
NonEmitting Peaker	0	0	0	219	202	164	166	144	152	168
Wind	559	556	546	663	550	473	519	456	473	466
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	26	27	27	31	24	23	23	22	21	20
Solar+Storage	1,432	1,586	1,592	1,646	1,563	1,552	1,554	1,543	1,540	1,543
Storage	802	905	927	923	922	917	922	927	930	941
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**2,954**	**3,074**	**3,092**	**3,482**	**3,261**	**4,490**	**4,536**	**5,571**	**5,627**	**5,661**
West Total Resources	**3,903**	**4,023**	**4,031**	**4,597**	**4,268**	**5,201**	**5,258**	**6,200**	**6,285**	**6,378**
Load	4,992	5,070	5,147	5,230	5,320	5,400	5,481	5,575	5,667	5,807
Private Generation	(153)	(169)	(185)	(199)	(214)	(228)	(242)	(256)	(270)	(283)
Existing - Demand Response	(4)	(4)	(4)	(5)	(4)	(4)	(4)	(3)	(3)	(4)
New Demand Response	(25)	(25)	(25)	(30)	(27)	(27)	(28)	(25)	(26)	(29)
Existing - Energy Efficiency	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)	(31)
New Energy Efficiency	(313)	(337)	(343)	(369)	(406)	(440)	(429)	(423)	(434)	(485)
West Total obligation	**4,467**	**4,504**	**4,559**	**4,597**	**4,638**	**4,670**	**4,747**	**4,839**	**4,903**	**4,976**
West Reserve Margin	-13%	-11%	-12%	0%	-8%	11%	11%	28%	28%	28%
System										
Total Resources	13,429	13,826	13,673	15,407	14,380	13,785	13,875	14,062	14,226	14,532
Obligation	11,869	11,915	12,015	12,115	12,099	12,183	12,262	12,429	12,574	12,843
Planning Reverve Margin (13%)	1,543	1,549	1,562	1,575	1,573	1,584	1,594	1,616	1,635	1,670
Obligation + Reserves	13,412	13,464	13,577	13,689	13,672	13,767	13,856	14,045	14,209	14,513
System Position	18	361	96	1,718	708	18	18	17	18	19
Reserve Margin	**13%**	**16%**	**14%**	**27%**	**19%**	**13%**	**13%**	**13%**	**13%**	**13%**

Table 9.22 – Preferred Portfolio Winter Capacity Load and Resource Balance (2023-2032)

East	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Thermal	5,894	5,321	5,478	5,151	5,547	5,383	4,804	4,613	5,407	4,786
Hydroelectric	71	57	56	54	57	58	54	54	61	58
Renewable	790	999	877	827	921	682	568	585	604	618
Storage	1	1	1	1	1	1	1	1	1	1
Purchase	116	70	34	28	28	27	24	24	27	25
Qualifying Facilities	243	274	234	217	233	183	166	169	182	179
Sale	(23)	0	0	0	0	0	0	0	0	0
East Existing Resources	**7,093**	**6,721**	**6,679**	**6,279**	**6,786**	**6,333**	**5,617**	**5,445**	**6,280**	**5,667**
Market Purchases	453	615	317	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	28	430	482	463
Wind	11	107	728	705	783	700	1,003	1,111	1,234	1,711
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	90	143	121	108	123	140	121	124	116	162
Solar+Storage	0	3	726	1,561	1,504	1,313	1,463	1,472	1,477	1,608
Storage	0	0	0	0	0	480	619	624	629	683
Nuclear	0	0	0	0	0	0	16	340	381	759
Geothermal	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**555**	**867**	**1,891**	**2,373**	**2,410**	**2,633**	**3,251**	**4,100**	**4,320**	**5,386**
East Total Resources	**7,647**	**7,589**	**8,570**	**8,652**	**9,196**	**8,966**	**8,868**	**9,546**	**10,600**	**11,053**
Load	5,833	5,890	6,032	6,039	6,253	6,426	6,496	6,586	6,680	6,739
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	(68)	(63)	(59)	(48)	(49)	(46)	(41)	(41)	(47)	(44)
New Demand Response	(0)	(1)	(11)	(19)	(25)	(27)	(24)	(24)	(27)	(26)
Existing - Energy Efficiency	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)
New Energy Efficiency	(41)	(80)	(150)	(180)	(238)	(301)	(346)	(416)	(544)	(598)
East Total obligation	**5,684**	**5,706**	**5,772**	**5,752**	**5,901**	**6,011**	**6,045**	**6,065**	**6,021**	**6,031**
East Reserve Margin	35%	33%	48%	50%	56%	49%	47%	57%	76%	83%
West										
Thermal	745	707	687	672	701	698	655	563	630	606
Hydroelectric	749	692	655	642	670	680	637	637	714	684
Storage	0	0	0	0	0	0	0	0	0	0
Renewable	89	100	91	83	85	72	66	76	83	75
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	81	84	79	72	69	67	60	60	67	61
Sale	(80)	(58)	(55)	(53)	(56)	(48)	(43)	(45)	(50)	(46)
West Existing Resources	**1,586**	**1,526**	**1,459**	**1,417**	**1,470**	**1,471**	**1,377**	**1,292**	**1,445**	**1,381**
Market Purchases	1,057	1,436	739	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	18	17	15	17	24	219
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	6	7	7	6	6	3	2	3	3	2
Solar+Storage	0	0	7	841	1,086	975	896	904	912	983
Storage	0	0	0	132	202	623	661	665	676	727
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,063**	**1,443**	**753**	**979**	**1,313**	**1,618**	**1,574**	**1,590**	**1,615**	**1,932**
West Total Resources	**2,649**	**2,969**	**2,213**	**2,397**	**2,783**	**3,089**	**2,952**	**2,882**	**3,061**	**3,312**
Load	3,485	3,738	3,911	3,993	4,148	4,336	4,397	4,415	4,530	4,562
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing - Demand Response	0	0	0	(0)	0	0	0	(0)	(0)	(0)
New Demand Response	0	(15)	(24)	(24)	(27)	(30)	(27)	(26)	(30)	(28)
Existing - Energy Efficiency	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
New Energy Efficiency	(35)	(66)	(98)	(168)	(214)	(244)	(310)	(331)	(360)	(399)
West Total obligation	**3,421**	**3,628**	**3,759**	**3,771**	**3,878**	**4,033**	**4,031**	**4,027**	**4,111**	**4,104**
West Reserve Margin	-23%	-18%	-41%	-36%	-28%	-23%	-27%	-28%	-26%	-19%
System										
Total Resources	10,296	10,558	10,783	11,048	11,979	12,056	11,819	12,427	13,661	14,366
Obligation	9,104	9,334	9,532	9,523	9,779	10,044	10,076	10,092	10,133	10,135
Planning Reverve Margin (13%)	1,184	1,213	1,239	1,238	1,271	1,306	1,310	1,312	1,317	1,318
Obligation + Reserves	10,288	10,548	10,771	10,761	11,050	11,350	11,385	11,404	11,450	11,453
System Position	9	10	12	288	929	706	434	1,023	2,211	2,913
Reserve Margin	**13%**	**13%**	**13%**	**16%**	**23%**	**20%**	**17%**	**23%**	**35%**	**42%**

Table 9.2212 – Preferred Portfolio Winter Capacity Load and Resource Balance (2033-2042)

East	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Thermal	3,451	3,007	2,712	2,702	2,471	1,398	1,307	934	876	941
Hydroelectric	56	52	47	49	52	46	44	41	39	42
Renewable	501	491	466	535	507	397	358	364	327	337
Storage	1	0	0	0	0	0	0	0	0	0
Purchase	24	22	20	21	22	20	19	18	17	18
Qualifying Facilities	151	138	127	129	130	107	102	94	91	92
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**4,183**	**3,711**	**3,373**	**3,438**	**3,182**	**1,968**	**1,829**	**1,452**	**1,349**	**1,429**
Market Purchases	0	0	0	0	0	86	219	394	516	482
NonEmitting Peaker	444	416	375	412	613	540	516	484	451	485
Wind	1,419	1,395	1,315	1,529	1,563	1,281	1,154	1,180	1,104	1,124
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	121	108	111	113	108	80	76	75	81	61
Solar+Storage	1,546	1,846	1,859	1,891	1,873	1,868	1,904	1,922	1,940	1,954
Storage	883	1,069	1,076	1,094	1,434	1,443	1,474	1,487	1,498	1,518
Nuclear	1,063	1,083	1,017	1,055	1,088	1,007	989	956	921	966
Geothermal	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**5,476**	**5,916**	**5,753**	**6,094**	**6,679**	**6,305**	**6,334**	**6,497**	**6,511**	**6,590**
East Total Resources	**9,660**	**9,627**	**9,126**	**9,531**	**9,861**	**8,272**	**8,163**	**7,949**	**7,859**	**8,019**
Load	6,882	6,990	7,093	7,171	7,319	7,448	7,592	7,711	7,816	7,969
Private Generation	(0)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Existing - Demand Response	(42)	(39)	(35)	(37)	(39)	(34)	(34)	(32)	(30)	(32)
New Demand Response	(24)	(22)	(20)	(21)	(22)	(20)	(19)	(18)	(17)	(19)
Existing - Energy Efficiency	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)	(40)
New Energy Efficiency	(669)	(729)	(770)	(827)	(951)	(986)	(1,025)	(1,090)	(1,057)	(1,144)
East Total obligation	**6,106**	**6,159**	**6,226**	**6,244**	**6,266**	**6,367**	**6,472**	**6,530**	**6,671**	**6,733**
East Reserve Margin	58%	56%	47%	53%	57%	30%	26%	22%	18%	19%
West										
Thermal	575	541	490	514	522	325	307	291	271	291
Hydroelectric	657	616	556	581	614	541	517	484	451	485
Storage	0	0	0	0	0	0	0	0	0	0
Renewable	59	61	54	64	65	51	46	46	46	50
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	57	55	50	52	53	46	44	42	40	42
Sale	(41)	(39)	(36)	(40)	(39)	(34)	(30)	(30)	(27)	(29)
West Existing Resources	**1,308**	**1,234**	**1,116**	**1,172**	**1,216**	**929**	**885**	**834**	**782**	**841**
Market Purchases	0	0	0	0	0	201	511	919	1,204	1,124
NonEmitting Peaker	0	0	24	224	237	208	199	187	174	187
Wind	356	350	312	366	363	302	276	269	270	302
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	2	2	2	1	2	2	1	1	1	2
Solar+Storage	954	1,148	1,154	1,174	1,164	1,165	1,188	1,201	1,211	1,224
Storage	709	848	850	866	859	861	877	883	887	901
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**2,022**	**2,349**	**2,342**	**2,631**	**2,624**	**2,739**	**3,054**	**3,461**	**3,747**	**3,740**
West Total Resources	**3,330**	**3,583**	**3,458**	**3,803**	**3,840**	**3,669**	**3,938**	**4,295**	**4,530**	**4,581**
Load	4,607	4,654	4,702	4,772	4,830	4,878	4,943	4,995	5,054	5,132
Private Generation	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Existing - Demand Response	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
New Demand Response	(27)	(25)	(23)	(24)	(25)	(22)	(21)	(20)	(19)	(21)
Existing - Energy Efficiency	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)	(29)
New Energy Efficiency	(426)	(469)	(506)	(581)	(597)	(634)	(663)	(648)	(719)	(671)
West Total obligation	**4,124**	**4,130**	**4,143**	**4,137**	**4,177**	**4,192**	**4,228**	**4,297**	**4,285**	**4,410**
West Reserve Margin	-19%	-13%	-17%	-8%	-8%	-12%	-7%	0%	6%	4%
System										
Total Resources	12,990	13,210	12,585	13,334	13,701	11,941	12,101	12,244	12,389	12,600
Obligation	10,230	10,289	10,369	10,381	10,444	10,558	10,700	10,827	10,956	11,142
Planning Reverve Margin (13%)	1,330	1,338	1,348	1,350	1,358	1,373	1,391	1,408	1,424	1,448
Obligation + Reserves	11,560	11,626	11,717	11,731	11,801	11,931	12,092	12,235	12,380	12,591
System Position	1,430	1,584	867	1,603	1,900	10	10	9	9	9
Reserve Margin	**27%**	**28%**	**21%**	**28%**	**31%**	**13%**	**13%**	**13%**	**13%**	**13%**

Washington Scenarios

As described in Chapter 8, Washington's CETA legislation indicates four key studies and sensitivities be analyzed:

- **W-10 CETA**
- **W-11 Climate Change Counterfactual**
- **W-12 Maximum Customer Benefit**
- **P-SC Alternative Lowest Reasonable Cost**

WAC 480-100-620(11)(a) specifically requires the utility to demonstrate how the long-range integrated resource plan expects to achieve clean energy transformation standards (WAC 480-100-610 (1) through (3)), and (j), to incorporate the social cost of greenhouse gas emissions as a cost adder as specific in RCW 19.280.030(3). These specific requirements of an IRP are unique to Washington and the Company must analyze the Washington-compliant portfolio against the system-optimized preferred portfolio to avoid imposing impacts on non-Washington customers.

W-10 CETA is the optimized portfolio developed under the SC price policy and is projected to meet all CETA clean energy targets through 2030 and 2045, specifically meeting all requirements set out in WAC 480-100-620(11).[5] The W-10 CETA portfolio is developed for Washington, based on a starting point of the Alternative Lowest Reasonable Cost, P-SC. Discussion of CETA compliance and development of the portfolio to meet CETA targets can be found in Volume II, Appendix O.

In this section, PacifiCorp discusses the W-10 CETA portfolio selections and each of the additional scenario outcomes relative to the W-10 portfolio and the system optimized preferred portfolio P-MM dispatched under SC.

W-10 CETA

The W-10 CETA portfolio is nearly identical to the P-SC portfolio: the portfolio is optimized across existing coal and gas resources and new proxy resources under the SC price policy assumption, but includes incremental resources to Washington customers for CETA-compliance in 2030 and 2031.

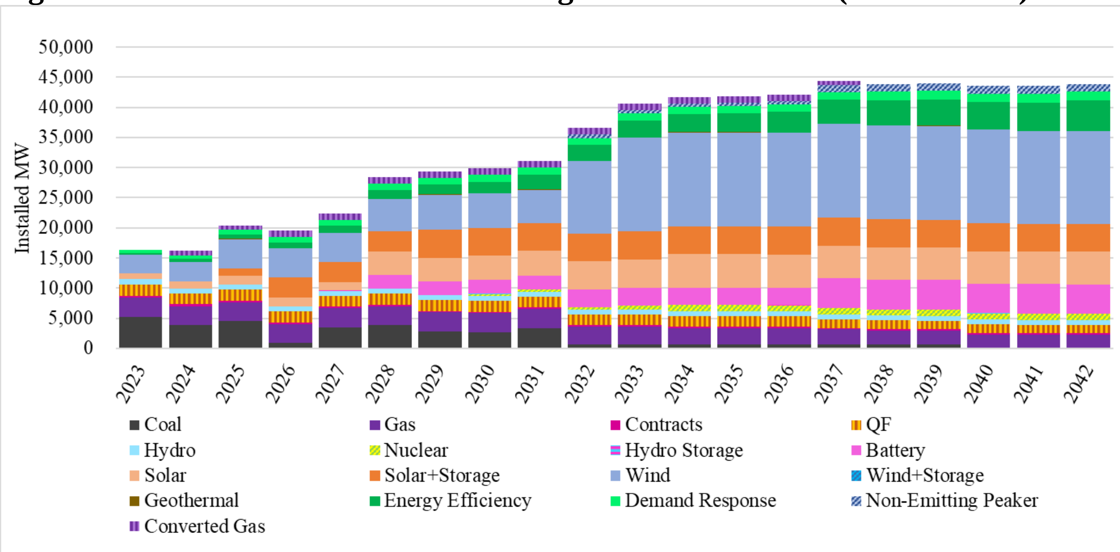
The W-10 CETA system portfolio results in 13,081 MW of new wind capacity, 8,625 MW of solar, and 9,171 MW of storage co-located with renewables, where 1,184 MW of that storage capacity is long-duration battery. The new solar and wind capacity includes 120 MW of small-scale wind capacity and 120 MW of small-scale solar capacity located in Yakima, Washington that were added as incremental resources needed for CETA compliance in 2030 onwards. The small-scale resources do incur higher build costs than utility-scale renewables, but do not require additional transmission capacity to generate.

Additionally, the portfolio selects 1,240 MW of non-emitting peakers, 1,500 MW of advanced nuclear technology, and 35 MW of pumped hydro. There are no new emitting resources added to the portfolio over the planning horizon. In the W-10 CETA portfolio all coal-fueled resources are

[5] W-10, the CETA-compliant portfolio, is also considered the Clean Energy Implementation Plan (CEIP) Portfolio.

retired before 2040 and all gas-fueled resources by 2048, but most notably for Washington customers specifically is the conversion of Jim Bridger coal units 1 and 2 to gas-fired in 2024.[6] For demand-side management resources in Washington there is a selection of 206.2 MW of energy efficiency and 104.5 MW of demand-response in total across the period. Cumulative portfolio resource additions for system-wide results for W-10 CETA are shown in Figure 9.59.

Figure 9.59 – Cumulative Portfolio Changes for W-10 CETA (all resources)

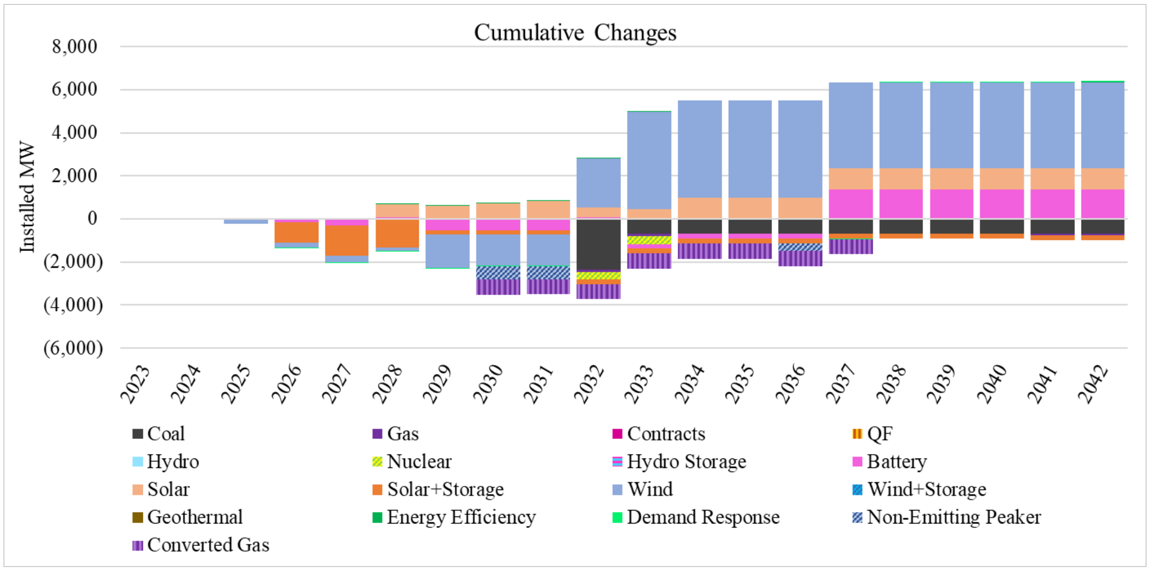


The W-10 CETA portfolio results in a risk-adjusted PVRR of $55.52 billion. For contrast, the W-10 CETA portfolio is an estimated $18.40 billion more expensive than the system preferred portfolio, P-MM. The cost differential is partly a result of the the SC price policy assumption versus the medium carbon price. When the preferred portfolio is run under the SC price policy in operations (after the optimal portfolio was developed under the medium carbon price scenario) the portfolio performs less efficiently, resulting in a PVRR(d) of $58.24 billion, which is almost $3 billion more expensive than W-10.

In terms of resource differences between W-10 CETA and P-MM, the CETA-compliant portfolio adds 5,763 MW more capacity across the planning horizon. The cumulative differences in the W-10 CETA portfolio relative to P-MM are shown in Figure 9.60

[6] Thermal retirements are fully optimized at the system level in the W-10 portfolio while the model remains agnostic about any state-specific allocations of resources. To the extent that an early thermal retirement is triggered under the SC price-policy assumption only, and is not cost-allocated to Washington customers, the retirement may not be considered optimal for the rest of the system.

Figure 9.60 – Cumulative Portfolio Resource Changes W-10 CETA compared to the 2023 IRP Preferred Portfolio



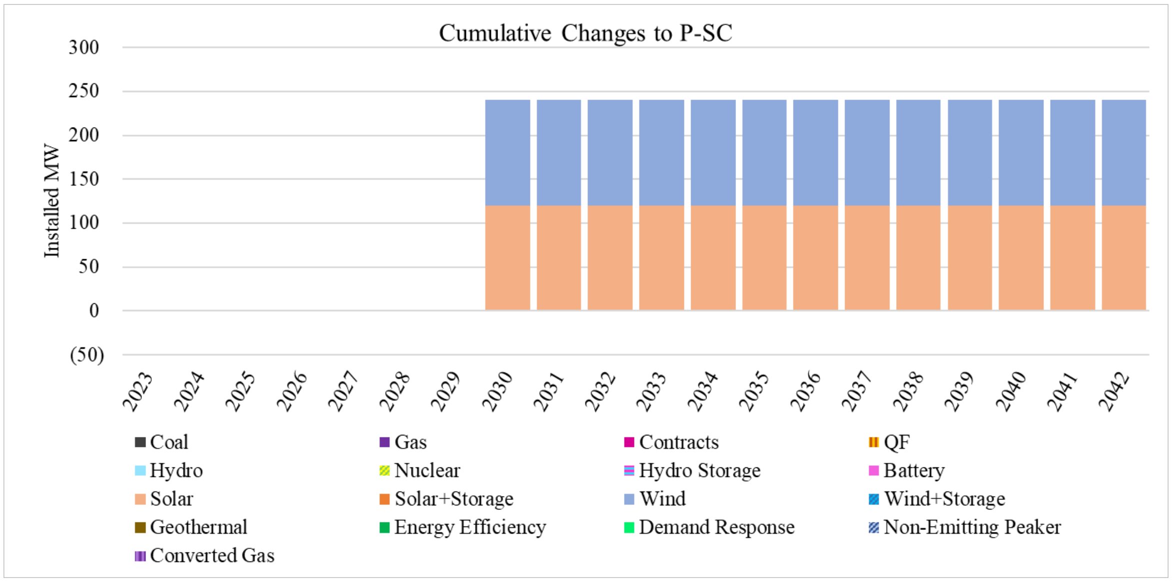
Alternative Lowest Reasonable Cost

WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's directives and must include the social cost of greenhouse gases (SC) in the resource acquisition decision. Thus, the system-optimized portfolio developed under the SC price-policy assumption, P-SC, is the Alternative Lowest Reasonable Cost scenario that would have resulted but not for CETA. This portfolio serves as the basis for assessing Washington-allocated energy and development of the CETA-compliant portfolio as discussed in Volume II, Appendix O (Washington Two-Year Progress Report Additional Elements).

The W-10 CETA-compliant portfolio is $10 million cheaper on a PVRR(d) basis, as compared to the Alternative Lowest Reasonable Cost portfolio. Despite the incurred incremental build costs in the W-10 CETA portfolio due to the additional small-scale wind and solar capacity, there is a positive offset in cost from a reduction in greenhouse gas emissions and coal fuel – a direct result of increased renewable generation. These costs are on a system risk-adjusted PVRR basis, however, and are not necessarily reflective of Washington-allocated cost impacts.

Figure 9.61 shows the cumulative portfolio resource changes of W-10 CETA as compared to P-SC. The figure depicts the incremental small-scale wind and solar resources that were added to the P-SC portfolio to meet CETA clean energy targets in 2030 and 2031.

Figure 9.61 – Cumulative Portfolio Resource Changes W-10 CETA compared to P-SC Alternative Lowest Reasonable Cost



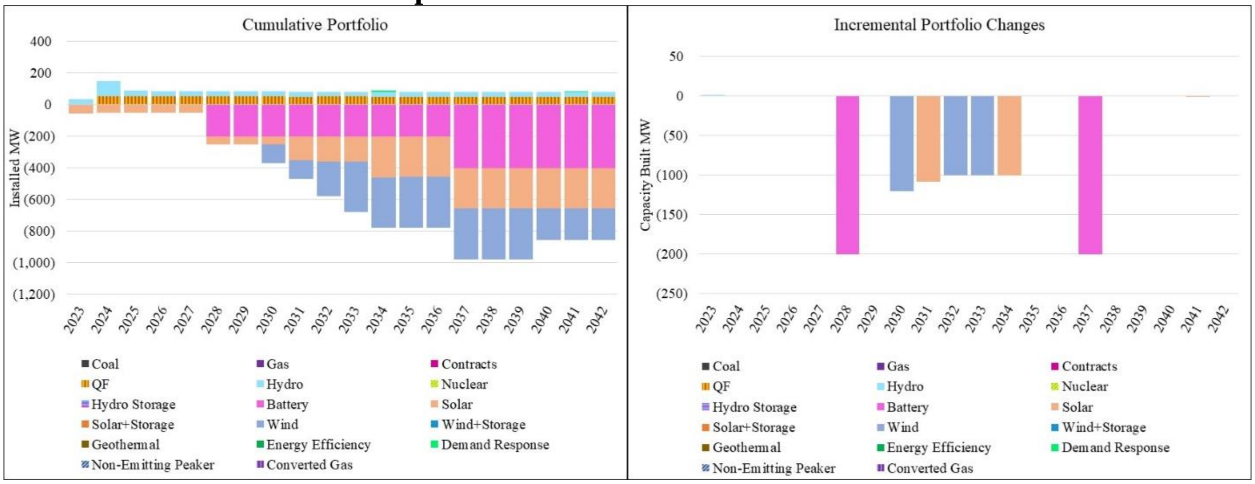
Climate Change Counterfactual

The base 2023 IRP includes an updated load forecast to incorporate regional studies on potential temperature change (and associated impact to demand and energy). Relative to the 20-year normal scenario, the base 2023 IRP results in summer peaks being higher by approximately 30 MW (<1% higher) over the 2023-2027 timeframe. By 2042, summer peaks are projected to be 474 MW (2.7%) higher than the 2021 IRP Base. Higher winter temperatures result in less heating load, which are driving lower winter peaks. By 2040, winter peaks are projected to be 259 MW (3.1%) higher than the 20-year normal scenario. Please see Appendix A for additional detail regarding how climate change is incorporated into the base 2023 IRP.

The scenario also includes analysis of impacts from climate change (precipitation, streamflow, etc.) on hydroelectric generating facilities on the Lewis River, North Umpqua River, and Rogue River systems. The impact analysis projects seasonally lower natural streamflows during summer months and higher winter season streamflows. Over the 20-year planning period, the analysis indicates that annual streamflow volumes for the North Umpqua River and Rogue River remain relatively constant, while annual streamflow volume for the Lewis River is projected to increase over the 20-year planning period by up to about 4%. In addition to the changes in hydro capacity due to climate change, the decrease in load against the base load forecast led to a reduction in resource selections. This case selected 400 MW less storage, and just over 200 MW less solar and wind each.

Compared to W-10 CETA portfolio, the exclusion of climate change temperatures and precipitation effects increases system risk-adjusted PVRR by $858 million. The cumulative portfolio resource changes in the no climate change portfolio compared to W-10 CETA are shown in Figure 9.62.

Figure 9.62 – Cumulative and Incremental Portfolio Resource Changes, Climate Change Counterfactual Portfolio Compared to W-10 CETA

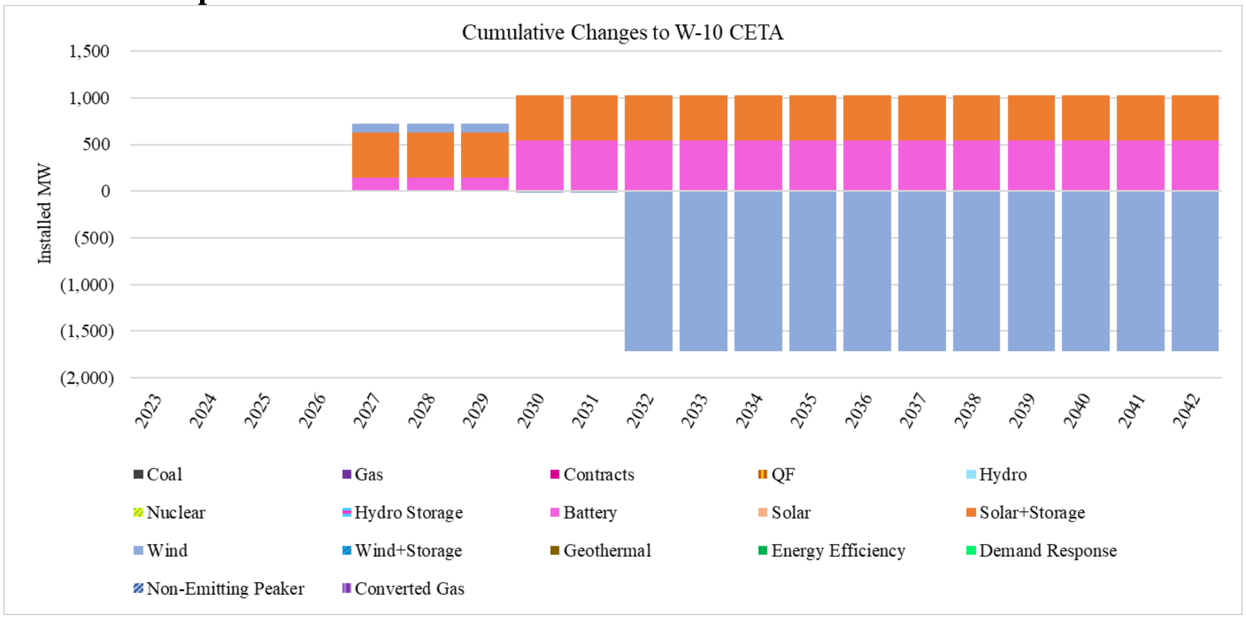


Maximum Customer Benefit

The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and is assumed to be CETA-compliant. All available Washington energy efficiency and demand response is added, beyond what was already selected in the W-10 CETA portfolio. The Maximum Customer Benefit portfolio results in $2.77 billion more on a PVRR(d) basis as compared to W-10 CETA portfolio. The cumulative portfolio resource changes in the Maximum Customer Benefit portfolio relative to W-10 CETA are shown in Figure 9.63.

As a result of the requirement to remove high voltage transmission options, over 1,500 MW of wind located in Walla Walla is forced to come out of the portfolio. This wind is highly beneficial to the system as a whole, and is a major contributor to the higher costs. The removal of these lines also necessitates additional storage and solar to be built throughout the system as resources which would have been able to reach the rest of the west side of the system now may not do so as effectively. This reduction in system flexibility also contributes to the higher cost.

Figure 9.63 – Cumulative Portfolio Resource Changes, Maximum Customer Benefit Portfolio Compared to W-10 CETA Portfolio



The portfolios run under the SC price policy assumption are shown in Table 9.23. All portfolios shown in the table, except the first row (the preferred portfolio) were developed under the SC price policy assumption in the capacity expansion decision, per Washington rule. The system preferred portfolio was developed under the medium carbon price assumption, but is shown here dispatched with SC in operations, for comparison. The W-10 CETA portfolio is the best performing portfolio scenario across the SC portfolios and serves as the basis for the Washington Clean Energy Implementation Plan (CEIP) as described in Volume II, Appendix O.

Table 9.23 – All Washington-required portfolios and portfolios run under the SC price policy assumption

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - SC	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P-MM	58,238	$2,722	4	58,192	$2,885	5	0.0020%	-0.00003%	2	332,257	12,250	5
P-SC	55,525	$10	2	55,329	$22	2	0.0020%	0.00000%	5	321,100	1,094	4
W-10 SC CETA	55,516	$0	1	55,307	$0	1	0.0020%	0.00000%	4	320,006	0	3
W-11 CETA No Climate	56,374	$859	3	56,142	$835	3	0.0019%	-0.00013%	1	318,685	-1,322	2
W-12 CETA Max Benefit	58,279	$2,763	5	58,111	$2,804	4	0.0020%	0.00000%	3	310,798	-9,208	1

Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the portfolio-development process that supports selection of the preferred portfolio, sensitivity cases will be completed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. These sensitivity cases are useful in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risk.

Table 9.24 lists additional sensitivity studies to be performed for the 2023 IRP. To isolate the impact of a given planning assumption, all sensitivity cases will be evaluated with the preferred portfolio.

Table 9.24 – Summary of Additional Sensitivity Cases

Case	Description	Risk-Adjusted PVRR ($m)	Load	Private Gen	CO_2 Policy
S-01	High Load	High	Low	Optimized	Medium gas / Medium CO_2
S-02	Low Load	Low	High	Optimized	Medium gas / Medium CO_2
S-03	1 in 20 Load Growth	1 in 20	Base	Optimized	Medium gas / Medium CO_2
S-04	20-year Normal	20yr Normal	Base	Optimized	Medium gas / Medium CO_2
S-05	High Private Generation	Base	High	Optimized	Medium gas / Medium CO_2
S-06	Low Private Generation	Base	Low	Optimized	Medium gas / Medium CO_2
S-07	Business Plan	Base	Base	Align first three years	Medium gas / Medium CO_2
S-08	New Load	Flat Load Increase	Base	Optimized	Medium gas / Medium CO_2
W-10	CETA	Base	Base	Added for CETA	WA resources under SC
W-11	Climate Change Counterfactual	No climate change	Base	Optimized	WA resources under SC
W-12	Max Customer Benefit	Base	Base	Modified	WA resources under SC

PacifiCorp will file a supplemental filing to its 2023 IRP filing that includes discussion and results of these sensitivities. The supplemental filing will also be posted to PacifiCorp's IRP webpage at the following location: www.pacificorp.com/energy/integrated-resource-plan.

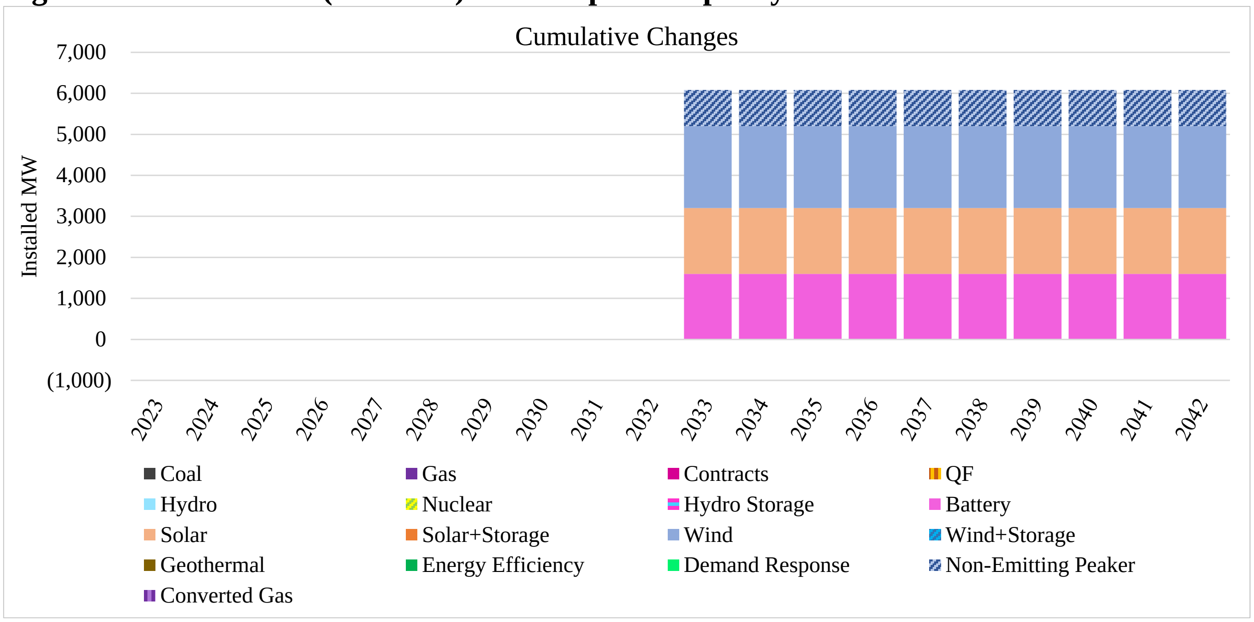
New Load Sensitivity (S-08)

shows the PVRR impacts of the S-08 sensitivity relative to preferred portfolio. Higher loads result in increased resource requirements which translate into higher system costs. Table 9.25 summarizes the portfolio impacts. The new loads, approximate 3000 GW, in 2033 required the addition of wind, solar, battery and non-emitting peakers. Transmission was required to integrate renewables are Boardman to Heminway 2, Gateway South 2, D3-2, and D2-3, Segment E and Segment E 2 In combination, this resulted in higher fixed costs offset by lower fuel costs, lower emission costs, and lower market purchases. CO_2 emissions over the study period decreased by 19 million tons.

Table 9.25 – Risk-Adjusted PVRR (Benefit)/Cost of S-01 vs. P-MM

Medium Gas - Medium CO_2 ($ Million)		
P-MM	**S-08**	**(Benefit) / Cost Relative to P-MM**
$37,305	$40,846	$3,541

Figure 9.64 – Increase/(Decrease) in Nameplate Capacity of S-08 Relative to



Additional CCUS Sensitivities

Dave Johnston Unit 2 Converts to CCUS in 2028

The DJ2 CCUS portfolio is a variant of the preferred portfolio that forces a CCUS retrofit on Dave Johnston Unit 2 in 2028 to enable the project to qualify for existing tax credits. When this variant is compared to the preferred portfolio, changes in proxy resources and system costs driven by the CCUS retrofit can be isolated. Because CCUS was not selected as a least-cost resource option in the preferred portfolio, this variant was produced to evaluate a means to comply with Wyoming House Bill 200 (HB 200). HB 200 was passed by the Wyoming Legislature in March 2020, and it requires the Wyoming Public Service Commission to establish a standard that specifies a percentage of electricity that must be generated from coal-fired generation using carbon capture technology by 2030, subject to an incremental cost limitation of 2% of Wyoming customers' total bill to comply with the standard.

For modeling purposes, PacifiCorp chose to force a CCUS retrofit (amine based post-combustion + enhanced oil recovery) at Dave Johnston Unit 2 for the following reasons:

- There are no complications with co-ownership as would be the case with Wyodak or the Jim Bridger units
- Expectation of higher costs associated with necessary inlet NO_X and SO_2 controls relative to Dave Johnston Units 2
- Installation of CCUS at Dave Johnston Unit 2 would be expected to meet preliminary HB 200 targets

This modeling assumption does not mean PacifiCorp has determined Dave Johnston Unit 2 is the only site for a CCUS retrofit. As described in the 2023 IRP action plan, PacifiCorp is engaged in a request for expressions of interest process and has issued a request for proposals that will help identify candidates for potential CCUS retrofits and help refine cost-and-performance assumptions.

The installation of CCUS in 2028 replaces the coal unit. The CCUS extends the life of Dave Johnston Unit 2 to year end 2039 with a retrofit installed. There is a net reduction of capacity due to the parasitic load associated with the carbon capture equipment.[7]

Figure 9.65 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when CCUS is installed on Dave Johnston Unit 2 in 2028. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2039, the PVRR(d) shows that the portfolio with CCUS installed on Dave Johnston Unit 2 project is $514 million higher cost than the preferred portfolio.

When the CCUS retrofit is installed in 2028, the carbon capture technology increases the costs associated with Dave Johnston Unit 2. This shows up as increased fixed costs for coal and gas resources in the chart at left. This is partially offset by reduced emissions costs.

[7] Upon installation of the carbon capture equipment, Dave Johnston Unit 2's rating is 76 MW. As a coal-fired facility without carbon capture equipment, Dave Johnston Unit 2's rating is 106 MW.

Figure 9.65 – Increase /(Decrease) in System Costs when CCUS is Installed on Dave Johnston Unit 2 in 2028.

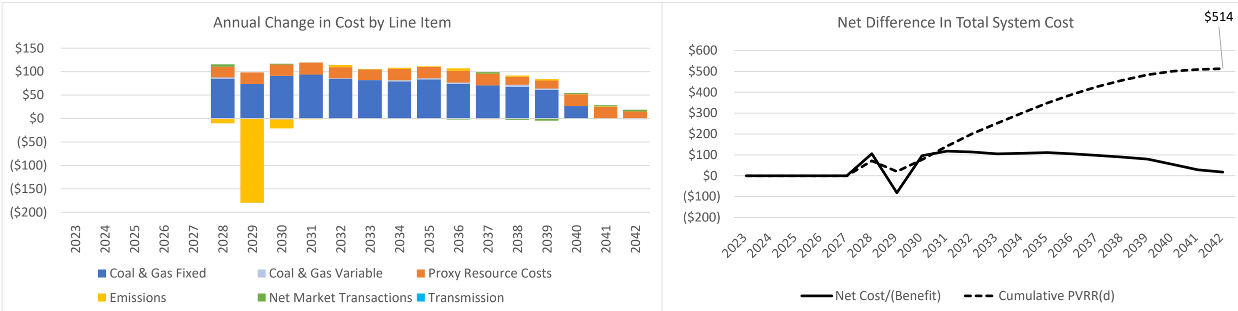


Figure 9.65 summarizes the PVRR(d) of the P20-DJ2 CCUS portfolio relative to the preferred portfolio under a range of different price-policy scenarios. The portfolio that includes the CCUS retrofit at Dave Johnston Unit 2 is higher cost than the preferred portfolio across each of the price-policy scenarios. This trend holds true for both the ST PVRR and the risk-adjusted PVRR results. Both portfolios, as measured by ENS, are very reliable. Emissions are slightly lower when CCUS is installed on Dave Johnston Unit 2. The magnitude of the increased cost in the portfolio that includes a CCUS retrofit on Dave Johnston Unit 2 in 2028, which would be situs-assigned to Wyoming customers, is expected to exceed the cost containment language set forth in HB 200, and for this reason, it is not included in the preferred portfolio. Nonetheless, PacifiCorp recognizes that this analysis is driven by a wide range of assumptions specific to the cost and commercial structure of CCUS opportunities. Consequently, PacifiCorp has established an action plan with a CCUS action item to continue with the on-going request for expressions of interest process and to proceed with a request for proposals process that will help identify potential sites, costs, and commercial structures that will allow us to update this analysis after the 2023 IRP.

Dave Johnston Unit 4 Converts to CCUS in 2028 Variant (DJ4 CCUS)

The DJ4 CCUS portfolio is a variant of the preferred portfolio that forces a CCUS retrofit on Dave Johnston Unit 4 in 2028 to enable the project to qualify for existing tax credits. When this variant is compared to the preferred portfolio, changes in proxy resources and system costs driven by the CCUS retrofit can be isolated. Because CCUS was not selected as a least-cost resource option in the preferred portfolio, this variant was produced to evaluate a means to comply with Wyoming House Bill 200 (HB 200). HB 200 was passed by the Wyoming Legislature in March 2020, and it requires the Wyoming Public Service Commission to establish a standard that specifies a percentage of electricity that must be generated from coal-fired generation using carbon capture technology by 2030, subject to an incremental cost limitation of 2% of Wyoming customers' total bill to comply with the standard.

For modeling purposes, PacifiCorp chose to force a CCUS retrofit (amine based post-combustion + enhanced oil recovery) at Dave Johnston Unit 4 for the following reasons:

- There are no complications with co-ownership as would be the case with Wyodak or the Jim Bridger units
- CCUS at Dave Johnston Unit 4 would not require a new lined coalcombustion residual impoundment as would be the case at the Naughton coal units
- Expectation of lower costs associated with necessary inlet NO_X and SO_2 controls relative to Dave Johnston Units 1 and 2
- Dave Johnston Unit 3 has a federal closure commitment under EPA's regional haze rule. Installation of CCUS at Dave Johnston Unit 4 would be expected to meet preliminary HB 200 targets

This modeling assumption does not mean PacifiCorp has determined Dave Johnston Unit 4 is the only site for a CCUS retrofit. As described in the 2023 IRP action plan, PacifiCorp is engaged in a request for expressions of interest process and will soon be issuing a request for proposals that will help identify candidates for potential CCUS retrofits and help refine cost-and-performance assumptions.

The installation of CCUS in 2028 replaces the coal unit. The CCUS does not extend the life of Dave Johnston 4 beyong 2039. There is a net reduction of capacity due to the parasitic load associated with the carbon capture equipment.[8]

Figure 9.66 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when CCUS is installed on Dave Johnston Unit 4 in 2028. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2042, the PVRR(d) shows that the portfolio with CCUS installed on Dave Johnston Unit 4 project is $857 million higher cost than the preferred portfolio.

When the CCUS retrofit is installed in 2028, the carbon capture technology increases the costs associated with Dave Johnston Unit 4. This shows up as increased fixed costs for coal and gas resources in the chart at left. This is partially offset by reduced emissions costs.

[8] Upon installation of the carbon capture equipment, Dave Johnston Unit 4's rating is 233 MW. As a coal-fired facility without carbon capture equipment, Dave Johnston Unit 4's rating is 330 MW.

Figure 9.66 – Increase/(Decrease) in System Costs when CCUS is Installed on Dave Johnston Unit 4 in 2028

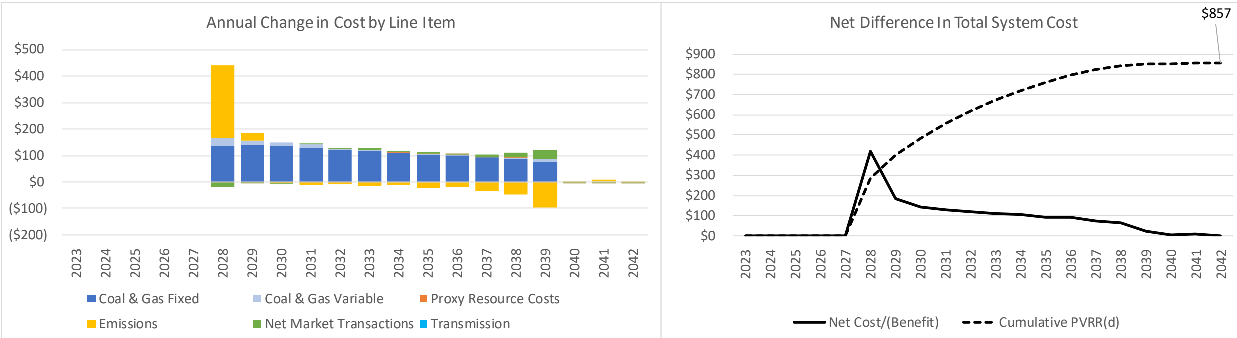


Figure 9.66 summarizes the PVRR(d) of the P21-DJ4 CCUS portfolio relative to the preferred portfolio under a range of different price-policy scenarios. The portfolio that includes the CCUS retrofit at Dave Johnston Unit 4 is higher cost than the preferred portfolio. This trend holds true for both the ST PVRR and the risk-adjusted PVRR results. Both portfolios, as measured by ENS, are very reliable. Emissions are slightly lower when CCUS is installed on Dave Johnston Unit 4. The magnitude of the increased cost in the portfolio that includes a CCUS retrofit on Dave Johnston Unit 4 in 2028, which would be situs-assigned to Wyoming customers, is expected to exceed the cost containment language set forth in HB 200, and for this reason, it is not included in the preferred portfolio. Nonetheless, PacifiCorp recognizes that this analysis is driven by a wide range of assumptions specific to the cost and commercial structure of CCUS opportunities. Consequently, PacifiCorp has established an action plan with a CCUS action item to continue with the on-going request for expressions of interest process and to proceed with a request for proposals process that will help identify potential sites, costs, and commercial structures that will allow us to update this analysis after the 2023 IRP.

CHAPTER 10 – ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2023 Integrated Resource Plan (IRP) action plan identifies steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio.
- PacifiCorp's 2023 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).
- The 2023 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and carbon dioxide (CO_2) emission polices.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2023 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver its preferred portfolio, with a focus on the front ten years of the planning horizon. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions and other trigger events during the action plan time frame that could materially impact resource acquisition strategies.

The 2023 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2023 IRP, such as capital and operating costs, are based upon recent cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the 2023 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2023 IRP acquisition path analysis, this chapter also includes discussion of the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;

- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2023 IRP Action Plan

The 2023 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2023 IRP public-input process. Table 10.1 details specific 2021 IRP action items by resource category.

Table 10.1 – 2023 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Colstrip Units 3 and 4:** • PacifiCorp pursues a beneficial change in ownership agreements that will enable an exit from the Colstrip project in Montana by 2030.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP preferred portfolio target exit date of December 31, 2025.
1c	**Naughton Units 1 and 2:** • PacifiCorp will initiate the process of converting Naughton Units 1 and 2 to natural gas beginning Q2 2023, including obtaining all required regulatory notices and filings. Natural gas operations are anticipated to commence spring of 2026. • PacifiCorp will initiate the closure of the Naughton South Ash Pond no later than the end of December 2025 when coal operations cease, and will complete closure by October 17, 2028, as required under its pond closure extension submission.
1d	**Jim Bridger Units 1 and 2 Gas Conversion:** • PacifiCorp has initiated the process of ending coal-fueled operations. The Wyoming Air Quality Division issued an air permit on December 28, 2022, for the natural gas conversion. All required regulatory notices and filings will be completed by end of 2023. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.

1e	**<u>Carbon Capture, Utilization, and Storage / Wyoming House Bill 200 Compliance:</u>** • PacifiCorp will complete evaluation of the information received as part of the CCUS RFP and RFI processes by the end of Q3 2023. • PacifiCorp will submit, for Wyoming Public Service Commission approval, a final plan in compliance with the low-carbon energy portfolio standard no later than March 31, 2024.
1f	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the EPA's determination of the states' second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.
1g	**<u>Natrium™ Demonstration Project:</u>** • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project. • By Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders. • By 2027, PacifiCorp will begin training operators. PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.
1h	**<u>Ozone Transport Rule Compliance:</u>** • PacifiCorp will assess the impact of EPA's finalized Ozone Transport Rule from March 2023, relative to the assumptions contained in the 2023 IRP. • PacifiCorp will continue to engage with the EPA, state agencies, and stakeholders to achieve Ozone Transport Rule compliance outcomes that provide environmental benefits, support reliable energy delivery and are cost effective. • Based on the Ozone Transport Rule trading program and the associated benefits for reducing NOx emissions, PacifiCorp will install selective non-catalytic reduction retrofit equipment at the following units by 2026: Huntington Units 1 and 2, Hunter Units 1-3, and Wyodak. The Company will initiate procurement and permitting activities beginning Q2 2023.

Action Item	2. New Resource Actions
2a	**Customer Preference Request for Proposals:** • PacifiCorp is continuously receiving and evaluating requests for voluntary customer programs in Utah and Oregon. PacifiCorp may use the marginal resources from ongoing 2022AS RFP and future request for proposals to fulfill customer need. In some cases, customer preference may necessitate issuance of a request for proposals to procure resources within the action plan window. • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2023, which may necessitate issuance of a request for proposals to procure resources within the action plan window.
2b	**2024 All-Source Request for Proposals:** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources aligned with the 2023 IRP preferred portfolio that can achieve commercial operations by the end of December 2028. • In Q4 2023, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In Q1 2024, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In Q3 2024, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q4 2024, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. PacifiCorp will file a certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q1 2025 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the all-source RFP are expected to achieve commercial operation by December 31, 2028, or earlier.

2c	**<u>2022 All-Source Request for Proposals:</u>** • In April 2022 PacifiCorp issued an all-source Request for Proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2027. • In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon. Similarly, PacifiCorp will make a filing in Utah for any applicable significant energy resources on final shortlist. PacifiCorp will file certificate of public convenience and necessity (CPCN) applications, as applicable, and • By Q4 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • Winning bids from the 2022 all-source RFP are expected to achieve commercial operation by December 31, 2027, or earlier.

<table>
<tr><th>Action Item</th><th>3. Transmission Action Items</th></tr>
<tr><td>3a</td><td><u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>
In Q4 2024, construction of Energy Gateway South is expected to be completed and placed in service.</td></tr>
<tr><td>3b</td><td><u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u>
In Q4 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service.</td></tr>
<tr><td>3c</td><td><u>Boardman-to-Hemingway (500 kV transmission line):</u>
Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement.
Continue to participate in the development and negotiations of the construction agreement.
Continue to participate in “pre-construction” activities in support of the 2026 in-service date.
Continue negotiations for plan of service post B2H for parties to the permitting agreement.</td></tr>
<tr><td>3d</td><td>Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids</td></tr>
<tr><td>3e</td><td>Continue permitting support for Gateway West segments D.3 and E. Initiate preliminary permitting and development activities for future transmission investments not currently included in the preferred portfolio. These future transmission projects can include development of additional Energy Gateway segments and exploration of new routes that have connections to other regions (i.e., connecting southern Oregon to the east with connections to the desert southwest). These activities will enable PacifiCorp to prepare for potential growth in new large loads seeking new service over the next decade.</td></tr>
</table>

Action Item	4. Demand-Side Management (DSM) Actions
4a	**<u>Energy Efficiency Targets:</u>** • PacifiCorp will acquire cost-effective energy efficiency resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2023 IRP. • PacifiCorp will pursue cost-effective energy efficiency resources as summarized in the table below:

Year	Annual 1st Year Energy (GWh)	Annual Incremental Capacity (MW)
2023	543	123
2024	551	220
2025	596	259
2026	563	197

• PacifiCorp will pursue cost-effective demand response resources targeting annual system capacity[1] selections from the preferred portfolio[2] as summarized in the table below:

Year	Annual Incremental Capacity (MW)
2023	72
2024	39
2025	152
2026	109

[1] Capacity impacts for demand response include both summer and winter impacts within a year.
[2] A portion of cost-effective demand response resources identified in the 2021 2023 preferred portfolio in 2023 for Oregon and Washington represent planned volumes expected are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources offered through approved programs. subsequently procured under the previously issued RFP in compliance with state level procurement requirements.

Action Item	5. Market Purchases
5a	**<u>Market Purchases:</u>** • Acquire short-term firm market purchases for on-peak delivery from 2023-2025 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
Action Item	**6. Renewable Energy Credit (REC) Actions**
6a	**<u>Renewable Portfolio Standards (RPS):</u>** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • PacifiCorp will issue RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through 2024 and future compliance periods, as needed.
6b	**<u>Renewable Energy Credit Sales:</u>** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Progress on 2021 Action Plan

This section describes progress that has been made on previous action plan items documented in the 2021 IRP filed with state commissions on September 1, 2021. Many of these action items have been superseded in some form by items identified in the 2023 IRP action plan. The status for all action items from the 2023 IRP is summarized in Table 10.2.

Table 10.2 – 2021 IRP Action Plan Status Update

Action Item	1. Existing Resource Actions	Status
1a	**Colstrip Units 3 and 4:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.	PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2023 IRP preferred portfolio target exit date of December 31, 2025 for Colstrip Unit 3, and December 31, 2029 for Colstrip Unit 4.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.	PacifiCorp is proceeding with this action item on schedule.
1b	**Naughton Units 1 and 2:** • PacifiCorp will initiate the process of retiring Naughton Units 1-2 by the end of December 2025, including completion of all required regulatory notices and filings. • By the end of Q2 2023, PacifiCorp will confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, PacifiCorp will initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2.	PacifiCorp will initiate the processes for permitting and converting Naughton Units 1 and 2 to natural gas. Additional information on this action item is included in the 2023 action plan.

	• By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	
1c	**<u>Jim Bridger Units 1 and 2 Gas Conversion:</u>** • PacifiCorp will initiate the process of ending coal-fueled operations and seeking permitting for a natural-gas conversion by 2024, including completion of all required regulatory notices and filings. • By the end of Q2 2022, PacifiCorp will finalize an employee transition plan. • By the end of Q2 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements. •	PacifiCorp is proceeding with this action item on schedule. Additional information on this action item is included in the 2023 action plan.
1d	**<u>Carbon Capture, Utilization, and Sequestration/Wyoming House Bill 200 Compliance:</u>** • PacifiCorp issued a carbon capture, utilization, and sequestration (CCUS) request for expression of interest (REOI) on June 29, 2021. PacifiCorp will complete the 2021 CCUS REOI process and utilize any new relevant information. Additional model sensitivities will be run accordingly. • PacifiCorp will issue a CCUS Request for Proposals (RFP) in 2022. The 2021 CCUS REOI responses will inform the scope of the CCUS RFP. • A completed CCUS Front End Engineering & Design Study (FEED Study) based on a new CCUS technology was submitted to PacifiCorp in July 2021 for Dave	• The CCUS REOI was completed in 2021. The REOI responses informed the Company's feasibility analysis, completed in 2022 as part of Wyoming HB 200 compliance. • PacifiCorp issued two CCUS Request for Proposals (RFP), one for Dave Johnston Unit 4 and one for Jim Bridger Units 3 and/or 4, on November 1, 2022. Proposals were due March 7, 2023, and the company is evaluating information received. Where appropriate, information received from the RFP process will be used to update and inform model sensitivities that can

	Johnston Unit 2. Third-party review of the FEED Study will be completed by Q1 2022, and model sensitivities will subsequently be run as needed, with FEED Study assumptions and inputs as appropriate. • Subject to finalization of rules by the Wyoming Public Service Commission (WPSC) to implement House Bill 200 (HB 200), the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), by March 31, 2022, PacifiCorp will file with the WPSC an initial CCUS application to establish intermediate CCUS standards and requirements. • Subject to finalization of rules by the WPSC to implement HB 200, the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), PacifiCorp will submit for WPSC approval a final plan with its proposed energy portfolio standard for dispatchable and reliable low-carbon electricity, its plan for achieving the standard, and a target date of no later than July 1, 2030.	be compared to outcomes in the 2023 IRP preferred portfolio. • Third parties reviewed the FEED Study in Q1 2022 and Q1 2023. Model sensitivities were completed in the 2023 IRP, with FEED Study assumptions and inputs as appropriate, and CCUS was not found to be economical. • PacifiCorp filed with the Wyoming Public Service Commission (WPSC) on March 31, 2022, an initial CCUS application to establish intermediate CCUS standards to implement House Bill 200 (HB 200). Additional information on this action item is included in the 2023 action plan.
1e	**Regional Haze Compliance:** • Following the resolution of first planning period regional haze compliance disputes, and the submission of second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the Environmental Protection Agency, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.	• States' submitted their state implementation plans for second planning period in 2022. Additional information on this action item is included in the 2023 action plan.

Action Item	2. New Resource Actions	Status
2a	**<u>Customer Preference Request for Proposals:</u>** • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2022, which may necessitate issuance of a request for proposals to procure resources within the action plan window..	PacifiCorp is in active discussions with the participating communities and anticipates filing an application for approval of the program with the Utah Public Service Commission in 2023.
2b	**<u>Acquisition and Repowering of Foote Creek II-IV and Rock River I:</u>** • In Q3 2021, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Foote Creek II-IV in order to issue repowering contracts in Q1 2022 in support of a late 2023 in-service date • In Q1 2022, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Rock River I following the expiration of the existing power purchase agreement in order to issue repowering contracts in Q3 2022 to support a late 2024 in-service date.	• In Q2 2022, the Wyoming Public Service Commission approved a CPCN for the project, and PacifiCorp acquired the Foote Creek II-IV facilities and began repowering construction activities. PacifiCorp will continue construction activities in 2023 to achieve a late 2023 in-service date. • In Q3 2022, the Wyoming Public Service Commission approved a CPCN for the project, and PacifiCorp acquired the project in Q1 2023. PacifiCorp will initiate construction activities in Q2 2023 to support a late 2024 in-service date.
2c	**<u>Demonstration Project:</u>** • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable.	• No required regulatory filings have been identified to date; PacifiCorp will continue to monitor

	• By the end of 2023, PacifiCorp expects to finalize commercial agreements for the Natrium™ project. • Q2 2024, PacifiCorp expects to develop a community action plan in coordination with community leaders. • By 2027, PacifiCorp will begin training operators. • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.	• Negotiations on the final commercial agreement are ongoing • [Complete] • N/A • No required regulatory filings have been identified to date; PacifiCorp will continue to monitor
	2022 All-Source Request for Proposals: • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2026. • In September 2021, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In October 2021, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In January 2022, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q2 2022, PacifiCorp will identify an initial shortlist in advance of annual Cluster Request Window.	PacifiCorp filed a 2022 all source request for proposals (2022AS RFP) and received approval in three states by Q2 2022 in order to issue the solicitation to the market on April 29, 2022. PacifiCorp bid twelve eligible self-build (benchmark) resources on December 9, 2022, and on March 14, 2023, PacifiCorp received 302 bids from 74 developers and 93 different projects sites across six states. A final shortlist is expected by late Q2 2023 or early Q3 2023 with resources contracted by the end of Q4 2023.

	• In Q1 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q2 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. By Q4 2025-2026, winning bids from the all-source RFP are expected to achieve commercial operation. Resources must have commercial operation date of December 31, 2026, or earlier.	
2b	**2020 All-Source Request for Proposals:** • PacifiCorp filed for approval of the final shortlist in Oregon in June 2021. • In September 2021, PacifiCorp will file CPCN applications in Wyoming, as applicable, for final shortlist. • In Q4 2021, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist. •	The 2020AS RFP has concluded with the procurement of 1,792 MW of wind, 495 MW of solar additions, and 697 200 MW of battery storage capacity, which was paired with the solar.

<table>
<tr><th>Action Item</th><th>3. Transmission Action Items</th><th>Status</th></tr>
<tr><td>3a</td><td><u>Energy Gateway South:</u>
By December 31, 2023, PacifiCorp will seek to build the approximately 400-mile, 500-kilovolt (kV) transmission line from the Aeolus substation near Medicine Bow, Wyoming to the Clover substation near Mona, Utah.
By Q2 2021, receive the final CPCN from the Wyoming Public Service Commission and the Public Service Commission of Utah (initial filing dates for the CPCN to be determined after stakeholder engagement).
By the end of Q4 2021, issue full notice to proceed to construct Energy Gateway South.
In Q4 2023, construction of Energy Gateway South is completed and placed in service.</td><td>Energy Gateway South has been moved to a target in-service date of Q4 2024.

This action item has been superseded by the Energy Gateway South Action in the 2023 action plan.</td></tr>
<tr><td>3b</td><td><u>Utah Valley Reinforcements:</u>
Utah Valley Reinforcements: As necessary to facilitate interconnection of customer-preference resources, PacifiCorp will proceed with system reinforcements in the Utah Valley.
In Q2 2020, complete the Spanish Fork 345 kV/138 kV transformer upgrade.
In Q4 2020, complete rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley.</td><td>In-service dates have been revised based on current project schedules as follows:
In Q1 2021, PacifiCorp completed the Spanish Fork 345 kV/138 kV transformer upgrade. The completion date for the transformer upgrade was shifted to 2021 due to outage constraints on the line. The remaining scope to complete improvements at a third-party owned substation was completed in Q2 2021.
In Q2 2021, PacifiCorp completed the rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley. The completion of this project shifted to 2021 due to delays in steel pole deliveries.</td></tr>
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3c	**<u>Northern Utah Reinforcements:</u>** • Rebuild two miles of the Morton Court –Fifth West 138 kV line. • Loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond. • Complete identified plan of service supporting 2019 IRP preferred portfolio for resource additions in northern Utah.	The rebuild of two miles of the Morton Court –Third West 138 kV line is scheduled for Q2 2026. The project to loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond is now scheduled for Q4 2023.
3d	**<u>Utah South Reinforcements:</u>** • Develop plan of service in support of 2019 IRP preferred portfolio for resource additions in southern Utah. • Complete rebuild of the Mona –Clover #1 & #2 345 kV lines. • Identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah. •	In-service dates have been revised based on current project schedules. Washington action items are addressed in PacifiCorp's response to item 3e below. In Q3 2024 PacifiCorp is scheduled complete rebuild of the Mona –Clover #1 & #2 345 kV lines. In Q2 2026 PacifiCorp is scheduled to identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah.
3e	**<u>Yakima Washington Reinforcements:</u>** • To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in	The Vantage-Pomona Heights 230kV line was completed in August 2020.

	network upgrade requirements for generator interconnection requests. • In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process). • By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.	
3f	**Boardman to Hemingway:** • Continue to support the project under the conditions of the Boardman to Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue analysis in efforts to identify customer benefits that may include contributions to reliability, interconnection of additional resources, geographical diversity of intermittent resources, Energy Imbalance Market, and resource adequacy. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.	PacifiCorp filed for certificates of public convenience and necessity with the Idaho Public Utilities Commission and Wyoming Public Service Commission in Q1 2023. Also, in Q1 2023, Idaho Power and PacifiCorp signed a Joint Purchase and Sale agreement and PacifiCorp and Bonneville Power signed various service agreements as conditions of the Term Sheet between the parties.
3g	Energy Gateway West: • Energy Gateway West Segment D.2, continue construction with target in-service date of 12/31/2020. • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: For Segments D.3, and E, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. Also, continue to	Energy Gateway West Segment D.2 was completed in Q4 2020. The other action items remain on schedule. This action item has been superseded by the Energy Gateway West Action in the 2023 action plan.

<table>
<tr><td></td><td>support the projects by providing information and participating in public outreach.</td><td></td></tr>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th><th>Status</th></tr>
<tr><td>4a</td><td>
<u>Energy Efficiency and Demand Response Targets:</u>

PacifiCorp will acquire cost-effective energy efficiency (Class 2 DSM) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions will be provided in Appendix D in Volume II of the 2021 IRP.
<table>
<tr><th>Year</th><th>Annual 1st Year Energy (GWh)</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2021</td><td>510</td><td>157</td></tr>
<tr><td>2022</td><td>492</td><td>138</td></tr>
<tr><td>2023</td><td>486</td><td>144</td></tr>
<tr><td>2024</td><td>529</td><td>164</td></tr>
</table>
* Note, Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.
PacifiCorp will pursue cost-effective Class 1 (demand response) resources targeting annual system capacity selections from the preferred portfolio as summarized in Appendix D in Volume II of the 2021 IRP.
<table>
<tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2021</td><td>0</td></tr>
<tr><td>2022</td><td>123</td></tr>
<tr><td>2023</td><td>242</td></tr>
<tr><td>2024</td><td>184</td></tr>
</table>

</td><td>
Energy Efficiency Targets

2021 reporting indicates the company acquired 466GWh of energy efficiency system wide. This equates to 143 MW of capacity reductions.

Preliminary 2022 reporting indicates the company acquired 393 GWh of energy efficiency system wide. This equates to 110 MW of capacity reductions.

Coupling preliminary 2021 reporting with 2022 actuals, acquired 859 GWh of energy efficiency over the two years. This equates to capacity reductions of 253 MW (using the same GWh/MW relationship)

At the end of January 2021, PacifiCorp issued a demand response RFP to identify the potential acquisition of cost-effective flexible capacity. PacifiCorp procured and co-filed for new demand response resources following the completion of 2021 IRP. While not all MW volumes were not dispatched in 2022, the Company was able to have programs approved representing 171 MW of new DR resources since the 2021 IRP was published.
</td></tr>
</table>

<table>
<tr><th>Action Item</th><th>5. Front Office Transactions</th><th>Status</th></tr>
<tr><td>5a</td><td><u>Market Purchases:</u>

Acquire short-term firm market purchases for on-peak delivery from 2019-2021 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price.
Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price.
Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
</td><td>Market purchases, inclusive of day-ahead, balance of month, prompt, and forward hedging transactions, but not accounting for any offsetting hedging sales, were made for on peak delivery in the following periods and at the following quantities:
<table>
<tr><th>Year</th><th>Minimum MW</th><th>Maximum MW</th></tr>
<tr><td>2020</td><td>375</td><td>1,180</td></tr>
<tr><td>2021</td><td>550</td><td>2,179</td></tr>
<tr><td>2022</td><td>575</td><td>1,865</td></tr>
<tr><td>2023</td><td>125</td><td>1,870</td></tr>
</table>
Market purchases are made in accordance with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices and include a mix of the transaction types identified in item 5a.</td></tr>
<tr><th>Action Item</th><th>6. Renewable Energy Credit Actions</th><th>Status</th></tr>
<tr><td>6a</td><td><u>Renewable Portfolio Standards (RPS):</u>

PacifiCorp will pursue unbundled RFPs to meet its state RPS compliance requirements.
As needed, issue RFPs seeking then current-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2020. As needed, issue RFPs seeking
</td><td>PacifiCorp continues to evaluate the need for unbundled RECs and will issue RFPs to meet its state RPS compliance requirements as needed in California. Most recently, PacifiCorp issued an RFP for RECs to meet California RPS compliance requirements.</td></tr>
</table>

	then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington RPS targets.	
6b	**<u>Renewable Energy Credit Sales:</u>** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp issued reverse RFPs in April 2019, March 2020, February 2021, October 2021, and September 2022. PacifiCorp will continue to engage in bilateral REC sales and issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the 2023 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis including load, private generation, changes in available resources, and emissions polices. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2023 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources qualifying for federal income tax credits, market purchases, and energy efficiency and demand response resources are consistently selected. Further, the procurement processes associated with these resource actions are well underway. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2023 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, CO_2 policy also influences resource selections in the 2023 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event, PacifiCorp identifies the planning scenario assumption affecting both short-term (2023-2032) and long-term (2032-2040) resource strategies.

Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[1] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability and flexibility at a reasonable cost. summarizes PacifiCorp's 2023 IRP acquisition path analysis, which provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

[1] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

Table 10.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
Higher sustained load growth	High economic drivers accounting for 95% prediction interval and low private generation assumption.	• In 2028, there is an increase of 2 percent higher sustained load growth than the base case forecast, resulting in an increase in peak capacity requirements of 271 MW increasing further to nearly 337 MW in 2032. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades • The higher peak capacity requirements relative to the base case forecast results in additional resource need, increased market reliance and/or shifts in timing of planned resources or coal unit retirements. • As the higher load is distributed over multiple load areas and across years, additional battery, solar and wind resources in combination will meet the higher demand.	• In 2042, there is an increase of 4 percent higher sustained load growth than the base case forecast, resulting in an increase in peak capacity requirements of 616 MW. • The higher peak capacity requirements relative to the base case forecast results in additional resource need, increased market reliance and/or shifts in timing of planned resources or coal unit retirements. • As the higher load is distributed over multiple load areas and across years, additional battery, solar and wind resources in combination will meet the higher demand.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
Lower sustained load growth	Low economic drivers accounting for 95% prediction interval and high private generation assumption.	• In 2028, there is 2 percent lower sustained load growth than the base case forecast, resulting in a decrease in peak capacity requirements of 256 MW decreasing further 288 MW in 2032. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • The lower peak capacity requirements relative to the base case forecast results in a reduction in resource need, decreased market reliance and/or shifts in timing of planned resources or coal unit retirements.	• In 2042, there is a 2 percent lower sustained load growth than the base case forecast, resulting in a decrease in peak capacity requirements of 363 MW. • The lower peak capacity requirements relative to the base case forecast results in a reduction in resource need, decreased market reliance and/or shifts in timing of planned resources or coal unit retirements.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
Higher sustained private generation penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• In 2028, peak capacity requirements are lower by 29 MW due to higher sustained private generation levels relative to the base case forecast. • In 2032, peak capacity requirements are lower by 63 MW due to higher sustained private generation levels relative to the base case forecast. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy.	• In 2042, peak capacity requirements are lower by 102 MW due to higher sustained private generation levels relative to the base case forecast. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy. • Timing differences in resource capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
Lower sustained private generation penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• In 2028, peak capacity requirements are higher by 44 MW due to lower sustained private generation levels relative to the base case forecast. • In 2032, peak capacity requirements are higher by 97 MW due to lower sustained private generation levels relative to the base case forecast. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy.	• In 2042, peak capacity requirements are higher by 293 MW due to lower sustained private generation levels relative to the base case forecast. • Timing differences in resource capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
High CO_2 prices with accelerated coal retirements	Fossil-fired generation is faced with a high CO_2 price beginning in 2025 at $4434/ton and reaching $132.70/ton by 2042 that drives all coal to be retired by 2030 (?)	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Accelerate timing of new resource additions including an advanced nuclear resource from 2033 to 2032. • By 2030 the portfolio swaps 600 MW of four hour battery for 600 MW of long duration storage and adds 790 MW of additional Solar resources. • Wind selections are slightly reduced until 2032, at which time the model adds a total of 3,714 MW incremental wind compared to the preferred portfolio. • Increase procurement of market purchases. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases 81 MW by 2032.	• By 2042, new nuclear peaking capacity is increased by 500 MW. • By 2042, DSM (energy efficiency and demand response combined) is increased by 366 MW and standalone storage capacity is increased by over 1,000 MW.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
No Natrium™ Advanced Nuclear Demonstration Project in 2030, and no other nuclear projects	See Volume 1, Chapter 9 (Modeling and Portfolio Selection Results), P05-No NUC portfolio	• Without the Natrium™ demonstration project, 289 MW of non-emitting peaking resource is added in 2030. • In 2032 the second advanced nuclear plant is replaced by 303 MW of non-emitting peaking resource and 200 MW of four-hour battery storage. • Higher costs and emissions result from increased fossil-fueled generation, emissions and net market transactions.	• In 2033, 303 MW of non-emitting peaking resources and 200 MW of four-hour battery storage replace 500 MW of nuclear capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
No Boardman-to-Hemingway (B2H) transmission segment in 2026	See Volume 1, Chapter 9 (Modeling and Portfolio Selection Results), P02b-No B2H portfolio	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Without B2H, 724 MW of standalone storage is built in 2027 as a requirement of not building the B2H line. • 300 MW of solar is removed from the portfolio in 2028, and 400 MW of wind shifts from Borah Populous in 2028 to Southern Oregon in 2029. • An additional 600 MW of storage is moved from Borah Populous to Southern Oregon in 2028. • 400 MW of wind is accelerated from 2033 into 2030. A reduction in resources results in increased reliance on the market and higher emissions from an increase in coal and gas generation. • Reduced flexibility and load-serving capability of the transmission system.	• An additional 600 MW of solar and 600 MW of storage is built in Southern Oregon in 2033.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2023-2032)	Long Term Resource Acquisition Strategy (2033-2042)
New Load	Incremental 3,000 MW of flat load entering the system in 2033	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades.	• Resources required to serve load – 2,000 MW wind, 1,600 MW solar, 1,600 MNW battery, and 881 MW non-emitting peaker. • Requires Boardman to Hemingway 2, Gateway South 2, D3.2 transmission line, Gateway Segment E and Gateway Segment E 2.

Procurement Delays

The main procurement risk is an inability to procure resources in the required timeframe to meet the least-cost, least-risk mix of resources identified in the preferred portfolio. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in a given action plan period. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.
- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all of the capacity needs.
- Temporarily drop below its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

The 2023 IRP includes a sensitivity that complies with the Utah requirement to perform a business plan sensitivity case consistent with the commission's order in Docket No. 15-035-04. This order sets forth the following parameters for this sensitivity case:

- Over the first three years, resources align with those assumed in PacifiCorp's December 2022 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

PacifiCorp will file a supplemental filing to its 2023 IRP filing that includes discussion and results of the sensitivities outlined in Volume I, Chapter 9 (Modeling and Portfolio Selection Results), including a discussion of this business plan sensitivity case summarizing portfolio differences between the business plan sensitivity case and the 2023 IRP preferred portfolio. This study will capture changes to the resource mix, present value revenue requirement of system costs, and implications on the near-term action plan. The supplemental filing will also be posted to PacifiCorp's IRP webpage at the following location: www.pacificorp.com/energy/integrated-resource-plan.

Resource Procurement Strategy

To acquire resources outlined in the 2023 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide economic benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs such as load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2023 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use a competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-Side Management[2]

PacifiCorp offers a robust portfolio of demand response and energy efficiency programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp provides Class 4 DSM offerings, and has continued ***watt***smart outreach and communications. Educating customers regarding energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will continue to evaluate how to best incorporate potential DSM programs into the broader all-source RFP process discussed above or whether separate RFPs focused on these resources are warranted based on state-specific requirements and program needs.

Small Scale Renewable Energy Supply

In order to fulfil Oregon regulatory requirements for small-scale renewable resources, PacifiCorp plans to issue a small-scale renewable energy RFP in 2024 to solicit resources within its territory which are 20 MW or smaller and can be commercially operational by 2028. Currently, Oregon's new HB 2021 legislation and associated Clean Energy Plan is driving a specific evaluation of small-scale renewables that may help to identify the costs and benefits of smaller (20 MW or less installed capacity) community-owned renewables projects across PacifiCorp's service territory. This study is addressed in PacifiCorp's 2023 Oregon Clean Energy Plan.

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time.

[2] Class 1 DSM is most commonly referred to as "demand response" in the 2023 IRP; Class 2 DSM is most commonly referred to as "energy efficiency". Class 4 DSM describes energy efficiency measures achieved through public outreach and education.

Alternately and depending on contractual terms, purchasing power from a third party in a long-term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power-purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Power-purchase agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation may affect PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives.

As evident in the 2023 IRP, known and prospective environmental regulations, such as the Ozone Transport Rule (OTR) and Inflation Reduction Act (IRA), can impact utilization of resources and investment decisions. Both of these federal government directed changes require further definition. For the OTR, a final decision regarding the timing of Wyoming's participation remains in flux. For the IRA, which exceeds 700 pages, there has been insufficient time for this comprehensive legislation to be digested fully in resource planning. PacifiCorp's 20230 IRP captures those components which are best understood and most appropriate to the IRP's scope, including impacts on production tax credits and investment tax credits for non-emitting resources. Of key interest will be the U.S. Treasury Department's implementation of the IRA's clean energy tax credit provisions, which will address the allocation of bonus credits, the eligibility of certain credits to certain technologies, and other key issues.

Compliance strategies will be affected by how and whether states or the federal government choose to implement further policies related to greenhouse gases and nitrogen oxide. State or federal frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a CO_2 tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as CO_2 capture with sequestration. As mentioned above, plant CO_2 emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; (2) reduce volatility of net power costs for PacifiCorp's customers. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market changes. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the president of Pacific Power, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within power volume hedge limits and natural gas percent hedge volume limits.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long-run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take

contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total generation capacity relative to customer load requirements at a given point in time.

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise.

Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

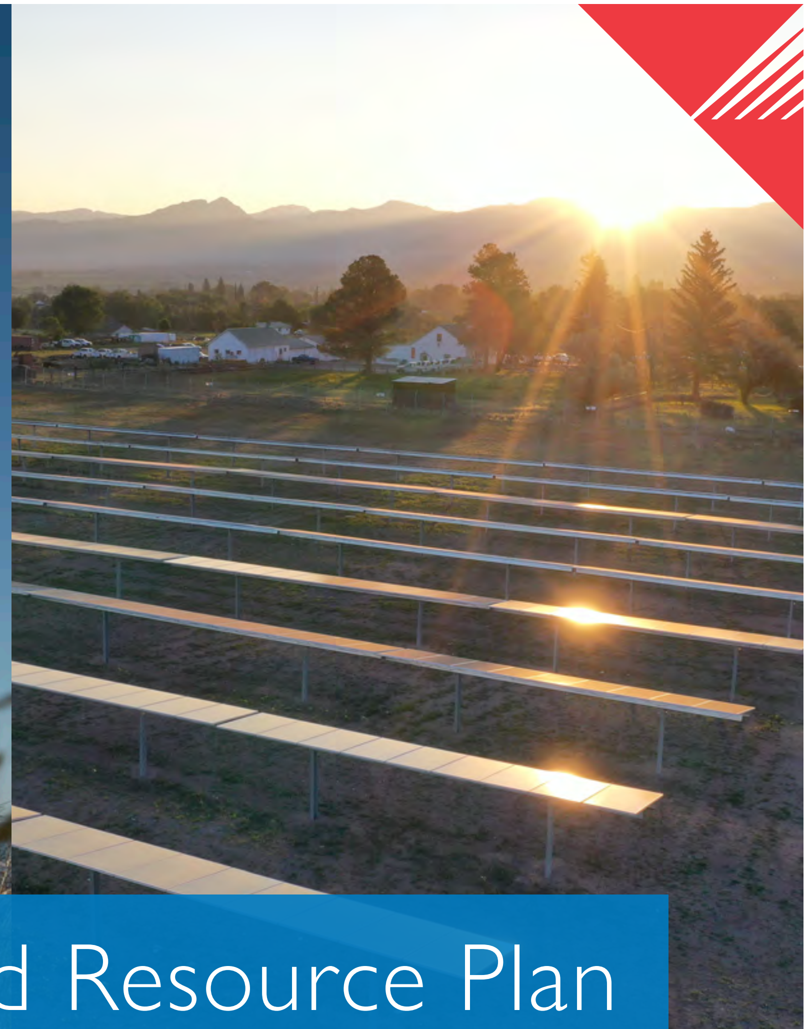
Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

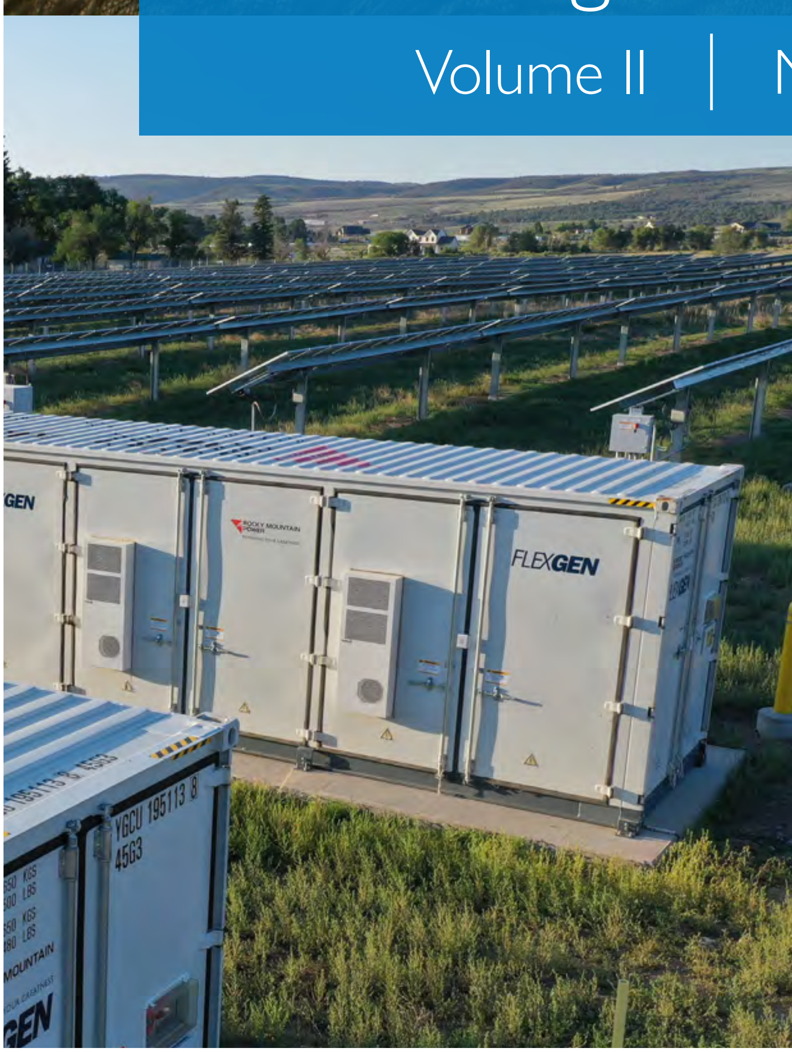
Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continues to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2023 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.



2023 Integrated Resource Plan

Volume II | March 31, 2023



PACIFICORP

APPENDIX A – LOAD FORECAST

Introduction

This appendix reviews the load forecast used in the modeling and analysis of the 2023 Integrated Resource Plan ("IRP"), including scenario development for case sensitivities. The load forecast used in the IRP is an estimate of the energy sales and peak demand over a 20-year period. The 20-year horizon is important to anticipate electricity demand to develop a timely response of resources.

In the development of its load forecast PacifiCorp employs econometric models that use historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and behavior changes. The forecast is divided into classes that use energy for similar purposes and at comparable retail rates. These separate customer classes include residential, commercial, industrial, irrigation, and lighting customer classes. The classes are modeled separately using variables specific to their usage patterns. For residential customers, typical energy uses include space heating, air conditioning, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions, and various other end use appliances. Commercial and industrial customers use energy for production and manufacturing processes, space heating, air conditioning, lighting, computers, and other office equipment.

Jurisdictional peak load forecasts are developed using econometric equations that relate observed monthly peak loads, peak producing weather and the weather-sensitive loads for all classes. The system coincident peak forecast, which is used in portfolio development, is the maximum load required on the system in any hourly period and is extracted from the hourly forecast model.

Summary Load Forecast

The Company updated its load forecast in May 2022. The compound annual load growth rate for the 10-year period (2023 through 2032) is 2.69 percent. Relative to the load forecast prepared for the 2021 IRP, PacifiCorp's 2032 forecast load requirement increased in Oregon, Utah and Idaho, while PacifiCorp system load requirement increased 17.00 percent in 2032. Figure A.1 has a comparison of the load forecasts from the 2023 IRP to the 2021 IRP.

Figure A.1 – PacifiCorp System Energy Load Forecast Change, at Generation, pre-DSM

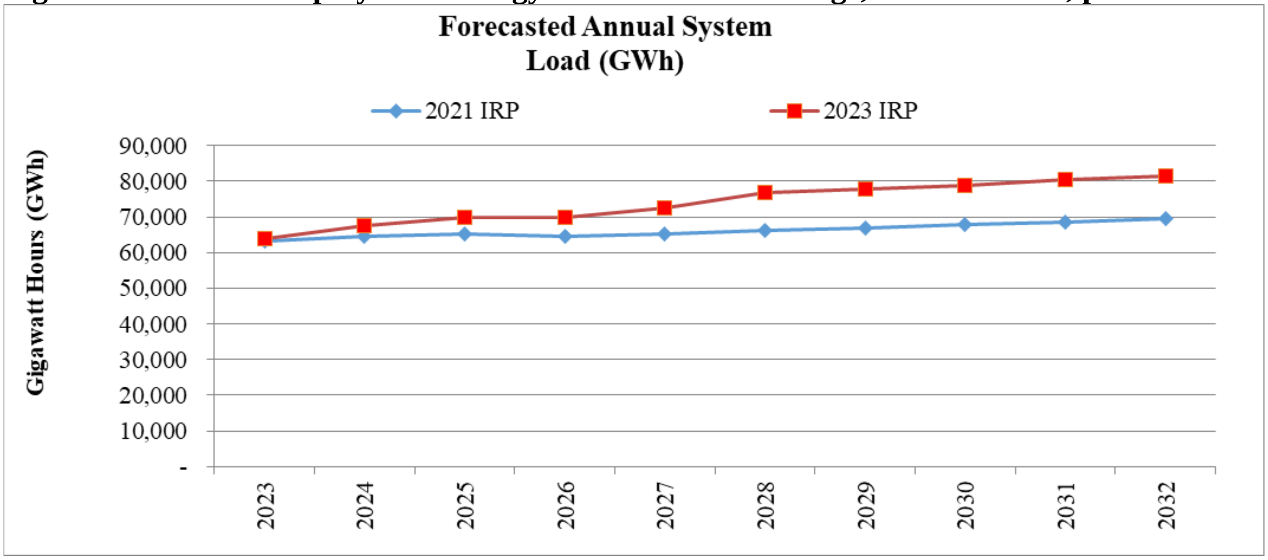


Table A.1 and Table A.2 show the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures.[1] Tables A.3 and A.4 show the forecast changes relative to the 2021 IRP load forecast for loads and coincident system peak, respectively.

Table A.1 – Forecasted Annual Load, 2023 through 2032 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2023	64,032,930	16,209,670	4,638,720	863,330	28,599,180	9,644,200	4,077,830
2024	67,499,270	18,374,450	4,692,110	861,560	29,740,030	9,763,560	4,067,560
2025	69,805,060	19,730,320	4,700,760	855,220	30,361,220	10,074,860	4,082,680
2026	69,938,420	20,457,650	4,721,760	852,970	29,687,480	10,113,240	4,105,320
2027	72,649,770	21,761,290	4,756,830	853,180	31,034,420	10,116,940	4,127,110
2028	76,681,120	23,445,960	4,811,200	856,480	33,183,740	10,229,110	4,154,630
2029	77,919,280	23,952,780	4,841,310	855,160	33,861,360	10,239,970	4,168,700
2030	78,811,840	24,066,060	4,885,350	855,790	34,483,900	10,332,550	4,188,190
2031	80,380,690	24,821,690	4,930,700	856,600	35,199,890	10,364,120	4,207,690
2032	81,321,780	25,160,880	4,990,400	859,960	35,600,350	10,476,730	4,233,460
Compound Annual Growth Rate							
2023-32	**2.69%**	**5.01%**	**0.82%**	**-0.04%**	**2.46%**	**0.92%**	**0.42%**

[1] Energy efficiency load reductions are included as resources in the Plexos model.

Table A.2 – Forecasted Annual Coincident Peak Load (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2023	11,033	2,650	835	147	5,408	1,221	772
2024	11,427	2,833	846	147	5,537	1,295	770
2025	11,747	3,011	857	148	5,628	1,301	803
2026	11,758	3,054	871	148	5,572	1,305	808
2027	12,051	3,188	887	150	5,707	1,306	813
2028	12,485	3,323	905	151	5,993	1,317	794
2029	12,683	3,487	926	156	6,023	1,292	798
2030	12,815	3,507	946	158	6,101	1,301	803
2031	13,123	3,631	966	160	6,214	1,311	841
2032	13,209	3,632	985	161	6,268	1,316	847
Compound Annual Growth Rate							
2023-32	**2.02%**	**3.56%**	**1.86%**	**1.03%**	**1.65%**	**0.83%**	**1.03%**

Table A.3 – Annual Load Change: May 2022 Forecast less June 2022 Forecast (Megawatt-hours) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2023	789,940	450,990	(17,310)	(19,170)	388,800	(112,270)	98,900
2024	3,047,960	2,268,330	(18,530)	(26,610)	947,850	(199,700)	76,620
2025	4,642,800	3,490,810	(29,480)	(33,670)	1,020,190	117,860	77,090
2026	5,411,390	4,038,830	(39,130)	(38,160)	1,334,560	33,730	81,560
2027	7,471,370	5,152,040	(39,360)	(39,230)	2,333,490	(23,110)	87,540
2028	10,597,700	6,589,320	(39,200)	(39,800)	3,990,880	1,290	95,210
2029	11,150,620	6,915,680	(38,590)	(40,210)	4,251,510	(38,250)	100,480
2030	11,088,630	6,798,020	(37,750)	(42,820)	4,328,150	(61,120)	104,150
2031	11,852,040	7,341,690	(27,480)	(42,960)	4,566,100	(101,550)	116,240
2032	11,814,570	7,448,410	(22,820)	(43,290)	4,388,360	(85,440)	129,350

Table A.4 – Annual Coincident Peak Change: May 2022 Forecast less June 2022 Forecast (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2023	342	188	46	5	154	(58)	7
2024	620	353	50	6	211	(5)	5
2025	805	511	53	6	209	(2)	28
2026	891	540	61	7	264	(10)	29
2027	1,112	661	71	7	356	(15)	31
2028	1,441	784	82	8	568	(12)	12
2029	1,550	936	96	14	533	(43)	14
2030	1,577	945	108	16	538	(47)	17
2031	1,785	1,060	120	18	584	(45)	49

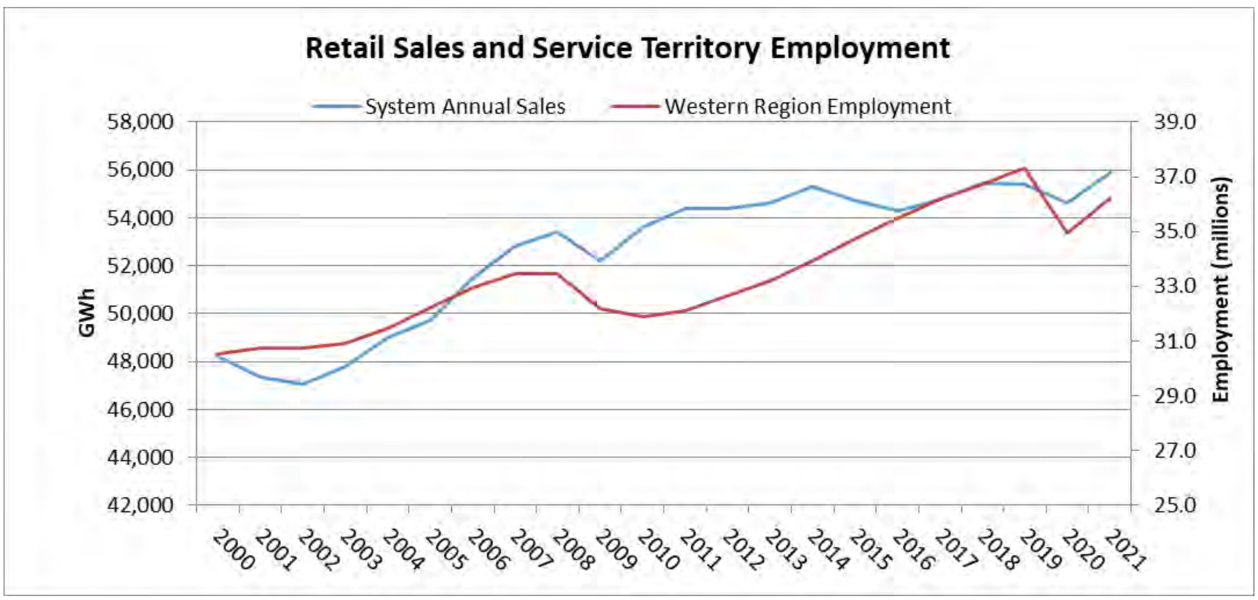
2032	1,807	1,077	133	19	572	(49)	56

Load Forecast Assumptions

Regional Economy by Jurisdiction

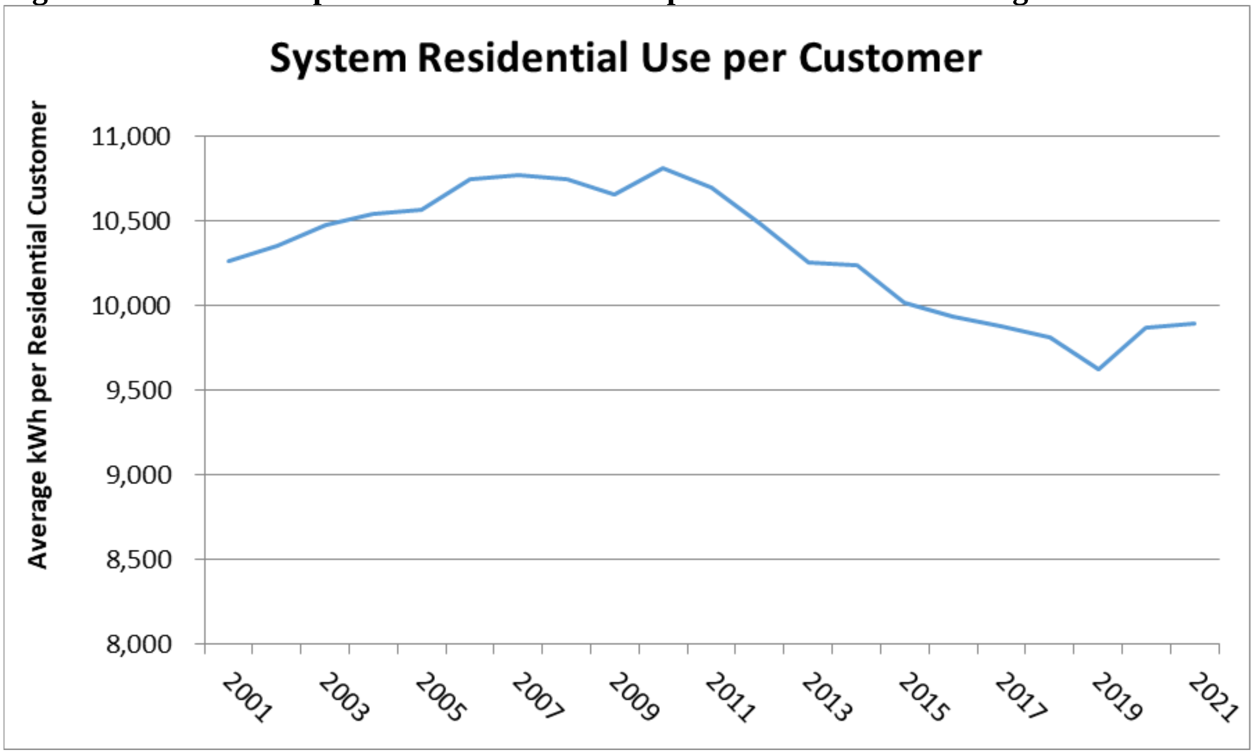
The PacifiCorp electric service territory is comprised of six states and within these states the Company serves customers in a total of 90 counties. The level of retail sales for each state and county is correlated with economic conditions and population statistics in each state. PacifiCorp uses both economic data, such as employment, and population data, to forecast its retail sales. Looking at historical sales and employment data for PacifiCorp's service territory, 2000 through 2021, in Figure A.2, it is apparent that the Company's retail sales are correlated to economic conditions in its service territory, and most recently the economic downturn and rebound from the COVID-19 pandemic.

Figure A.2 – PacifiCorp Annual Retail Sales 2000 through 2021 and Western Region Employment



The 2023 IRP forecast utilizes the March 2022 release of IHS Markit economic driver forecast; whereas the 2021 IRP relied on the October 2019 release from IHS Markit. Figure A.3 shows the weather normalized average system residential use per customer.

Figure A.3 – PacifiCorp Annual Residential Use per Customer 2001 through 2021



Weather

The Company's load forecast is based on historical actual weather adjusted for expectations and impacts from climate change. The historical weather is defined by the 20-year period of 2002 through 2021. The climate change weather uses the data from the historical period and adjusts the percentile of the data to achieve the expected target average annual temperature and calculate the HDD and CDD impacts and peak producing weather impacts within the energy forecast and peak forecast, respectively.

The climate change weather target temperature relies on actual 1990 average temperatures and projected temperature increases over 1990 average temperatures as determined by the United States Bureau of Reclamation (Reclamation) in the West-Wide Climate Risk Assessments: Hydroclimate Projections Study (Study).[2] The Company determined daily average temperatures and peak producing temperatures that correspond to the midpoint of the projected temperature increase between the Representative Concentration Pathway (RCP) 4.5 and RCP 8.5 ranges in the Study.

[2] United States Bureau of Reclamation, March 2021, Managing Water in the West, Technical Memorandum No. ENV-2021-001, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2021secure/westwidesecurereport1-2.pdf

Table A.5 – Projected Range of Temperature Change in the 2020s and 2050s relative to the 1990s[3]

Bureau of Reclamation Site	PacifiCorp Jurisdiction Assumption	Projected Range of Temperature Change (°F)*	
		2020s	2050s
Klamath River near Klamath	California	1.7 to 2.6	3.6 to 5.2
Snake River Near Heise	Idaho	1.6 to 3.0	4.1 to 5.9
Klamath River near Seiad Valley	Oregon	1.8 to 2.7	3.7 to 5.3
Green River near Greendale	Utah	1.8 to 3.3	4.2 to 6.3
Yakima River at Parker	Washington	1.8 to 2.8	3.6 to 5.6
Green River near Greendale	Wyoming	1.8 to 3.3	4.2 to 6.3

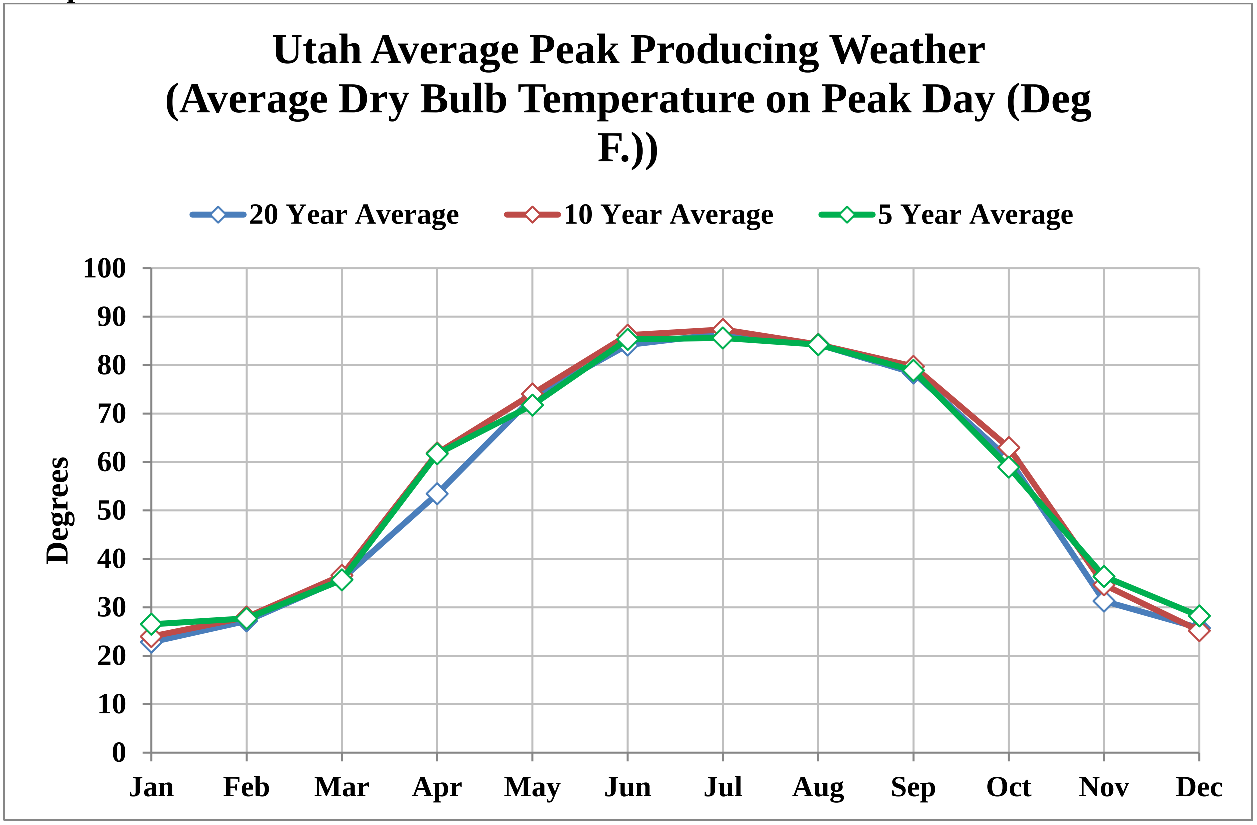
*Lower bound of temperature projections based on RCP 4.5, while upper bound based on RCP 8.5

In addition to climate change weather discussed above, the Company has reviewed the appropriateness of using the average weather from a shorter time period as its "normal" peak weather. Figure A.4 indicates that peak producing weather does not change significantly when comparing five, 10, or 20-year average weather.

The Company also updated its temperature spline models to the five-year time period of October 2016 – September 2021. The Company's spline models are used to model the commercial, residential and irrigation class temperature sensitivity at varying temperatures.

[3] Ibid.

Figure A.4 – Comparison of Utah 5, 10, and 20-Year Average Peak Producing Temperatures



Statistically Adjusted End-Use ("SAE")

The Company models sales per customer for the residential class using the SAE model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price. The Company uses ITRON for its load forecasting software and services, as well as the SAE. To predict future changes in the efficiency of the various end uses for the residential class, an excel spreadsheet model obtained from ITRON was utilized; the model includes appliance efficiency trends based on appliance life as well as past and future efficiency standards. The model embeds all currently applicable laws and regulations regarding appliance efficiency, along with life cycle models of each appliance. The life cycle models, based on the decay and replacement rate are necessary to estimate how fast the existing stock of any given appliance turns over, i.e. newer more efficient equipment replacing older less efficient equipment. The underlying efficiency data is based on estimates of energy efficiency from the US Department of Energy's Energy Information Administration (EIA). The EIA estimates the efficiency of appliance stocks and the saturation of appliances at the national level and for individual Census Regions.

Individual Customer Forecast

The Company updated its load forecast for a select group of large industrial customers, self-generation facilities of large industrial customers, and data center forecasts within the respective jurisdictions. Customer forecasts are provided by the customer to the Company through a regional business manager (“RBM”).

Actual Load Data

With the exception to the industrial class, the Company uses actual load data from January 2000 through February 2022. The historical data period used to develop the industrial monthly sales forecast is from January 2000 through February 2022 in Utah, Wyoming, and Washington, January 2002 through February 2022 in Idaho, and January 2003 through February 2022 in California and January 2008 through February 2022 in Oregon.

The following tables are the annual actual retail sales, non-coincident peak, and coincident peak by state used in calculating the 2023 IRP retail sales forecast.

Table A.6 – Weather Normalized Jurisdictional Retail Sales 2000 through 2021

System Retail Sales - Megawatt-hours (MWh)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	770,820	3,116,508	13,850,006	18,970,364	4,084,537	7,411,248	**48,203,483**
2001	768,864	3,005,141	13,392,332	18,559,167	3,995,989	7,652,997	**47,374,489**
2002	791,735	3,256,168	12,957,060	18,630,359	3,992,241	7,429,503	**47,057,066**
2003	812,166	3,269,807	12,939,631	19,281,125	4,041,618	7,426,913	**47,771,259**
2004	835,515	3,333,624	13,058,719	19,892,658	4,073,666	7,793,618	**48,987,800**
2005	827,540	3,285,758	13,059,825	20,363,787	4,183,226	7,993,309	**49,713,446**
2006	848,726	3,346,052	13,774,581	21,187,643	4,108,566	8,209,339	**51,474,907**
2007	866,742	3,425,039	13,871,720	22,086,852	4,053,437	8,504,273	**52,808,062**
2008	857,500	3,444,347	13,135,644	22,715,811	4,052,529	9,203,352	**53,409,183**
2009	819,819	2,979,003	12,970,802	22,146,938	4,024,282	9,256,870	**52,197,714**
2010	835,326	3,468,573	13,046,266	22,590,597	4,023,412	9,648,267	**53,612,440**
2011	797,736	3,493,098	12,891,100	23,406,694	3,994,623	9,792,857	**54,376,107**
2012	776,608	3,543,173	12,902,817	23,692,760	4,017,534	9,469,443	**54,402,334**
2013	766,445	3,586,627	12,955,649	23,770,781	4,029,058	9,533,401	**54,641,961**
2014	763,083	3,574,849	13,044,614	24,245,893	4,074,243	9,587,020	**55,289,702**
2015	732,905	3,532,641	13,044,577	24,008,248	4,064,376	9,360,103	**54,742,851**
2016	745,142	3,495,674	13,203,510	23,655,727	4,012,667	9,191,271	**54,303,991**
2017	749,028	3,608,590	13,230,882	23,807,001	4,044,195	9,331,829	**54,771,525**
2018	733,383	3,641,048	13,190,422	24,586,138	4,030,934	9,243,563	**55,425,488**
2019	735,995	3,530,085	13,272,614	24,527,670	4,022,640	9,317,139	**55,406,143**
2020	755,926	3,596,981	13,179,949	24,703,889	4,074,386	8,317,048	**54,628,180**
2021	787,505	3,534,599	13,698,449	25,272,678	4,108,739	8,494,257	**55,896,227**
Compound Annual Growth Rate							
2000-21	**0.10%**	**0.60%**	**-0.05%**	**1.38%**	**0.03%**	**0.65%**	**0.71%**

*System retail sales do not include sales for resale

Table A.7 – Non-Coincident Jurisdictional Peak 2000 through 2021

Non-Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	176	686	2,603	3,684	785	1,061	**8,995**
2001	162	616	2,739	3,480	755	1,124	**8,876**
2002	174	713	2,639	3,773	771	1,113	**9,184**
2003	169	722	2,451	4,004	788	1,126	**9,260**
2004	193	708	2,524	3,862	920	1,111	**9,317**
2005	189	753	2,721	4,081	844	1,224	**9,811**
2006	180	723	2,724	4,314	822	1,208	**9,970**
2007	187	789	2,856	4,571	834	1,230	**10,466**
2008	187	759	2,921	4,479	923	1,339	**10,609**
2009	193	688	3,121	4,404	917	1,383	**10,705**
2010	176	777	2,552	4,448	893	1,366	**10,213**
2011	177	770	2,686	4,596	854	1,404	**10,486**
2012	159	800	2,550	4,732	797	1,337	**10,376**
2013	182	814	2,980	5,091	886	1,398	**11,351**
2014	161	818	2,598	5,024	871	1,360	**10,831**
2015	157	843	2,598	5,226	837	1,326	**10,986**
2016	155	848	2,584	5,018	819	1,300	**10,724**
2017	177	830	2,920	4,932	943	1,354	**11,156**
2018	158	830	2,608	5,091	849	1,319	**10,854**
2019	151	793	2,632	5,158	895	1,363	**10,993**
2020	155	806	2,562	5,336	848	1,271	**10,979**
2021	149	771	2,894	5,547	938	1,299	**11,598**
Compound Annual Growth Rate							
2000-21	**-0.77%**	**0.56%**	**0.51%**	**1.97%**	**0.85%**	**0.96%**	**1.22%**

*Non-coincident peaks do not include sales for resale

Table A.8 – Jurisdictional Contribution to Coincident Peak 2000 through 2021

Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	154	523	2,347	3,684	756	979	**8,443**
2001	124	421	2,121	3,479	627	1,091	**7,863**
2002	162	689	2,138	3,721	758	1,043	**8,511**
2003	155	573	2,359	4,004	774	1,022	**8,887**
2004	120	603	2,200	3,831	740	1,094	**8,588**
2005	171	681	2,238	4,015	708	1,081	**8,895**
2006	156	561	2,684	3,972	816	1,094	**9,283**
2007	160	701	2,604	4,381	754	1,129	**9,730**

2008	171	682	2,521	4,145	728	1,208	**9,456**
2009	153	517	2,573	4,351	795	987	**9,375**
2010	144	527	2,442	4,294	757	1,208	**9,373**
2011	143	549	2,187	4,596	707	1,204	**9,387**
2012	156	782	2,163	4,731	749	1,225	**9,806**
2013	156	674	2,407	5,091	797	1,349	**10,474**
2014	150	630	2,345	5,024	819	1,294	**10,263**
2015	152	805	2,472	5,081	833	1,259	**10,601**
2016	139	575	2,462	4,940	817	1,201	**10,135**
2017	152	593	2,547	4,911	787	1,306	**10,296**
2018	126	741	2,526	5,037	790	1,295	**10,514**
2019	122	731	2,276	5,158	761	1,248	**10,297**
2020	127	603	2,428	5,336	839	1,180	**10,515**
2021	145	767	2,543	5,319	839	1,214	**10,827**
Compound Annual Growth Rate							
2000-21	**-0.29%**	**1.84%**	**0.38%**	**1.76%**	**0.50%**	**1.03%**	**1.19%**

*Coincident peaks do not include sales for resale

System Losses

Line loss factors are derived using the five-year average of the percent difference between the annual system load by jurisdiction and the retail sales by jurisdiction. System line losses were updated to reflect actual losses for the five-year period ending December 31, 2021.

Forecast Methodology Overview

Demand-side Management Resources in the Load Forecast

PacifiCorp modeled as a resource option to be selected as part of a cost-effective portfolio resource mix using the Company's Plexos capacity expansion optimization model. The load forecast used for IRP portfolio development excluded forecasted load reductions from energy efficiency ; Plexos then determines the amount of energy efficiency —expressed as supply curves that relate incremental DSM quantities with their costs—given the other resource options and inputs included in the model. The use of energy efficiency supply curves, along with the economic screening provided by Plexos, determines the cost-effective mix of energy efficiency for a given scenario.

Modeling overview

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential sales forecast is developed as a use-per-customer forecast multiplied by the forecasted number of customers.

The customer forecasts are based on a combination of regression analysis and exponential smoothing techniques using historical data from January 2000 to February 2022. For the residential class, the Company forecasts the number of customers using IHS Markit's forecast of each state's population or number of households as the major driver.

The Company uses a differenced model approach in the development of the residential customer forecast. Rather than directly forecasting the number of customers, the differenced model predicts the monthly change in number of customers.

The Company models sales per customer for the residential class using the SAE model discussed above, which combines the end-use modeling concepts with traditional regression analysis techniques.

For the commercial class, the Company forecasts sales using regression analysis techniques with non-manufacturing employment and non-farm employment designated as the major economic drivers, in addition to weather-related variables. Monthly sales for the commercial class are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers. The development of the forecast of monthly commercial sales involves an additional step; to reflect the addition of a large "lumpy" change in sales such as a new data center, monthly commercial sales are increased based on input from the Company's RBM's. The treatment of large commercial additions is similar to the methodology for large industrial customer sales, which is discussed below.

Monthly sales for irrigation and street lighting are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers.

The majority of industrial sales are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver in all states with exception of Utah, in which an Industrial Production Index is used. For a small number of the very largest industrial customers, the Company prepares individual forecasts based on input from the customer and information provided by the RBM's.

After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps. First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak-producing weather for each state and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. The weather variables include the average temperature on the peak day and lagged average temperatures from up to two days before the day of the forecast. The peak forecast is based on the climate change peak-producing weather discussed above.

Second, the Company develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures for the 20-year period 2002 through 2021, a typical annual weather pattern, and day-type variables such as weekends and holidays as inputs to the model. The hourly loads are adjusted to match the monthly peaks from the first step above. Hourly loads are then adjusted so the monthly sum of hourly loads equals monthly sales plus line losses.

After the hourly load forecasts are developed for each state, hourly loads are aggregated to the total system level. The system coincident peaks can then be identified, as well as the contribution of each jurisdiction to those monthly peaks.

Electrification Adjustments

The load forecast used for 2023 IRP portfolio development includes the Company's expectations for transportation electrification based on current and expected electric-vehicle (EV) adoption trends. These projections were incorporated as a post-model adjustment to the residential and commercial sales forecasts.

Vehicle adoption and load impacts vary by state depending on a variety of socioeconomic factors and policies particular to each state. To develop a prospective forecast of EV adoption, PacifiCorp developed a model to assess trends for light-duty EVs and medium-duty EVs. To develop a future EV adoption curve, the Company reviewed three national EV forecasts, each representing varying degrees of aggressiveness. While these forecasts represent national trends, the adoption curves themselves can be applied and adapted to state-specific parameters to reflect current market conditions in the state. The Company calibrates each adoption curve source to base inputs from EIA's Annual Energy Outlook (AEO) projections and estimated historical vehicle actuals. The AEO inputs include estimated shares of battery electric vehicles and plug-in hybrid electric vehicles as well as light-duty vehicles and light-duty trucks. Each of the national adoption curve sources is discussed below to help contextualize the various sources reviewed for this plan's EV adoption forecast.

The load forecast also incorporates the Company's expectations for building electrification initiatives. In the near-term, building electrification is relatively minor share of load but is expected to grow over time as state and national policies encouraging fuel substitution and electrification become more prevalent. The Company's building electrification forecast is based on expected fuel shares for space heating and water heating equipment at the end of its useful life and future new construction shares of electric fuel for these end-uses over time. Adoption curves are calibrated to expected equipment turnover and new construction rates in alignment with assumptions used in the Conservation Potential Assessment. Adoption curves and timing of building electrification is estimated based on the state specific policies or known market trends supporting advancement of building electrification.

The Company continually assesses both transportation and building electrification market trends, policies, and adoptions levels in each state. As these markets evolve, the Company will continue to update forecasts to reflect new trends as they occur.

Sales Forecast at the Customer Meter

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 Preferred Portfolio.

Table A.9 – System Annual Retail Sales Forecast 2021 through 2032, post-DSM

System Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	17,361,583	20,978,789	18,760,385	1,472,103	98,858	**58,671,719**
2024	17,561,027	23,333,643	18,912,628	1,463,717	95,519	**61,366,533**
2025	17,663,790	24,565,976	19,192,595	1,455,086	92,615	**62,970,063**
2026	17,860,209	25,344,020	17,755,233	1,449,220	90,685	**62,499,366**
2027	18,075,462	27,203,257	17,720,663	1,442,125	89,172	**64,530,679**
2028	18,386,033	30,063,031	17,769,947	1,434,670	88,119	**67,741,799**
2029	18,633,432	30,372,554	17,700,916	1,426,506	86,618	**68,220,026**
2030	18,972,662	30,145,257	17,751,969	1,419,207	85,392	**68,374,488**
2031	19,332,679	30,522,754	17,739,953	1,412,108	84,220	**69,091,714**
2032	19,852,639	30,155,847	17,782,332	1,403,445	83,419	**69,277,682**
Compound Annual Growth Rate						
2023-32	1.50%	4.11%	-0.59%	-0.53%	-1.87%	1.86%

Residential

The average annual growth of the residential class sales forecast increased from 0.80 percent in the 2021 IRP to 1.50 percent in the 2023 IRP. The number of residential customers across PacifiCorp’s system is expected to grow at an annual average rate of 1.48 percent, reaching approximately 2.06 million customers in 2032, with Rocky Mountain Power states adding 1.82 percent per year and Pacific Power states adding 0.92 percent per year.

Commercial

Average annual growth of the commercial class sales forecast increased from 1.04 percent annual average growth in the 2021 IRP to 4.11 percent in the 2023 IRP. The number of commercial customers across PacifiCorp’s system is expected to grow at an annual average rate of 0.90 percent, reaching approximately 246,000 customers in 2032, with Rocky Mountain Power states adding 1.18 percent per year and Pacific Power states adding 0.52 percent per year.

Industrial

Average annual growth of the industrial class sales forecast decreased from -0.11 percent annual average growth in the 2021 IRP to -0.59 percent expected annual growth in the 2023 IRP. A portion of the Company’s industrial load is in the extractive industry in Utah and Wyoming; therefore, changes in commodity prices can impact the Company’s load forecast.

State Summaries

Oregon

Table A.10 – Forecasted Retail Sales Growth in Oregon, post-DSM summarizes Oregon state forecasted retail sales growth by customer class.

Table A.10 – Forecasted Retail Sales Growth in Oregon, post-DSM

Oregon Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	5,776,140	6,971,569	1,458,214	270,754	29,920	14,506,597
2024	5,813,544	8,727,403	1,466,594	270,264	29,236	16,307,041
2025	5,806,005	9,761,216	1,495,283	269,413	28,514	17,360,433
2026	5,840,308	10,246,092	1,489,796	269,210	28,009	17,873,416
2027	5,887,124	11,251,088	1,475,161	268,963	27,619	18,909,955
2028	5,974,783	12,561,821	1,461,575	268,836	27,405	20,294,420
2029	6,054,951	12,820,090	1,455,444	268,381	27,108	20,625,973
2030	6,172,566	12,677,326	1,453,566	268,029	26,950	20,598,436
2031	6,314,070	13,084,453	1,459,414	267,642	26,835	21,152,414
2032	6,495,531	13,089,511	1,476,758	267,370	26,832	21,356,002
Compound Annual Growth Rate						
2023-32	**1.31%**	**7.25%**	**0.14%**	**-0.14%**	**-1.20%**	**4.39%**

Washington

Table A.11 – Forecasted Retail Sales Growth in Washington, post-DSM summarizes Washington state forecasted retail sales growth by customer class.

Table A.11 – Forecasted Retail Sales Growth in Washington, post-DSM

Washington Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	1,569,912	1,569,506	828,111	161,366	3,294	**4,132,188**
2024	1,575,457	1,581,008	825,124	159,738	3,231	**4,144,559**
2025	1,566,405	1,568,866	812,588	158,750	3,199	**4,109,809**
2026	1,566,847	1,564,706	802,531	158,297	3,192	**4,095,573**
2027	1,567,629	1,565,138	796,393	157,806	3,190	**4,090,156**
2028	1,575,315	1,567,825	794,158	157,247	3,200	**4,097,744**
2029	1,574,971	1,559,991	789,614	156,835	3,190	**4,084,601**
2030	1,580,219	1,556,026	787,560	156,474	3,190	**4,083,470**
2031	1,585,479	1,555,833	787,983	156,415	3,190	**4,088,900**
2032	1,596,353	1,556,759	788,347	156,000	3,199	**4,100,658**
Compound Annual Growth Rate						
2023-32	**0.19%**	**-0.09%**	**-0.55%**	**-0.38%**	**-0.32%**	**-0.09%**

California

Table A.12 - Forecasted Retail Sales Growth in California, post-DSM summarizes California state forecasted sales growth by customer class.

Table A.6 - Forecasted Retail Sales Growth in California, post-DSM

California Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	377,233	238,946	54,997	97,232	1,628	770,037
2024	377,131	237,264	53,389	96,630	1,600	766,014
2025	374,277	233,240	52,235	96,229	1,569	757,549
2026	372,480	230,331	51,812	96,016	1,549	752,188
2027	370,942	228,808	51,440	95,783	1,534	748,507
2028	370,818	227,945	51,185	95,583	1,527	747,058
2029	368,319	225,742	50,735	95,268	1,515	741,578
2030	366,926	224,681	50,478	95,019	1,509	738,613
2031	365,606	223,441	50,232	94,649	1,504	735,432
2032	365,968	223,270	50,189	94,220	1,506	735,153
Compound Annual Growth Rate						
2023-32	**-0.34%**	**-0.75%**	**-1.01%**	**-0.35%**	**-0.86%**	**-0.51%**

Utah

Table A.13 – Forecasted Retail Sales Growth in Utah, post-DSM summarizes Utah state forecasted sales growth by customer class.

Table A.7 – Forecasted Retail Sales Growth in Utah, post-DSM

Utah Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	7,835,131	10,246,229	8,137,068	233,429	49,506	26,501,364
2024	7,986,696	10,832,402	8,238,305	230,300	47,036	27,334,739
2025	8,119,480	11,064,958	8,233,901	227,009	45,163	27,690,511
2026	8,284,098	11,384,983	6,807,862	223,609	44,067	26,744,620
2027	8,454,824	12,261,214	6,827,830	219,645	43,400	27,806,913
2028	8,665,353	13,820,108	6,843,943	215,282	43,126	29,587,812
2029	8,844,710	13,908,034	6,817,082	210,766	42,770	29,823,362
2030	9,066,276	13,850,077	6,834,566	206,189	42,633	29,999,741
2031	9,287,214	13,845,537	6,834,089	201,514	42,554	30,210,908
2032	9,613,627	13,483,845	6,814,215	195,865	42,630	30,150,181
Compound Annual Growth Rate						
2023-32	**2.30%**	**3.10%**	**-1.95%**	**-1.93%**	**-1.65%**	**1.44%**

Idaho

Table A.14 - Forecasted Retail Sales Growth in Idaho, post-DSM summarizes Idaho state forecasted sales growth by customer class.

Table A.8 - Forecasted Retail Sales Growth in Idaho, post-DSM

Idaho Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	793,909	551,520	1,770,789	679,642	2,641	3,798,500
2024	804,094	554,572	1,736,293	677,301	2,625	3,774,885
2025	806,682	552,218	1,736,660	674,431	2,594	3,772,585
2026	811,343	549,260	1,735,986	672,973	2,571	3,772,133
2027	815,138	545,183	1,734,061	670,967	2,547	3,767,897
2028	820,769	542,345	1,732,080	668,926	2,531	3,766,652
2029	819,247	534,579	1,728,504	666,588	2,502	3,751,419
2030	820,297	527,445	1,726,072	664,917	2,480	3,741,211
2031	820,173	519,098	1,724,099	663,366	2,460	3,729,196
2032	823,076	514,464	1,722,624	661,563	2,447	3,724,174
Compound Annual Growth Rate						
2023-32	**0.40%**	**-0.77%**	**-0.31%**	**-0.30%**	**-0.84%**	**-0.22%**

Wyoming

Table A.15 – Forecasted Retail Sales Growth in Wyoming, post-DSM summarizes Wyoming state forecasted sales growth by customer class.

Table A.9 – Forecasted Retail Sales Growth in Wyoming, post-DSM

Wyoming Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2023	1,009,258	1,401,020	6,511,205	29,679	11,870	8,963,032
2024	1,004,104	1,400,993	6,592,922	29,485	11,791	9,039,295
2025	990,941	1,385,479	6,861,929	29,252	11,575	9,279,176
2026	985,132	1,368,647	6,867,245	29,115	11,297	9,261,436
2027	979,805	1,351,827	6,835,777	28,961	10,882	9,207,251
2028	978,994	1,342,988	6,887,006	28,797	10,329	9,248,113
2029	971,235	1,324,118	6,859,538	28,668	9,534	9,193,092
2030	966,378	1,309,701	6,899,728	28,579	8,631	9,213,017
2031	960,137	1,294,392	6,884,136	28,522	7,676	9,174,863
2032	958,085	1,287,998	6,930,199	28,427	6,805	9,211,514
Compound Annual Growth Rate						
2023-32	**-0.58%**	**-0.93%**	**0.70%**	**-0.48%**	**-5.99%**	**0.30%**

Alternative Load Forecast Scenarios

The purpose of providing alternative load forecast cases is to determine the resource type and timing impacts resulting from a change in the economy or system peaks as a result of varying temperatures and economic conditions.

The May 2022 forecast is the baseline scenario. For the high and low load growth scenarios, optimistic and pessimistic economic driver assumptions from IHS Markit were applied to the economic drivers in the Company's load forecasting models. These growth assumptions were extended for the entire forecast horizon. Further, the high and low load growth scenarios also incorporate the standard error bands for the energy and the peak forecast to determine a 95% prediction interval around the base IRP forecast. Lastly, the high scenario incorporates the Company's low private generation forecast, while the low scenario incorporates the high private generation forecast.

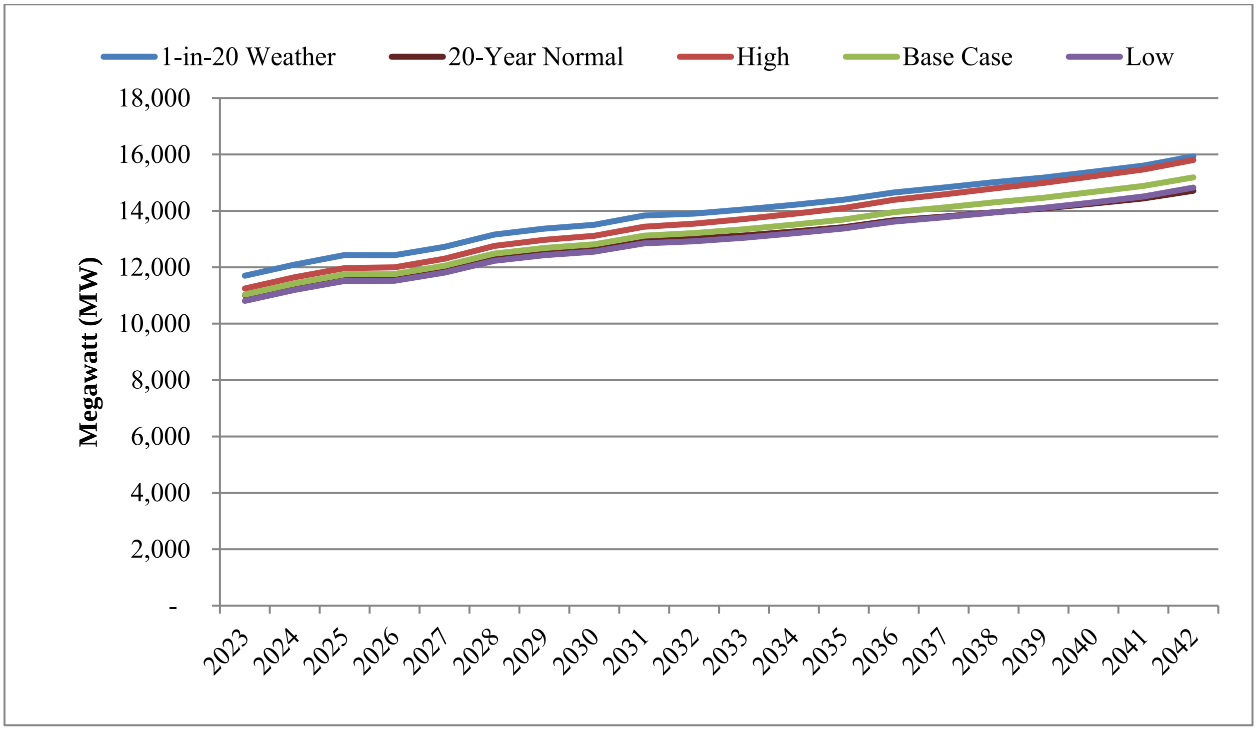
The 95% prediction interval is calculated at the system level and then allocated to each state and class based on their contribution to the variability of the system level forecast. The standard error bands for the jurisdictional peak forecasts were calculated in a similar manner. The final high load growth scenario includes the optimistic economic forecast and low private generation forecast plus the monthly energy adder and the monthly peak forecast with the peak adder. The final low load growth scenario includes the pessimistic economic forecast and high private generation forecast minus the monthly energy adder and monthly peak forecast minus the peak adder.

For the 1-in-20 year (5 percent probability) extreme weather scenario, the Company used 1-in-20 year peak weather for summer (July) months for each state. The 1-in-20 year peak weather is defined as the year for which the peak has the chance of occurring once in 20 years.

The 20-year normal scenario is based on normal weather, which is defined by the 20-year time period of 2002 through 2021 (50th percentile). In prior IRP cycles, this scenario is what was traditionally used as the base IRP load forecast.

Figure A.5 shows the comparison of the above scenarios relative to the Base Case scenario.

Figure A.5 – Load Forecast Scenarios, pre-DSM



APPENDIX B - REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2023 Integrated Resource Plan (IRP) complies with (1) the various state commission IRP standards and guidelines, (2) specific analytical requirements stemming from acknowledgment orders for the company's 2021 Integrated Resource Plan, and other ongoing IRP acknowledgement order requirements as applicable, and (3) state commission IRP requirements stemming from other regulatory proceedings.

Included in this appendix are the following tables:

- Table B.1 - Provides an overview and comparison of the rules in each state for which IRP submission is required.[33]
- Table B.2 - Provides a description of how PacifiCorp addressed the 2021 IRP acknowledgement order requirements and other commission directives.
- Table B.3 - Provides an explanation of how this plan addresses each of the items contained in the Oregon IRP guidelines.
- Table B.4 - Provides an explanation of how this plan addresses each of the items contained in the Public Service Commission of Utah IRP Standard and Guidelines issued in June 1992.
- Table B.5 - Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and Transportation Commission IRP rules issued in December 2020 in WAC 480-100-620.
- Table B.6 - Provides an explanation of how this plan addresses each of the items contained in the Wyoming Public Service Commission IRP guidelines updated in March 2016.

General Compliance

PacifiCorp prepares the IRP on a biennial basis and files the IRP with state commissions. The preparation of the IRP is done in an open public process with consultation from all interested parties, including commissioners and commission staff, customers, and other stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process, and serves to inform all parties on the planning issues and approach. The public input process for this IRP will be described in Volume I, Chapter 2 (Introduction), as well as Volume II, Appendix C (Public) Input fully complies with IRP standards and guidelines.

[33] 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.

The IRP provides a framework and plan for future actions to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP evaluates, over a twenty-year planning period, the future load of PacifiCorp customers and the resources required to meet this load.

To fill any gap between changes in loads and existing resources, while taking into consideration potential early retirement of existing coal units as an alternative to investments that achieve compliance with environmental regulations, the IRP evaluates a broad range of available resource options, as required by state commission rules. These resource options include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results) meets this requirement and 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. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP standards and guidelines, and is described in detail in Volume I, Chapter 8 – Modeling and Portfolio Evaluation.

The IRP analysis is designed to define a resource plan that is least-cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual carbon dioxide (CO_2) emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).

Consistent with the IRP standards and guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan in Volume I, Chapter 10 (Action Plan). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. The Action Plan also provides a progress report on action items contained in the 2021 IRP.

The 2023 IRP and related Action Plan are filed with each commission with a request for acknowledgment or acceptance, as applicable. Acknowledgment or acceptance means that a commission recognizes the IRP as meeting all regulatory requirements at the time of acknowledgment. In a case where a commission acknowledges the IRP in part or not at all, PacifiCorp may modify and seek to re-file an IRP that meets their acknowledgment standards or address any deficiencies in the next plan.

State commission acknowledgment orders or letters typically stress that an acknowledgment does not indicate approval or endorsement of IRP conclusions or analysis results. Similarly, an acknowledgment does not imply that favorable ratemaking treatment for resources proposed in the IRP will be given.

California

Public Utilities Code Section 454.52, mandates that the California Public Utilities Commission (CPUC) adopt a process for load serving entities to file an IRP beginning in 2017. In February 2016, the CPUC opened a rulemaking to adopt an IRP process and address the scope of the IRP to be filed with the CPUC (Docket R.16-02-007).

Decision (D.) 18-02-018 instructed PacifiCorp to file an alternative IRP consisting of any IRP submitted to another public regulatory entity within the previous calendar year (Alternative Type 2 Load Serving Entity Plan). D.18-02-018 also instructed PacifiCorp to provide an adequate description of treatment of disadvantaged communities, as well as a description of how planned future procurement is consistent with the 2030 Greenhouse Gas Benchmark.

PacifiCorp also provides its IRP and an IRP Supplement in lieu of providing a Renewables Portfolio Standard Procurement Plan, as authorized by Public Utilities Code Section 399.17(d). Requirements for PacifiCorp's IRP Supplement are outlined in an annual Assigned Commissioner's Ruling from the CPUC[1] and D.22-12-030 issued on December 19, 2022, approving the company's 2021 IRP Supplement (2022 Off-Year Supplement to its 2021 IRP).

On October 18, 2019, PacifiCorp submitted its 2019 IRP in compliance with D.18-02-018.

On April 6, 2020, the CPUC issued D.20-03-028, which reiterated PacifiCorp's ability to file an alternative IRP.

On September 1, 2021, PacifiCorp filed its 2021 IRP in Docket R.18-07-003 in compliance with D.08-05-029.

On November 1, 2022, PacifiCorp filed its 2021 IRP in Docket R.20-05-003 in compliance with D.18-02-018, D.20-03-028, and D.22-02-004.

On January 18, 2023, PacifiCorp filed its 2021 IRP Supplement (2022 Off-Year Supplement to its 2021 IRP) in Docket R.18-07-003 in compliance with D.08-05-029 and D.22-12-030.

Idaho

The Idaho Public Utilities Commission's (Idaho PUC) Order No. 22299, issued in January 1989, specifies integrated resource planning requirements. This order mandates that PacifiCorp submit a Resource Management Report (RMR) on a biennial basis. The intent of the RMR is to describe the status of IRP efforts in a concise format, and cover the following areas:

> *Each utility's RMR should discuss any flexibilities and analyses considered during comprehensive resource planning, such as: (1) examination of load forecast uncertainties; (2) effects of known or potential changes to existing resources; (3)*

[1] The most recent Assigned Commissioner's Ruling is the *Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying issues and Schedules of Review for 2022 Renewables Portfolio Standard Procurement Plans and Denying Joint IOU's Motion to File Advice Letters for Market Offer Process¸ Rulemaking 18-07-003 (April 11, 2022).*

consideration of demand and supply side resource options; and (4) contingencies for upgrading, optioning and acquiring resources at optimum times (considering cost, availability, lead time, reliability, risk, etc.) as future events unfold.

This IRP is submitted to the Idaho PUC as the Resource Management Report for 2023, and fully addresses the above report components.

Oregon

This IRP is submitted to the Oregon Public Utility Commission (OPUC) in compliance with its planning guidelines issued in January 2007 (Order No. 07-002). The Oregon PUC's IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8, Order No. 08-339), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), resource acquisition (Guideline 13), and flexible resource capacity (Order No. 12-013). Consistent with the earlier guidelines (Order 89-507[2]), the Oregon PUC notes that acknowledgment does not guarantee favorable ratemaking treatment, only that the plan seems reasonable at the time acknowledgment is given. Table B provides detail on how this plan addresses each of the requirements.

Utah

This IRP is submitted to the Public Service Commission of Utah in compliance with its 1992 Order on Standards and Guidelines for Integrated Resource Planning (Docket No. 90-2035-01, "Report and Order on Standards and Guidelines"). Table B documents how PacifiCorp complies with each of these standards.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring a two-year progress report of the previously filed plan, which was the Company's 2021 IRP (Washington Administrative Code 480-100-625) (effective, December 2020).

In its report, the rule requires PacifiCorp to include an update of its load forecast; demand-side resource assessment, including new conservation potential assessment; resource costs; and the portfolio analysis and preferred portfolio. The report must also include other updates that are necessary due to changing state or federal requirements, or significant changes to economic or market forces; and an update for any elements found in the Company's current Clean Energy Implementation Plan (CEIP). Please refer to Appendix O (Washington Two-year Progress Report Additional Elements) for additional detail regarding updates to elements of the Company's CEIP.

Wyoming

Wyoming Public Service Commission issued new rules that replaced the previous set of rules on

[2] Public Utility Commission of Oregon, Order No. 12-013, Docket No. 1461, January 19, 2012.

March 21, 2016. Chapter 3, Section 33 outlines the requirements on filing IRPs for any utility serving Wyoming customers. The rule, shown below, went into effect in March 2016.

Table B.1 provides detail on how this plan addresses the rule requirements.

> ***Section 33. Integrated Resource Plan (IRP).***
> *Each utility serving in Wyoming that files an IRP in another jurisdiction shall file that IRP with the Commission. The Commission may require any utility to file an IRP.*

Table B.1 – Integrated Resource Planning Standards and Guidelines Summary by State

Topic	Oregon	Utah	Washington	Idaho	Wyoming
Source	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.	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 *Least Cost Planning Rulemaking*, January 9, 2006 (Docket # UE-030311). Commission General Order R-601 further adopted IRP rules compliant with CETA.	Order 22299 *Electric Utility Conservation Standards and Practices* January 1989.	Wyoming Electric, Gas and Water Utilities, Chapter 3, Section 33, March 21, 2016.
Filing Requirements	Least-cost plans must be filed with the Oregon PUC.	An IRP is to be submitted to commission.	Submit a least cost plan to the WUTC. 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.

Frequency	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.
Commission Response	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. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP acknowledged if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	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.

Process	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. Involvement by the public in development of the plan is required. 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 work plan is to lay out the contents of the IRP, resource assessment method, and timing and extent of public participation.	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. 2000-346-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.
Focus	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, with short-term (two-year) action plan. The plan describes mix of resources sufficient to meet current and future loads at "lowest reasonable" cost to utility and ratepayers. 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.	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.

			As part of the IRP, utilities must develop a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050.		
Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis. • Risk and uncertainty must be considered. • The primary goal must be least cost, consistent with the long-run public interest. • The plan must be 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 transmission systems on an integrated-system basis. • Construction of resource portfolios over the range of	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, 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	The plan shall include: • A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses. • An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. • Assessment of a wide range of conventional and commercially available nonconventional generating technologies • An assessment of transmission system capability and reliability.	Discuss analyses considered including: • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options; • Contingencies for upgrading, optioning and acquiring resources at optimum times; • Report on existing resource stack, load forecast and additional resource menu.	Proposed Commission Staff guidelines issued July 2016 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 • Market purchase evaluation • Reserve margin analysis • Demand-side management and conservation options

	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.		• A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using "lowest reasonable cost" criteria. • An assessment and determination of resource adequacy metrics. • An assessment of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security risk • Integration of the demand forecasts and resource evaluations into a long-range (at least 10 years) plan. • All plans shall also include a progress report that relates the new plan to the previously filed plan. • Must develop a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050.		

			• The IRP must include a summary of substantive changes to modeling methodologies or inputs that result in changes to the utility's resource need, as compared to the utility's previous IRP. • The IRP must include an analysis and summary of the avoided cost estimate for energy, capacity, transmission, distribution, and greenhouse gas emissions costs. The utility must list nonenergy costs and benefits addressed in the IRP and should specify if they accrue to the utility, customers, participants, vulnerable populations, highly impacted communities, or the general public. • The utility must provide a summary of public comments received during the development of its IRP and the utility's responses, including whether issues raised in the comments were addressed and incorporated into the		

			final IRP as well as documentation of the reasons for rejecting any public input		

Table B.2 – Handling of 2021 IRP Acknowledgment and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
Idaho		
Order No. 35514 p. 17	We direct the Company, in its next IRP, to clarify whether a LOLH reliability target of 2.4 hours per year was achieved by the Company's portfolios and explain the development of FOT availability limits.	Because of limitations on computing power, the Company has not performed detailed hourly stochastic analysis so as to precisely determine the reliability of each of its portfolios. For reference, due to the complexity of the Company's portfolio and system operations, running one year of one study through 50 iterations could take a single computer upwards of a week. The Company's reliability assessment is intended to ensure that each portfolio achieves a comparable level of reliability. Because each study measures availability against requirements in every hour during the reliability assessment, all portfolios will logically achieve comparable reliability. Further, ENS measures support that this is the case. Discussion of the Company's FOT availability limits is provided in Chapter 5 (Reliability and Resiliency).
Order No. 35514 p. 17	We further direct the Company to clarify the issue of exceedance of FOT limits in the early years of the planning horizon as it pertains to the first deficit date for purposes of PURPA avoided cost rates and whether the inclusion of three percent contingency amounts for firm purchases were appropriate to include to meet Company load.	A discussion of exceedances in the first several years is provided in Chapter 5 (Reliability and Resiliency). Such exceedances are unavoidable as the Company pursues sufficient resources to reduce market reliance of the 20-year planning period. In actual operations, PacifiCorp must balance the risk of higher reliance on market purchases against the cost of procuring from a limited pool of resource options available in the very near term, rather than from a larger pool of resource options available in the next few years. That balancing will be a key consideration in PacifiCorp's ongoing 2022 All-Source Request for Proposals. As a result, forthcoming developments may be more pertinent to the question of deficit dates than the 2023 IRP itself. As detailed in Volume II, Appendix F (Flexible Reserve Study), to the extent the PacifiCorp's firm market purchases come from entities in other balancing authority areas, those entities will cover the contingency reserve obligation on the generation used to support the sale, and PacifiCorp's contingency reserve obligation will be reduced relative to what it would have been had it used its own generation to serve that portion of its load.

Order No. 35514 p. 17	While we understand the market realities of natural gas, 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.	PacifiCorp has included natural gas in its resource options per the supply-side resource table as developed throughout the public input meeting process. New gas options were not selected in the least-cost, least-risk methodology to develop the final preferred portfolio. PacifiCorp recognizes that many non-emitting technologies require technological progress to achieve the capabilities and costs assumed in the 2023 IRP, and will continue to consider technologies that are presently available. Because the Inflation Reduction Act provides tax credits only for non-emitting resources, gradually transitioning a new resource to a non-emitting fuel comes at a significant cost. See Volume I, Chapter 7 (Resource Options).
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, Natrium is anticipated to come online in the summer of 2030. The 2023 IRP includes two “no nuclear” variant studies 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.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
Oregon		
Order No. 22-178, p. 7	Require PacifiCorp to perform additional and more varied analyses regarding Jim Bridger Units 3 and 4, including a no minimum take analysis as suggested by Staff and Sierra Club and an analysis of endogenous retirement dates frequent enough to approximately match Staffs suggestion of allowing for retirement every two years.	In the 2023 IRP, retirements are optimized in every available year. As communicated during the 2023 public input meeting series and in response to feedback, no minimum take assumptions were assumed in Plexos modeling beyond present contracts. For Jim Bridger 3 and 4 this means the complete removal of minimum take provisions.
Order No. 22-178, p. 7	PacifiCorp is directed to file an updated long-term fuel plan for Jim Bridger with its 2023 IRP.	On March 28, 2023, the Commission granted PacifiCorp's request for an extension of time to submit the updated long-term fuel plan for Jim Bridger on May 31, 2023.
Order No. 22-178, p. 10	Consider how to ensure PacifiCorp has a complete and balanced portfolio given the current posture of the Natrium project.	In this cycle, Natrium is anticipated to come online in the summer of 2030. The 2023 IRP includes two "no nuclear" variant studies as described in Volume I, 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. 22-178, p. 11	In future IRPs, we expect PacifiCorp to articulate clearer justifications for its transmission projects, including how the company assessed transmission needs and alternatives comprehensively, how and why a particular project was selected in a transmission planning process, why it is reasonable for ratepayers to pay substantial costs for these particular projects, and what quantifiable (and quantified) and non-quantifiable (but valued qualitatively) benefits will come to Oregon ratepayers in particular and PacifiCorp ratepayers in general, as compared with benefits from regional projects that accrue to other regional actors not contributing to costs.	For the 2023 IRP, PacifiCorp evaluated transmission options based on the three cluster study outcomes completed thus far, as well as other analysis for locations not well-represented in the cluster study process. This represents the best available information regarding potential costs and resources. The addition of surplus and flexible hybrid resource options specifically allows the model to avoid transmission costs while increasing net generating capability at a given location using proportions of different technologies that are appropriate to a location and the needs of the portfolio as a whole. These options were modeled endogenously and in competition with a wide array of resources as detailed in multiple public input meetings. See Volume I, Chapter 4 (Transmission), and Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
Order No. 22-178, p. 12	We also expect PacifiCorp to produce the full cost information for the [transmission] projects we acknowledge today in the rate cases where it seeks to place them into rate base.	PacifiCorp is committed to giving full accounting in its rate case proceedings. For the 2023 IRP, summary cost information is provided in Volume I, Chapter 1 (Executive Summary), and expanded cost information is provided in workpapers.
Order No. 22-178, p. 13	In order to connect new resources to the grid, it is critical not only that transmission be built, but that the right transmission be built; the Commission and stakeholders need to have sufficient information to verify that ratepayers are getting the benefits they are paying for at each stage of development. Going forward, we expect PacifiCorp to provide information that allows that assessment at the outset. We also expect the company to actively encourage key stakeholders like Commission Staff and consumer advocates to participate and provide a larger window into its own transmission planning processes.	IRP modeling accounts for cost, location, total transfer capability and resource enabled by transmission options. Options are modeled endogenously, and selections are driven primarily by the need to increase interconnection to allow efficient system transfer and to serve load. In the 2023 IRP, costs, descriptions, and transfer capabilities are defined, and in addition near-term transfer options are rooted in cluster study and queue analysis and informed by surplus resource options which allow for transmission costs to be avoided where appropriate. The transmission option modeling strategy was discussed at three public input meetings spanning June 2022 through February 2023 with opportunities for feedback and recommendations. Also, modeling of scale renewable resources for Oregon's CEP assumes there are no accompanying transmission requirements, providing an additional opportunity to evaluate transmission avoidance beyond the native core functionality of the Plexos model. See Volume I, Chapter 4 (Transmission), and Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Order No. 22-178, p. 14	We direct PacifiCorp to forecast a likely QF contract renewal rate. Because PacifiCorp operates in a multi-state footprint, we understand this assessment to be more complicated than an Oregon-only renewal rate. However, PacifiCorp should use historical renewable rates as well as other relevant information in its possession and attempt to make its forecast as accurate as possible.	PacifiCorp used an analysis of historical rates to establish a 79% renewal rate, which was implemented in the 2023 IRP and presented at the September 1-2, 2022 public input meeting. The analysis can be viewed at this web link: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/QF_Extension_History_2012-2017-2022.xlsx. For the purpose of modeling in the 2023 IRP, each QF was assumed to have a 79% chance of renewing, so it is reduced to 79% of its current size upon reaching its current expiration date and then continues indefinitely.
Order No. 22-178, p. 14; Appx B p. 1	Develop and run a sensitivity that considers locations or online dates for large, flexible loads such as hydrogen electrolysis within the 2023 IRP. The parameters of the study would be further discussed in the 2023 IRP process. Such a sensitivity would consider optimal locations and years to include large amounts of highly flexible load, throughout the planning timeframe. We adopt this recommendation and note that there may be additional large loads, such as data centers, that fall under this recommendation too.	See Volume II, Appendix N: (Energy Storage Potential Evaluation) for analysis of potential hydrogen electrolysis load opportunities. PacifiCorp would note that with expected transmission builds and the sizeable quantity of energy storage on its system in the preferred portfolio, the difference in marginal prices by location is relatively small. While co-locating hydrogen electrolysis with renewable generation may have some benefits, it may be outweighed by the costs of transporting hydrogen to end users. In addition, the potential for flexible load is also represented in part through stochastic load variation and through seven load-related sensitivities. In addition to the 2023 IRP's four core load sensitivities (High load, Low Load, 1 in 20 Load and 20-year Normal Load) and two load-related sensitivities (High Private generation and Low Private Generation), PacifiCorp has also added a "New Load" sensitivity which contemplates an unanticipated large load addition to understand the impacts of such an occurrence. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results). PacifiCorp continues to evaluate how to usefully model larger amounts of flexible load.
Order No. 22-178, p. 15; Appx B p. 1	PacifiCorp to conduct a stakeholder process to determine what source the cost data in the 2023 IRP will rely on.	PacifiCorp's initial cost assumptions were provided at a workshop held on September 2, 2022 as part of its public input process. In addition, stakeholders participated in the decision to model offshore wind and associated transmission on a linear basis where any amount of a 1000 MW project could be selected assuming PacifiCorp could participate in partnership with other utilities. The decision was also made to allow other resources to compete for usage of the land-based transmission system upgrades necessary to enable offshore wind. An offshore wind counterfactual study was also run to determine the magnitude of the costs and benefits of offshore wind. See Volume I, Chapters 8 and 9.

Order No. 22-178, p. 15; Appx B p. 1	We expect PacifiCorp to engage in the company's local transmission planning process as appropriate and to request that sufficient information to inform consideration of offshore wind in future IRPs is made available in this local transmission study cycle.	PacifiCorp completed an Economic Study Request ("ESR"), submitted by the Oregon Public Utility Commission ("OPUC") Staff March 2022 to have PacifiCorp evaluate the effects of 1.0 GW of Offshore Wind (OSW) generation in southern Oregon, assumed to be interconnected to PacifiCorp's Del Norte substation located in Del Norte, California.
Order No. 22-178, p. 15; Appx B p. 2	PacifiCorp to review its pumped hydro proposals as part of its 2023 IRP public workshop series. PacifiCorp will perform a variety of analyses regarding pumped storage hydro … including a careful comparison with other possible pumped storage hydro projects, in the 2023 IRP … [and] sufficient information to be able to conclude that PacifiCorp has considered resources other than its own in this process.	The 2023 IRP considered seven proxy pumped hydro resource locations across the system. All seven use identical cost and size characteristics appropriate for proxy modeling, and cover at minimum four projects unassociated with PacifiCorp. As modeled, none of the projects are actual, and the Company is not modeling its own projects. Instead, the 2023 IRP represents pumped hydro storage as proxy resources. Every endogenous model run considers the selection of any or all of these resources among the multitude of competing options. Whether selected or not, pumped hydro projects are eligible to bid into PacifiCorp's all-source RFPs where determinations of which projects are contracted is decided by additional agnostic modeling of actual bids, potentially both benchmarks and market bids.
Order No. 22-178, p. 16; Appx B p. 2	In places where there are inconsistencies between the WRAP and the approach the IRP takes … we direct that the reasons for any discrepancies be explained by PacifiCorp.	The Western Resource Adequacy Program (WRAP) uses a series of Effective Load Carrying Capability (ELCC) analyses to identify the aggregate capacity contribution of wind, solar, and run-of-river hydro. Attribution of capacity to individual resources is based, in part, on a resource's generation during the top 5 percent net load hours, i.e. those hours in which the remaining load is highest after subtracting out wind and solar generation. The WRAP also uses a five-hour duration for determining the capacity contribution of energy-limited resources, like batteries. A five-hour or longer duration storage resource receives a 100% contribution, while shorter durations are prorated relative to five hours, such that a one-hour storage has a 20% contribution, while four-hour storage has an 80% contribution. There is significant uncertainty about storage duration requirements and they are necessarily portfolio dependent, so the WRAP will update its capacity contribution calculations each year. PacifiCorp does not have the detailed information about WRAP participants to perform the same calculations over the IRP study horizon. Instead, Volume I, Chapter 6 (Load and Resource Balance) presents portfolio contributions to capacity for PacifiCorp's 2023 IRP with capacity allocated among resources primarily based on generation during the

		top 5 percent net load hours, which was also part of the WRAP design. Because ELCC analyses require very data intensive studies with long run times, they have not been performed for the 2023 IRP load and resource reporting across the 20-year IRP horizon. Instead, the remaining capacity between the net load peak and the coincident peak, including the planning reserve margin was allocated among those resources with generation during the top 5 percent load hours that exceeded that during the top 5 percent net load hours. In addition to the above, PacifiCorp used the five-hour duration assumption from the WRAP for energy-limited resources at the start of the IRP planning horizon, but increased the required duration as more energy storage resources were added to the preferred portfolio, which emulates the likely outcomes in the WRAP.
Order No. 22-178, p. 16	Commissioners, Staff, or the Administrative Hearings Division will lead … a workshop to discuss increasing efficiency and demand response, including the consideration of a new, or updated, risk-reduction credit to efficiency.	Not applicable. PacifiCorp is supportive of the workshop and plans to participate as more details are known.
Order No. 22-178, p. 16; Appx B p. 2	Staff stated that it is supportive of PacifiCorp's plan to include peak time rebates in the 2023 CPA. If peak time rebates are determined to be cost-effective, PacifiCorp should further include an exploration of the potential to use a third-party vendor to implement a peak time rebate in advance of the new billing system implementation, in comparison to an approach that waits until the new billing system is implemented, as part of its 2023 IRP.	Engaging a consultant and preparing a study for a peak time rebate that would use the Company pre-existing billing system would be premature and duplicative at this time, because the Company is actively in the process of replacing its billing system. While AMI is a necessary precedent before deploying a peak time rebate program, an advanced billing system is also needed with an analytical engine that is capable of accurately billing customers on peak time rebate. Fortunately, the new billing system the Company is planning to deploy would be able to process a peak time rebate program with some minor changes and would be in service on or around 2025. PacifiCorp did assess the potential costs and benefits of peak time rebates in the CPA to inform future determinations and considerations for implementation of peak time rebates.

Order No. 22-178, p. 16-17; Appx B p. 3	Require PacifiCorp to meet with developer intervenors, upon request, to determine a subset of the confidential data supporting the 2023 IRP that does not include commercially sensitive information that can be provided. The subset would not necessarily need to include all confidential data that is not commercially sensitive. Require PacifiCorp to seek to balance developer intervenors' need for information as IRP stakeholders with PacifiCorp's need to protect commercially sensitive information and keep the data management workload to a reasonable level.	PacifiCorp met twice with Commission Staff and associations that represent developers and developer stakeholders that participated in the Company's 2021 IRP proceeding, docket LC 77. The first meeting occurred on November 8, 2022 and a follow up meeting was held on March 20, 2023. As a result of these meetings, PacifiCorp restructured its workpaper reporting format that will allow a greater amount of information to be public. It will also designate commercially sensitive information as highly confidential; thus, ensuring developers will have access to all confidential information, not just a subset.
Order No. 22-178, p. 17	We direct PacifiCorp to hold at least one workshop on equity and justice issues related to the generation transition in its 2023 IRP, and we will ask members of our staff with expertise on these issues to participate. We recognize PacifiCorp's relationship to employees and to the communities where its resources are located and encourage the company to explain how consideration of both factor into planning processes.	PacifiCorp held a "Generation Transition Equity and Justice Workshop" on September 2, 2022. Topics included community action, promotion and organization of resources, employee transition plan and transition program, and current actions. The company has also held 14 CBIAG meetings since October 27, 2022.
Order No. 22-178, p. 18; Appx B p. 1	PacifiCorp to take steps to provide complete and accurate information in the 2023 IRP that reflects accurate IRP modeling assumptions. We adopt this recommendation, though we note that we believe PacifiCorp has already been attempting to comply with this principle.	PacifiCorp has aligned itself with this expectation by providing timely and comprehensive modeling outcomes, which have been included in the 2023 IRP and the preferred portfolio respectively.

Order No. 22-178, p. 18	Require PacifiCorp's 2023 IRP storage costs in the Supply Side Table to be in line with the most recent National Renewal Energy Laboratory Annual Technology Baseline report and most recent RFP Final Shortlist. Our understanding is that Staff's recommendation reflects a preference from stakeholders for publicly available sources, but that Staff also acknowledges the relevance of the market information obtainable from the most recent RFP. We thus adopt Staff's recommendation to the extent that it requires the use of publicly available data as well as proprietary sources, but with the understanding that discrepancies from the publicly available data be explained.	PacifiCorp presented on this topic at the September 1, Public Input Meeting.
Order No. 22-178, p. 18; Appx B p. 1	PacifiCorp to provide a map of resources in the IRP Executive Summary, which PacifiCorp agrees to do.	This requirement is met by the preferred portfolio map provided in Appendix I (Capacity Expansion Results).
Order No. 22-178, p. 18-19; Appx B p. 2	Require PacifiCorp to explain the reliability limitations of the LT capacity expansion model and how the IRP team selected the reliability resources of change. PacifiCorp made a strong effort at explanation in this IRP, but that the company should seek to understand questions that remain and mature its narrative discussion accordingly.	The LT model simultaneously evaluates the entire 20 year IRP horizon and all possible resource additions and retirements. With PacifiCorp's system and resource options, this is a lot of possibilities and the model cannot evaluate every hour, let alone maintain the chronological links necessary to consider all likely combinations of load, wind, and solar while enforcing energy storage duration limits, emissions constraints, and thermal unit cycling restrictions. As a result more granular analysis within the ST model is necessary to identify the extent that reliability, environmental compliance, and economics are addressed. Discussion of reliability resources follows below.

Order No. 22-178, p. 19; Appx B p. 2	Require PacifiCorp to include with the 2023 IRP data discs: A list of the resources that were considered as reliability resources; A list of the reliability resources that were selected in each portfolio, sensitivity, and variant; A clearly marked set of hourly reliability (ENS) data that the Company used to identify the type and size of reliability resources to add to each portfolio, sensitivity, variant; and Any metric the Company used to select reliability resources in each portfolio, sensitivity and variant	All resources were open to consideration as reliability resources for selection based on their value to the system. Workpapers will be provided for each case indicating portfolio changes and for each case indicating hourly unserved energy and reserve shortfalls. These workpapers identify the specific hours in which shortfalls occurred within each year. From the hourly shortfall data, the Company identified the largest consecutive blocks of shortfalls, including the month and hours of the day in which they occurred. The company then reviewed resource costs and benefits reported by Plexos specific to the case in question to determine which types of resources would be most economic to cover the identified need.
Order No. 22-178, p. 19; Appx B p. 2	Before the 2023 IRP, include climate-change risk and adaptation as a topic of a public-input meeting to share and discuss approaches to modeling climate risk in the IRP including: proposed changes to how weather and extreme events are considered; proposed changes for the consideration of climate-related risks on supply side resources, transmission, and loads; and a discussion on how the Company proposes to include climate change impacts as part of the status quo. We adopt this recommendation and note that we appreciate PacifiCorp's thorough responses on this important issue.	PacifiCorp engaged stakeholders on climate change at several public meetings, including: May 12, 2022 September 1-2, 2022 October 13, 2022 A primary function of these discussions was to discuss the incorporation of climate change as a base assumption in the 2023 IRP. In addition a "no climate change" study (W-11 Climate Change Counterfactual) is provided in the 2023 IRP.
Order No. 22-178, p. 20; Appx B p. 2	Change PacifiCorp's Environmental, Transmission, and DSM Updates from a twice-annual report to an annual report.	This change has been adopted.

Order No. 22-178, Appx B p. 1	In the 2023 IRP, PacifiCorp should provide a metric calculated in its capacity expansion model that provides stakeholders with an estimate of the relative value of each coal unit to the system.	This value is calculated in each study for every resource which is available for selection. Each resource's annual value is calculated, as well as an aggregate value over the period of the study.
Order No. 22-178,Appx B p. 1	The 2023 IRP data discs should provide graphs of the average fixed and variable costs of operating each coal unit over the planning timeframe. This should include fuel cost and run rate capital, but exclude depreciation expense.	PacifiCorp will provide appropriate reference materials on the data disc.
Order No. 22-178,Appx B p. 1	As a part of the 2023 IRP development process, PacifiCorp should fully assess the potential for gas conversion; use of hydrogen, biofuel, or other lower-carbon fuels; or alternate coal stockpile or supply methods for Jim Bridger 3 and 4. A report should be included with the 2023 IRP.	PacifiCorp presented its assessment of alternative fuels at the 2023 IRP June 9-10 public input meeting. *"LC 82 (PAC 2023 IRP) – Special Public Meeting – Waivers for extension to file the CEP and Long-Term Fuel Plan."*
Order No. 22-178,Appx B p. 1	If technically feasible, PacifiCorp should report on the costs and emissions (CO2 and NOX) of green hydrogen combustion at the converted Bridger unit.	PacifiCorp continues to assess the viability of green hydrogen, as well as the ability for existing infrastructure to accommodate the chemical properties of this fuel type. The Company's existing generation equipment is not well suited to green hydrogen combustion because exposure to high-temperature hydrogen results in degradation of many critical alloy components, particularly within steam turbines. Conversion of combustion turbines to hydrogen fueling is more promising, because the hot gas path is more contained, with fewer components at risk, but is not yet commercially available for the large turbines in PacifiCorp's fleet. Conversion of combustion turbines could potentially include combined cycle combustion turbines as the associated steam turbine is not directly exposed to hydrogen combustion.

Order No. 22-178,Appx B p. 1	The 2023 IRP should more thoroughly investigate the potential to install a new turbine designed to run on 100 percent green hydrogen at the sites of one or more retiring coal plants.	PacifiCorp continues to assess the viability of green hydrogen, as well as the ability for existing infrastructure to accommodate the chemical properties of this fuel type. PacifiCorp's modeling in the 2023 IRP allows for non-emitting peaking units at current coal plant sites and in other locations. These peaking resources were assumed to be fueled using 100 percent green hydrogen, supplied via pipeline due the high cost of onsite storage, but a wide variety of non-emitting fuels and generation technologies are currently under development.
Order No. 22-178,Appx B p. 1	In the 2023 IRP, variable O&M costs should be modeled accurately as variable with generation, and not approximated as part of fixed O&M costs as they have been in the 2021 IRP.	This enhancement has been incorporated for the 2023 IRP.
Order No. 22-178, Appx B p. 2	In future IRPs or during future RFP processes, potential RFP bidders should be given access to a 12x24 Loss of Load Probability matrix for one out of every five years in the IRP planning timeframe.	Following the completion of the 2021 IRP and in advance of bid submissions in the 2022 All-Source RFP, PacifiCorp prepared the requested information and provided it to stakeholders in its January 25, 2022 filing in docket UM 2011. Following the completion of the 2023 IRP, PacifiCorp will develop comparable information for use in future RFP processes.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
Utah		
DOCKET NO. 90-2035-01 p. 33-37	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The Company will include in its forecasts all on-system loads and those off-system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	PacifiCorp's load forecast is developed for each jurisdiction and by customer class. Further, this forecast includes off-system wholesale customers for which the Company has a contractual obligation to fulfill. To plan for non-firm off-system customer impacts returning to PacifiCorp's system, 1-year and 3-year option direct access customers in Oregon are incorporated into the forecast assuming they will return once their opt-out period expires.
DOCKET NO. 90-2035-01 p. 33-37	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	PacifiCorp has evaluated these market conditions to inform a least-cost, least-risk preferred portfolio outcome. Changes to consumer behavior are also outlined under the suite of existing demand-side management, energy efficiency and load forecast projections at the disposal of the Company.
DOCKET NO. 90-2035-01 p. 33-37	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	PacifiCorp has attempted to include a wide range of potential resource options within its supply-side table, and has included reasonable cost estimates for all resource types. Where costs and operating characteristics are similar, as with different lithium-ion chemistries, the IRP does not attempt to differentiate – no particular technology is correct, and differences in performance are expected to be well within the normal range of offers from bidders. Even non-emitting peaking and nuclear resources are ultimately proxies for their particular combinations of costs, operating characteristics, and risks. Many types of risks are expected to evolve over the next few planning cycles both risks associated with these new technologies, and those associated with emitting technologies.

DOCKET NO. 90-2035-01 p. 33-37	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp has evaluated all technically feasible and cost-effective energy efficiency, conservation, and load management through the Conservation Potential Assessment to compete with other resources in the IRP modeling.
DOCKET NO. 90-2035-01 p. 33-37	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp has evaluated all known technically feasible generating technologies including: renewable resources, cogeneration, and the construction of thermal resource. The IRP does not represent ownership structures for proxy resources. Any resource could end up being a Build Transfer Agreement (BTA), Power Purchase Agreement (PPA), self-build, or other contract structure.
DOCKET NO. 90-2035-01 p. 33-37	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.	The resource assessments include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, and efficiency of the resource and opportunities for customer participation.
DOCKET NO. 90-2035-01 p. 33-37	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions.	Demand side bids were permitted to participate in the all-source RFP and inputs for assessment was developed so that potential demand side bids could compete with supply side resources. Additionally, demand side resources are evaluated as part of the IRP modeling to evaluate overall competitiveness with other resources.

DOCKET NO. 90-2035-01 p. 33-37	A 20-year planning horizon.	The 2023 IRP covers a 20-year horizon from 2023 through 2042.
DOCKET NO. 90-2035-01 p. 33-37	A two-year action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan.	This requirement is met in Volume I, Chapter 10 (Action Plan).
DOCKET NO. 90-2035-01 p. 33-37	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the Company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	This requirement is met in Volume I, Chapter 10 (Action Plan).
DOCKET NO. 90-2035-01 p. 33-37	Load forecasts integrated with resource options in a manner which rationalizes the choice of resources under a variety of economic circumstances.	Modeling for the 2023 IRP incorporates multiple load forecasts and price-policy scenarios under which resources compete on an optimized basis for the selection of resource options, retirements, unit conversions, transmission options, market purchases and sales, and other elements. See Volume I, Chapters 7, 8 and 9.

DOCKET NO. 90-2035-01 p. 33-37	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.	PacifiCorp presents it alternative path analysis in Volume I, Chapter 10 (Action Plan).
DOCKET NO. 90-2035-01 p. 33-37	An evaluation of the cost-effectiveness of the resource options from a variety of perspectives and society as a whole.	PacifiCorp's 2023 IRP evaluates risk via a risk-adjustment metric based on stochastic modeling results, provides a set of competitive variant portfolios, and includes studies assuming a social cost of greenhouse gas cost-adder as a price-policy scenario.
DOCKET NO. 90-2035-01 p. 33-37	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 2023 IRP evaluates risk via a risk-adjustment metric based on stochastic modeling results, and includes a Business Plan sensitivity. The 2023 IRP will be used to inform the Business Plan.
DOCKET NO. 90-2035-01 p. 33-37	An evaluation of the financial, competitive, reliability, and operational 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. The Company will identify who should bear such risk, the ratepayer or the stockholder.	The 2023 IRP endogenously evaluates the attributes of competing resource options through its input data, which is reflective of the costs, operational characteristics, technology type, location, interconnection availability and other factors. In addition, the RFP non-price scoring process evaluates, in coordination with several independent evaluators representing three states, the project and reliability risks and scores these results accordingly. The assumptions in the Business Plan and 20-year Integrated Resource Plan are ultimately modified and realized through actual generating projects that are either owned or under contract and represent ratepayer risk, not shareholder risk, except to the extent that the commitments or actions of the Company are deemed imprudent in a future ratemaking proceeding. During RFP procurements, the terms of contracts are also reviewed by

		independent evaluators and are available and submitted to regulatory staff upon request or by order or statute. These contracts include performance guarantees to balance the risk between the project owner and the Company on behalf of ratepayers.
DOCKET NO. 90-2035-01 p. 33-37	Considerations permitting flexibility in the planning process so that the Company can take advantage of opportunities and can prevent the premature foreclosure of options.	PacifiCorp assesses the potential value of resources against risk and the expense of time and resources in the development of its supply side resources. The 2023 IRP included discussion of supply side resource, beginning earlier in the public input process than in previous IRPs, and revisited several times. Particular options were considered in expanded discussion topics such as coal options and offshore wind. The 2023 IRP also included natural gas resource options, which had been excluded in the 2021 IRP.
DOCKET NO. 90-2035-01 p. 33-37	An analysis of tradeoffs; for example, between such conditions of service as reliability and the acquisition of lowest cost resources.	The 2023 IRP inherently evaluates trade-offs between reliability and resource cost, as well as operational costs incurred during dispatch as part of the core functionality of optimization modeling. This is the purpose of the optimization. Additional analysis is provided in narrative form where salient trade-offs are indicated in portfolio outcomes. See Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
DOCKET NO. 90-2035-01 p. 33-37	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, in order to show how explicit consideration of them might affect selection of resource options. The Company will attempt to quantify the magnitude of the externalities, for example, in terms of the amount of emissions released and dollar estimates of the costs of such externalities.	Future environmental and safety regulation has an almost unfathomable potential range of outcomes, many of which may be contradictory with other rules or policy goals, as in restrictions on non-emitting resources. What is certain, is that compliance may involve costs dramatically in excess of even the social cost of greenhouse gases price-policy scenario. As an example, coal ash handling and water treatment is only partly related to ongoing operations, but the costs could offset years of possible operational benefits depending on the circumstances. Environmental and safety regulation is not limited to fossil fuel resources, a few very basic examples include: - Very few battery chemistries have significant history in utility-scale operations, and some examples of fire hazards have been identified.

		- Wind turbines present risks related to birds and bats. - Cadmium telluride solar panels include two toxic chemicals, which while significantly less harmful in compound form, do not have well documented long-term effects. The above is not intended to be comprehensive - all technologies have trade-offs and risks though some technologies have more unknown unknowns than others. The largest externality of which the Company is currently aware is the impact of greenhouse gases on the climate. A price-policy scenario with an estimate of the social cost of greenhouse gases is used to quantify that particular externality, and analysis including those costs is presented for the preferred portfolio and selected variant portfolios.
DOCKET NO. 90-2035-01 p. 33-37	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein, and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the Company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgement of an acceptable Integrated Resource Plan. The Company will give an oral presentation of its report to the Commission and all interested public parties. Formal hearings on the acknowledgement of the Integrated Resource Plan might be appropriate but are not required. 7. Acknowledgement of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	PacifiCorp will participate fully in the described process.

Docket No. 21-035-09, UPSC June 2, 2022 Order p. 5-8	PacifiCorp must comply with Guidelines 4(b) and 4(i) by not constraining its model to preclude selection of new natural gas resources	The 2023 IRP included natural gas resource options, which had been excluded in the 2021 IRP.
Docket No. 21-035-09, UPSC June 2, 2022 Order p. 9-18	PacifiCorp will provide information to stakeholders three business days in advance of public meetings	PacifiCorp consistently provided meeting materials to stakeholders via email within the parameters of this requirement. See Volume II, Appendix C (Public Input).

DOCKET NO. 90-2035-01 p. 33-37	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	PacifiCorp is compliant with this standard.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
Washington		
State Rule/Statute Requirement	Incorporate the social cost of greenhouse gases (SCGHG) as a cost adder, as required by RCW 19.280.030(3), and provide a narrative illustrating step-by-step how the SCGHG cost adder is applied throughout its modeling logic. The SCGHG impact on the Company's modeling and portfolio analyses should be addressed in numerous variables, including PacifiCorp's imports and contracts and forward price curves.	PacifiCorp is compliant with this statute and has provided a narrative framework outlining carbon price policy scenario assumptions and nominal electric and natural gas price inputs, which were discussed at the February 23, 2023 Public Input meeting.
State Rule/Statute Requirement	Integrate the demand forecasts and resource evaluations into a long-range IRP solution describing the mix of resources that meet current and projected resource needs, abiding by a variety of constraints pursuant to statute and per Commission rule. WAC 480-100-620(11)	The Plexos models were used to evaluate resource on a comparable basis following the requirements in statute and appropriate to this filing's status as a Two-Year Progress Report. See Chapter 8 and Appendix O.
State Rule/Statute Requirement	Include an assessment of battery and pumped storage for integrating renewable resources. The assessment may consider ancillary services at the appropriate granularity required to model such storage resources. WAC 480-100-620(5)	The 2021 IRP Two-Year Progress Report incorporates multiple storage options including lithium-ion, flow and iron-air batteries, and pumped hydro storage. Modeling was conducted at appropriate granularity in the Plexos LT, MT and ST models. See Volume I, Chapters 7 and 8.
State Rule/Statute Requirement	A future climate change scenario that meets the requirements of WAC 480-100-620(10)(b), which is "At least one scenario must be a future climate change scenario. This scenario should incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes	PacifiCorp's base case includes future climate impacts on the load forecast, energy efficiency potential, and the hydro generation forecast. The base load forecast for the 2023 IRP is based on a Bureau of Reclamation median projection of climate impacts through time on heating and cooling degree days, resulting in increasing divergence from the 20-year normal weather further in the IRP planning horizon. The hydro forecast similarly relies on projected seasonal changes in streamflows in response to

	resulting from climate change."	climate impacts that evolve across the IRP planning horizon. A scenario using the 20-year normal weather forecast for load and hydro was prepared for comparison purposes.
State Rule/Statute Requirement	Identify an appropriate resource adequacy requirement (i.e., loss of load probability) and complete the assessment, as required by WAC 480-100-620(8)	This item is not required for a Two-Year Progress Report and is not explicitly addressed in terms of avoided cost in this filing. However, the Progress Report includes expanded reporting of reliability assessment including identifying deficiencies and the resolution of deficiencies based on model outcomes. The Plexos modeling process and the ENS metric indicates that reliability has been achieved.
State Rule/Statute Requirement	Provide resource assumptions and market forecasts used in the utility's schedule of estimated avoided costs required in WAC 480-106-040, including but not limited to: -Cost Assumptions -Production Estimates -Peak capacity contribution estimates and annual capacity factor estimates	This item is not required for a Two-Year Progress Report and is not explicitly addressed in terms of avoided cost in this filing. However, resource assumptions, capacity factors and price forecasts are included in workpapers. PacifiCorp would note that its 2023 IRP uses forward market prices from September 2022, which is the same vintage as PacifiCorp's November 1, 2022 avoided cost filing in docket number 220804
State Rule/Statute Requirement	Compare and evaluate all identified resources and potential changes to existing resources for achieving the clean energy transformation standards in WAC 480-100-610 at the lowest reasonable cost, including a narrative of the decisions it has made. WAC 480-100-620(7) and (11)	The 2021 IRP Two-Year Progress Report compares all resource options in its optimized evaluation, and provides narratives of comparative analysis of outcomes in Volume I, Chapter 9, and details regarding resource attributes in Volume I, Chapter 7.
	Address WAC 480-100-620(2), The IRP must include a range of forecasts of projected customer demand that reflect the effect of economic forces on the consumption of electricity and address changes in the number, type, and efficiency of end uses of electricity. 1.) alternative load forecast scenarios, including climate change impacts 2.) Optimistic and Pessimistic assumptions in the low and high growth models and how these alternative forecasts differ from the base forecast 3.) Electrification adjustments made to the load forecast	PacifiCorp conducts a variety of load forecast scenarios. Also, to account for changes in the number, type and efficiency of end-uses, the Company updates its statistically adjusted end-use model used in the load forecast. See Volume II, Appendix A (Load Forecast) for details regarding the alternative load forecast scenarios. Specifically, the Company's base forecast includes expected climate change impacts on loads, while the 20-year normal load forecast scenario provides the load forecast without explicitly accounting for climate change temperatures. Further, the Company does produce both optimistic and pessimistic load forecast scenarios. Please refer to Appendix A (Load Forecast) for details regarding transportation and building electrification adjustments made to the load forecast.
State Rule/Statute Requirement	Address how the IRP update meets with the requirement in RCW 19.280.030(1)(m) regarding electric and zero-emission vehicles. RCW 19.280.030(1)(m) An analysis	PacifiCorp's load forecast accounts for zero-emission vehicles using the methods to determine utility impacts described in the Company's Washington Transportation Electrification Plan. PacifiCorp develops multiple electric vehicle adoption futures

	of how the plan accounts for: (I) Modeled load forecast scenarios that consider the anticipated levels of zero emissions vehicle use in a utility's service area, including anticipated levels of zero emissions vehicle use in the utility's service area provided in RCW 47.01.520, if feasible; (ii) Analysis, research, findings, recommendations, actions, and any other relevant information found in the electrification of transportation plans submitted under RCW 35.92.450, 54.16.430, and 80.28.365; and (iii) Assumed use case forecasts and the associated energy impacts. Electric utilities may, but are not required to, use the forecasts generated by the mapping and forecasting tool created in RCW 47.01.520. This subsection (1)(m)(iii) applies only to plans due to be filed after September 1, 2023.	for consideration. PacifiCorp updated its zero-emission vehicle forecast in September of 2022 account for impacts from the inflation reduction act and recently adopted ZEV standards.
State Rule/Statute Requirement	Demonstrate a wider incorporation of non-energy impacts (NEIs) in addition to those applied during conservation potential assessment (CPA) development. WAC 480-100-620(11)(g)	PacifiCorp applied measure specific NEI results from a DNV NEI study in 2021 which developed a comprehensive assessment of NEIs. In response to stakeholder comments about NEI valuation, PacifiCorp revisited assumptions and presented results at the April 28, 2022, DSM advisory group meeting. Upon finalization of results, PacifiCorp mapped measure specific NEI's to measures in the conservation potential assessment. This represents a broader application of NEIs compared to the prior study which used a proxy value adder to represent NEI valuation. Additionally, for demand response, a literature review was conducted to determine if there were any program specific NEIs. Since no quantitative values were found in the literature review, PacifiCorp chose to include a 10% adder to approximate NEI impacts for demand response. In the prior study, no NEI's were included for demand response.
State Rule/Statute Requirement	Attribute NEIs considered, indicating whether nonenergy costs and benefits accrue to the utility, customers, participants, vulnerable populations, highly impacted communities, and/or the general public. WAC 480-100-620(13)	The file labeled "2023 CPA - Appendix E - WA Non-Energy Impact Mapping", as part of the CPA supplemental materials posted on the website, maps the accrual of NEIs to various groups consistent with WAC 480-100-620(13).
State Rule/Statute Requirement	Summarize (WAC 480-100-620(17)): -Public Comments received during the 2023 IRP development (rather than providing a download of stakeholder feedback forms the company has	PacifiCorp has maintained compliance with this requirement by publishing all stakeholder comments received and associated responses in a centralized location externally. The narrative framework for each stakeholder form received is also outlined in greater detail in Appendix C of the 2023 IRP.

	received to date -PacifiCorp corresponding responses to public comment -Whether and how the final plan addresses and incorporates comments received	
State Rule/Statute Requirement	Distributed energy resource (DER) potential assessments (WAC 480-100-620(3)(b)) Sub-section (iii) (energy assistance potential assessment)--The IRP must include distributed energy programs and mechanisms identified pursuant to RCW 19.405.120, which pertains to energy assistance and progress toward meeting energy assistance need. Sub-section (iv) (other DER potential assessments) – The IRP must assess other DERs that may be installed by the utility or the utility's customers including, but not limited to, energy storage, electric vehicles, and photovoltaics. Any such assessment must include the effect of DERs on the utility's load and operations. DER potential assessment(s) must go beyond the utility's legacy approach showing DERs as simply a load forecast decrement	The Company assesses various levels of DER through a variety of methods. PacifiCorp evaluates private generation by considering varying levels of technology costs and electricity rate assumptions, which are considered within the Company's high and low private generation load forecast sensitivities. With regard to the energy assistance potential assessment, PacifiCorp evaluates energy efficiency potential by income level so as to inform how energy efficiency resources can meet energy assistance need. The 2023 IRP also assesses other DERs such as energy storage, which is considered within the Company's private generation study and the CPA as a demand response resource for acquisition is subsequently incorporated into PacifiCorp's load forecast and IRP modeling. Further, utility scale battery storage is considered as a resource option within the context of portfolio analysis. The Company incorporates electric vehicle demand within the load forecast along with the control of electric vehicle load as a demand response resource in the IRP model.
State Rule/Statute Requirement	For the duration of the IRP public interest meetings (PIMs) informing PacifiCorp's 2023 IRP progress report cycle, circulate completed presentation materials at least three business days prior to each meeting. WAC 480-100-630(2).	PacifiCorp consistently provided meeting materials to stakeholders via email within the parameters of this requirement.
Order Requirement	Provide all data input files to the Commission in native format with appropriate context (e.g., assumptions made by the Company) as appendices or attachments to the final filing or via accompanying data disk(s). Dockets UE-191023 and UE-190698, General Order R-601 at 60-61, ¶ 173 and 178	PacifiCorp carefully manages its workpaper filing to adhere to this requirement within the limits of technology. Context is provided by the accompanying listing of file names with a description of the file's content or purpose. This information is provided on the data disk.
Order Requirement	Include complete data sets informing the Company's preferred portfolio. Dockets UE-191023 and UE-190698, General Order R-601 at 60-61, ¶ 173 and 178	The 2023 IRP data disc includes complete workpapers for each portfolio including the preferred portfolio.

Order Requirement	During CPA development, demonstrate progress towards identifying, researching, and properly valuing NEIs. Docket UE-210830, Order 01, Attachment A, condition 11a	PacifiCorp discussed NEI research with the DSM advisory group on October 12, 2021, February 28, 2022 and April 28, 2022 and with the equity advisory group on June 16, 2022. These discussions sought feedback on NEI valuation, research and application. The 2023 CPA included measure specific NEIs for energy efficiency and proxies for demand response that were more substantive and comprehensive compared to what was used in the 2021 CPA.
Rule Requirement	At least every two years after the utility files its IRP, beginning January 1, 2023, the utility must file a two-year progress report. (a) In this report, the utility must update its: (i) Load forecast; (ii) Demand-side resource assessment, including a new conservation potential assessment; (iii) Resource costs; and (iv) The portfolio analysis and preferred portfolio. (b) The progress report must include other updates that are necessary due to changing state or federal requirements, or significant changes to economic or market forces. (c) The progress report must also update for any elements found in the utility's current clean energy implementation plan, as described in WAC 480-100-640.	The 2023 IRP incorporates an updated load forecast, updated Demand-side management potential assessment, updated resource cost assumptions and portfolio analysis including the preferred portfolio. Please refer to Appendix O (Washington 2021 IRP Two-year Progress Report Additional Elements), for additional detail regarding updates for elements of the Clean Energy Implementation Plan.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
Wyoming		
The following requirements correspond to the WPSC's Order issued in the 2019 IRP investigation, the latest available for the 2023 IRP.		
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include a Reference Case based on the 2017 IRP Updated Preferred Portfolio, incorporating updated assumptions, such as load and market prices and any known changes to system resources and using environmental investments or costs only required by current law. For example, the reference case will not include an estimate or	PacifiCorp has complied with this requirement. Additional information on the specified reference case can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

	assumed price or cost for carbon emissions absent an existing legal requirement.	
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Conduct a more extensive analysis of the impact of alternative price-policy scenarios on the resource plan.	The impact of price-policy scenarios on the resource plan is summarized in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Conduct a sensitivity analysis on top performing portfolio cases and the reference case.	PacifiCorp has complied with this requirement. Additional information on sensitivity analyses can be found within Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Demonstrate rate impacts over the planning period between preferred portfolio and the reference case.	The 2023 IRP includes reference case P02-JB3-4 EOL, which continues Wyoming coal through end-of-life until necessity of gas conversion or other treatment driven by major by environmental requirements.
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Investigate alternative methodologies to integrate different reliability analyses including regional analysis of resource adequacy; analysis of power flow issues caused by retiring coal units; study of potential weather-related outages on intermittent generation; and an analysis of wildfire risk.	PacifiCorp has introduced a new chapter into this IRP – Volume I, Chapter 5 (Reliability and Resiliency) – which includes regional analyses of resource adequacy, a discussion of power flow issues caused by baseload resource retirements and how PacifiCorp Transmission is planning for those retirements, an assessment of weather-related outages, and a discussion of wildfire risk and mitigation.
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include additional analysis on operational experience, if any, with battery acquisition and operations and include a review of capabilities learned from other utilities.	PacifiCorp has included a description of procurement and operational experience with battery acquisition and operations as part of Volume I, Chapter 7 (Resource Options).
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include an analysis that demonstrates how the Company will maximize the use of dispatchable and reliable low-carbon electricity pursuant to HB200.	PacifiCorp has included Carbon Capture Utilization and Sequestration analysis within the portfolio modeling process. Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Incorporate an analysis of any agreed upon change to the MSP and to the extent there are outstanding material disagreements regarding cost allocation at the time of filing, quantify those risks and potential impact to Wyoming ratepayers.	PacifiCorp has included a discussion of the current status of the MSP within Volume I, Chapter 3 (Planning Environment). As there are no agreed-upon changes or outstanding material disagreements, PacifiCorp did not quantify potential impacts. To the extent that there are changes and/or material disagreements in future IRP cycles, the company will include the required quantified risk.
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include a broader analysis of all generation types including nuclear and natural gas.	PacifiCorp has expanded the generation types included in the supply-side table as part of the 2023 IRP. Advanced nuclear and natural gas resources have both been included in the supply-side table and analyzed in the 2023 IRP. Additional newly

		evaluated resources include offshore wind and long-term storage options.
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include a narrative discussing impacts and regulatory framework for renewable generation.	PacifiCorp has added this narrative analysis to the Planning Environment discussion in Volume I, Chapter 3 (Planning Environment).
Order, Docket No. 90000-144-XI-19 (Record No. 15280)	Include an acknowledgement that each of these requirements are addressed in the 2023 IRP to ensure compliance.	PacifiCorp acknowledges these requirements and has addressed each within the 2023 IRP.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2023 IRP
California		
D.18-02-018 D.22-02-004 Public Utilities Code §§ 399.13(a)(7), 454.5, 454.52	Addressing Disadvantaged Communities Provide supplemental information about disadvantaged communities, including "a demonstration of how disadvantaged communities were considered." (D.18-02-018, p. 135.) "PacifiCorp is required to supplement its multi-state IRP with … specific information on … a separate demonstration that satisfies the requirements for disadvantaged communities." (D.22-02-004, p. 22.) "At a minimum, all LSEs shall provide the following information in their IRPs: i. A description of which disadvantaged communities, if any, it serves (LSEs will be expected to make the determination of what is considered "disadvantaged" every two years); ii. What current and planned LSE activities/programs, if any, impact disadvantaged communities; and iii. A qualitative description of the demographics of the customers it serves and how it is currently addressing or plans to comply with the requirement to minimize air pollutants." (D.18-02-018, p. 68.)	PacifiCorp serves fewer than 50,000 customers in mostly rural northern California, with a significant number of customers on energy assistance programs. PacifiCorp's California customers are geographically-dispersed, with approximately four customers per square mile. [3]. PacifiCorp is committed to affordability to protect disadvantaged communities. In PacifiCorp's most current general rate case, which is currently pending at the California Public Utilities Commission, the company has requested recovery of costs associated with the addition of investments in renewable generation resources. Those resources reduce overall emissions and provide zero-fuel cost energy and production tax credits that benefit our customers. PacifiCorp also proposed an increase to its California Alternative Rates for Energy discount from 20 percent to 25 percent, new time varying rate options, and paperless bill credit, among other changes, to support customers during increased costs for wholesale energy and wildfire mitigation. In 2023, PacifiCorp plans to transition its Home Energy Savings residential energy efficiency program from a resource acquisition program to an equity program targeting Hard-to-Reach and Tribal csutomers. In addition, PacifiCorp filed an advice filing requesting approval to offer Home Energy Reports as an equity program targeting only Hard-to-Reach and Tribal customers.

[3] SB 535 Disadvantaged Communities | OEHHA (ca.gov)

	If we wish to provide additional information, we can address how PacifiCorp is: • strengthening "the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities." (D.18-02-018, p. 66; Pub. Util. Code § 454.52.) • minimizing "localized air pollutants and other greenhouse gas emissions, with early priority on disadvantaged communities." (D.18-02-018, p. 66; Pub. Util. Code § 454.52.) • giving "preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria pollutants, and greenhouse gases." (D.18-02-018, p. 67; Pub. Util. Code § 399.13(a)(7).) In soliciting bids for new gas-fired generating units, PacifiCorp should "actively seek bids for resources that are not gas-fired generating units located in communities that suffer from cumulative pollution burdens, including, but no [sic] limited to, high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases." (D.18-02-018, p. 67; Pub. Util. Code § 454.5(b)(9)(D).)	PacifiCorp IRP identifies increased investment in non-emitting resources to service all of its customers. Further, PacifiCorp does not own or operate any thermal generation in California that would negatively impact communities in the California service area.

D.19-04-040 D.22-02-004 ALJ Ruling Finalizing Load Forecasts and Greenhouse Gas Emissions Benchmarks for 2022 Integrated Resource Plan Filings	GHG Emissions Accounting "PacifiCorp should consult with Commission staff and describe an alternative [to the CNS/CSP Calculator] methodology that addresses its share of the 2030 GHG emissions reduction responsibility." (D.19-04-040, p. 74.) "PacifiCorp is required to supplement its multi-state IRP with … specific information on … another (non-CSP calculator) method to fulfill requirements that would otherwise have required the CSP tool and justification for the choice." (D.22-02-004, p. 22.) PacifiCorp's GHG benchmarks are available here: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/2022-final-ghg-emission-benchmarks-for-lses_public.xlsx	PacifiCorp met with CPUC staff in 2020 and discussed its alternative methodology to address GHG benchmarks. PacifiCorp's IRP supplement will include the results of the emissions forecast in California relative to GHG Benchmark.

Table B.3 – Oregon Public Utility Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
Guideline 1. Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis: All known resources for meeting the utility's load should be considered, including supply- side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PacifiCorp considered a wide range of resources including renewables, demand-side management, energy storage, power purchases, thermal resources, and transmission. Volume I, Chapter 4 (Transmission Planning), Chapter 7 (Resource Options), and Chapter 8 (Modeling and Portfolio Evaluation) document how PacifiCorp developed these resources and modeled them in its portfolio analysis. All these resources were established as resource options in the company's capacity expansion optimization model, Plexos, and selected by the model based on load requirements, relative economics, resource size, availability dates, and other factors.
1.a.2	All resources must be evaluated on a consistent and comparable basis: Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	All portfolios developed with Plexos were subjected to Monte Carlo production cost simulation. These portfolios contained a variety of resource types with different fuel types (coal, gas, biomass, nuclear fuel, "no fuel" renewables), lead-times (ranging from front office transactions to nuclear plants), in-service dates, operational lives, and locations. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation), Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix I (Capacity Expansion Results) and Appendix J (Stochastic Simulation Results).
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company developed generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used the Applied Energy Group's supply curve data developed for this IRP for representation of DSM resources. The study was based on a consistently applied methodology for determining technical, market, and achievable DSM potentials. All portfolio resources were evaluated using the same sets of price and load forecast inputs. These inputs are documented in Volume I, Chapter 6 (Load and Resource Balance), Chapter 7 (Resource Options), and Chapter 8 (Modeling and Portfolio Evaluation) as well as Volume II, Appendix D (Demand-Side Management).
1.a.4	All resources must be evaluated on a consistent and comparable basis: The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PacifiCorp applied its nominal after-tax WACC of 6.77 percent to discount all cost streams.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	Each of the sources of risk identified in this guideline is treated as a stochastic variable in PacifiCorp's production cost simulation apart from CO2 emission compliance costs, which are treated as a scenario risk and evaluated as part of a CO2 price assumption and a no CO2, a high CO2, and a social cost of carbon price-policy scenario for specific studies. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	Resource risk mitigation is discussed in Volume I, Chapter 10 (Action Plan). Regulatory and financial risks associated with resource and transmission investments are highlighted in several areas in the IRP document, including Volume I, Chapter 3 (Planning Environment), Chapter 4 (Transmission), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results).
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio").	PacifiCorp evaluated cost/risk tradeoffs for each of the portfolios considered. See Volume I, Chapter 9 (Modeling and Portfolio Selection Results), Chapter 10 (Action Plan), and Volume II, Appendix I (Capacity Expansion Results) and Appendix H (Stochastic Parameters) for the company's portfolio cost/risk analysis and determination of the preferred portfolio.
1.c.1	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PacifiCorp used a 20-year study period (2023-2042) for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short- lived resources such as gas supply and short-term power purchases.	Volume I, Chapter 8 (Modeling and Portfolio Evaluation) provides a description of the PVRR methodology.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
1.c.3.1	To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	PacifiCorp uses the standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates several measures, including stochastic upper-tail mean PVRR and the 95th percentile stochastic production cost PVRR.
1.c.3.2	To address risk, the plan should include, at a minimum: 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	A discussion on hedging is provided in Volume I, Chapter 10 (Action Plan).
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) summarizes the results of PacifiCorp's cost/risk tradeoff analysis and describes what criteria the company used to determine the best cost/risk portfolios and the preferred portfolio.
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and potential state and federal energy/pollutant emission policies in portfolio modeling. Volume I, Chapter 7 (Modeling and Portfolio Evaluation) describes the decision process used to derive portfolios, which includes consideration of state and federal resource policies and regulations that are summarized in Volume I, Chapter 3 (Planning Environment). Volume I, Chapter 9 (Modeling and Portfolio Selection Results) provides the results. Volume I, Chapter 10 (Action Plan) presents an acquisition path analysis that describes resource strategies based on regulatory trigger events.
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Oregon PUC for resolution.	PacifiCorp fully complies with this requirement. Volume II, Appendix C (Public Input) provides an overview of the public input process, all public-input meetings held for the 2023 IRP, and summarizes public input received throughout the 2023 IRP cycle. PacifiCorp also made use of a Stakeholder Feedback Form for stakeholders to provide comments and offer suggestions. Stakeholder Feedback Forms along with responses and the public-input meeting presentations are available on PacifiCorp's webpage at: www.pacificorp.com/energy/integrated-resource- p lan.html
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Oregon PUC.	2023 IRP Volumes I and II provide non-confidential information used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email and in response to Stakeholder Feedback Forms. Data discs will be available with public data. Additionally, data discs with confidential data will be provided to appropriate parties through use of a general protective order.

2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Oregon PUC.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public input meetings and solicited/and received feedback at various times when developing the 2023 IRP. The materials shared with stakeholders at these meetings, outlined in Volume II, Appendix C (Public Input), is consistent with materials presented in Volumes I and II of the 2023 IRP report. PacifiCorp requested and responded to comments from stakeholders when establishing modeling assumptions and throughout its portfolio-development process and sensitivity definitions.
Guideline 3: Plan Filing, Review, and Updates		
3.a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Oregon PUC.	The 2023 IRP complies with this requirement.
3.b	The utility must present the results of its filed plan to the Oregon PUC at a public meeting prior to the deadline for written public comment.	This activity will be conducted following the filing of this IRP.
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	This activity will be conducted following the filing of this IRP.
3.d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the IRP before issuing an acknowledgment order.	This activity will be conducted following the filing of this IRP.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable.
3.f	(a) 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. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Oregon PUC, unless the utility is within six months of filing its next IRP. The utility must summarize the update at an Oregon PUC public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	Not applicable to this filing; this activity will be conducted following the filing of this IRP.
3.g	Unless the utility requests acknowledgment of changes in proposed actions, the annual update is an informational filing that: • Describes what actions the utility has taken to implement the plan; • 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 • Justifies any deviations from the acknowledged action plan.	Not applicable to this filing; this activity will be conducted following the filing of this IRP.
Guideline 4. Plan Components: At a minimum, the plan must include the following elements		
No.	**Requirement**	**How the Guideline is Addressed in the 2023 IRP**
4.a	An explanation of how the utility met each of the substantive and procedural requirements.	The intent of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	PacifiCorp developed low, high, and extreme peak temperature (one-in-twenty probability) load growth forecasts for scenario analysis using the Plexos model. Stochastic variability of loads was also captured in the risk analysis. See Volume I, Chapters 6 (Load and Resource Balance) and Chapter 8 (Modeling and Portfolio Evaluation), and Volume II, Appendix A (Load Forecast Detail) for load forecast information.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested.	See Chapter 6 (Load and Resource Balance) for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies. Future transmission additions used in analyzing portfolios are summarized in Volume I, Chapter 4 (Transmission) and Chapter 8 (Modeling and Portfolio Evaluation).
4.d	For gas utilities only.	Not applicable.
4.e	Identification and estimated costs of all supply-side and demand side resource options, considering anticipated advances in technology.	Volume I, Chapter 7 (Resource Options) identifies the resources included in this IRP and provides their detailed cost and performance attributes. Additional information on energy efficiency resource characteristics is available in Volume II, Appendix D (Demand-Side Management Resources) referencing additional information on PacifiCorp's IRP website.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	In addition to incorporating a planning reserve margin for all portfolios evaluated, as supported by an updated Stochastic Loss of Load Study in Volume II, Appendix J (Stochastic Simulation Results), the company used several measures to evaluate relative portfolio supply reliability. These measures (Energy Not Served and Loss of Load Probability) are described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered.	Volume I, Chapter 8 (Modeling and Portfolio Evaluation) describes the key assumptions and alternative scenarios used in this IRP. Volume II, Appendix I (Capacity Expansion Results) includes summaries of assumptions used for each case definition analyzed in the 2023 IRP.
4.h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system.	This IRP documents the development and results of portfolios designed to determine resource selection under a variety of input assumptions in Volume I, Chapters 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) incorporates the stochastic portfolio modeling results as described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), and describes portfolio attributes that explain relative differences in cost and risk performance.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) provides tables and charts with performance measure results, including rank ordering.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	See responses to 1.b.1 and 1.b.2 above.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is designed to avoid inconsistencies with state and federal energy policies therefore none are currently identified.
4.n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Volume I, Chapter 10 (Action Plan) presents the 2023 IRP action plan.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	PacifiCorp evaluated four sensitivities on Energy Gateway transmission project configurations on a consistent and comparable basis with respect to other resources. Where new resources would require additional transmission facilities the associated costs were factored into the analysis. Fuel transportation costs were factored into resource costs. In addition to endogenous resource and transmission selects, the 2023 IRP modeled seven variants' cases to evaluate Energy Gateway and its components, B2H, and Cluster 1 and 2 transmission. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation), and specifically Table 8.11 – Preferred Portfolio Variants.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	PacifiCorp's conservation potential study is available on the company's webpage, and the most recent results from the conservation potential assessment have been incorporated into the IRP modeling process.
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	PacifiCorp's energy efficiency supply curves incorporate Oregon resource potential. Oregon potential estimates were provided by the Energy Trust of Oregon. See the demand-side resource section in Volume I, Chapter 7 (Resource Options), the results in Volume I, Chapter 9 (Modeling and Portfolio Selection Results), the targeted amounts in Volume I, Chapter 10 (Action Plan) and the implementation steps outlined in Volume II, Appendix D (DSM Resources
6.c	To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should: 1. Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and 2. Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	See the response for 6.b above.
Guideline 7: Demand Response		
7	Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	PacifiCorp evaluated demand response resources (DSM) on a consistent basis with other resources.

Guideline 8: Environmental Costs		
No.	**Requirement**	**How the Guideline is Addressed in the 2023 IRP**
8.a	Base case and other compliance scenarios: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as an allowance for credit trading as a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	See Volume I, Chapter 8 (Modeling and Portfolio Evaluation). In the 2023 IRP, PacifiCorp's base assumption includes a proxy price on CO_2 starting in 2025 within the medium gas/medium ("MM") CO_2 price-policy scenario for evaluation of all portfolios. In addition PacifiCorp modeled a high gas/high CO_2 ("HH") and a Social Cost of Greenhouse Gas price-policy scenario ("SC") for the preferred portfolio and relevant variants.
8.b	Testing alternative portfolios against the compliance scenarios: The utility should estimate, under each of the compliance scenarios, the present value revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	Volume II, Appendix J (Stochastic Simulation Results) provides the stochastic mean PVRR versus upper tail mean less stochastic mean PVRR scatter plot diagrams that for a broad range of portfolios developed with a range of compliance scenarios as summarized in 8.a above. The company considers end-effects in its use of Real Levelized Revenue Requirement Analysis, as summarized in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and uses a 20-year planning horizon. Early retirement and gas conversion alternatives to coal unit environmental investments were considered in the development of all resource portfolios.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
8.c	Trigger point analysis: The utility should identify at least one CO_2 compliance “turning point” scenario, which, if anticipated now, would lead to, or “trigger” the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio’s expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO2 compliance scenarios. The utility should provide its assessment of whether a CO2 regulatory future that is equally or more stringent that the identified trigger point will be mandated.	See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) for a description of initial portfolio development definitions. Comparative analysis of these case results is included in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
8.d	Oregon compliance portfolio: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those in the preferred and alternative portfolios.	Several portfolios yield system emissions aligned with state goals for reducing greenhouse gas emissions. These cases are summarized in Volume I, Chapter 9 (Modeling and Portfolio Selection Results). PacifiCorp’s Clean Energy Plan will filed by June 1, 2023, incremental to the statewide 2023 IRP preferred portfolio outcomes.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Oregon Docket UE 267 established a long-term opt out option for eligible PacifiCorp customers. Going forward PacifiCorp will cease planning for customers who elect direct-access service on a long-term basis (i.e. five-year opt out customers).
Guideline 10: Multi-state Utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2023 IRP conforms to the multi-state planning approach as stated in Volume I, Chapter 2 (Introduction) under the section "The Role of PacifiCorp's Integrated Resource Planning". The company notes the challenges in complying with multi-state integrated planning given differing state energy policies and resource preferences.
Guideline 11: Reliability		
11	Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.	See the response to 1.c.3.1 above. Volume I, Chapter 9 (Modeling and Portfolio Selection Results) walks through the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO_2 cost levels were used to inform the cost/risk tradeoff analysis.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp contracted with DNV to provide estimates of expected private generation penetration. The study was incorporated in the analysis as a deduction to load. Sensitivities looked at both high and low penetration rates for private generation. The study is included in Volume II, Appendix L (Private Generation Study).
Guideline 13: Resource Acquisition		

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
13.a	An electric utility should, in its IRP: 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. 3. Identify any Benchmark Resources it plans to consider in competitive bidding.	Volume I, Chapter 10 (Action Plan) outlines the procurement approaches for resources identified in the preferred portfolio. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 10 (Action Plan). PacifiCorp has not at this time identified any specific benchmark resources it plans to consider in the competitive bidding process summarized in the 2023 IRP action plan.
13.b	For gas utilities only.	Not Applicable
Flexible Capacity Resources		
1	Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20- year planning period.	PacifiCorp as met this requirement in Volume II, Appendix F (Flexible Reserve Study).
2	Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period.	PacifiCorp as met this requirement in Volume II, Appendix F (Flexible Reserve Study).
3	Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.	PacifiCorp as met this requirement in Volume II, Appendix F (Flexible Reserve Study).

Table B.4– Utah Public Service Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Public Service Commission of Utah responsibility.
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the 2023 IRP process.
3	Prudence reviews of new resource acquisitions will occur during ratemaking proceedings.	Not an IRP requirement as the Commission acknowledges that prudence reviews will occur during ratemaking proceedings, outside of the IRP process.
4	PacifiCorp's integrated resource planning process will be open to the public at all stages. The Commission, its staff, the Division, the Committee, appropriate Utah state agencies, and other interested parties can participate. The Commission will pursue a more active-directive role if deemed necessary, after formal review of the planning process.	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction). A description of public-input meetings is provided in Volume II, Appendix C (Public Input). Public-input meeting materials can also be found on PacifiCorp's website at: www.pacificorp.com/energy/integrated- resource-plan/public-input-process.html
5	Consideration of environmental externalities and attendant costs must be included in the integrated resource planning analysis.	PacifiCorp used a scenario analysis approach along with externality cost adders to model environmental externality costs. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) for a description of the methodology employed, including how CO_2 cost uncertainty is factored into the determination of relative portfolio performance through a base case planning assumption and other price-policy scenarios.
6	The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.	Supply, transmission, and demand-side resources were evaluated on a comparable basis using Plexos optimization models. Also see the response to number 4.b.ii below.
7	Avoided cost should be determined in a manner consistent with the company's Integrated Resource Plan.	Consistent with Utah rules, PacifiCorp determination of avoided costs in Utah will be handled in a manner consistent with the IRP, with the caveat that the costs may be updated if better information becomes available.
8	The planning standards and guidelines must meet the needs of the Utah service area, but since coordination with other jurisdictions is important, must not ignore the rules governing the planning process already in place in other jurisdictions.	This IRP was developed in consultation with parties from all state jurisdictions and meets all formal state IRP guidelines.
9	The company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	Volume I, Chapter 10 (Action Plan) describes the linkage between the 2023 IRP preferred portfolio and December 2022 business plan resources. Significant resource differences are highlighted. The business plan portfolio was run consistent with requirements outlined in the Order issued by the Utah Public Service Commission on September 16, 2016, Docket No. 15-035-04.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	Volume I, Chapter 8 (Modeling and Portfolio Evaluation) outlines the portfolio performance evaluation and preferred portfolio selection process, while Chapter 9 (Modeling and Portfolio Selection Results) chronicles the modeling and preferred portfolio selection process. This IRP also addresses concerns expressed by Utah stakeholders and the Utah commission concerning comprehensiveness of resources considered, consistency in applying input assumptions for portfolio modeling, and explanation of PacifiCorp's decision process for selecting top-performing portfolios and the preferred portfolio.
2	The company will submit its Integrated Resource Plan biennially.	The company submitted its last IRP on September 1, 2021, and filed this IRP on March 31, 2023, as an informational filing, meeting the requirement. PacifiCorp requested and was granted a 60 day extension of time to file the final 2023 IRP on May 31, 2023 in Docket No. 23-035-10.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction). A record of public meetings and a summary of feedback and public comments is provided in Volume II, Appendix C (Public Input).
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic variability, covering both capacity and energy. Details concerning the load forecasts used in the 2021 IRP are provided in Volume I, Chapter 7 (Resource Options) and Volume II, Appendix A (Load Forecast).
4.a.i	The forecasts will be made by jurisdiction and by general class and will differentiate energy and capacity requirements. The company will include in its forecasts all on-system loads and those off- system loads which they have a contractual obligation to fulfill. Non-firm off-system sales are uncertain and should not be explicitly incorporated into the load forecast that the utility then plans to meet. However, the Plan must have some analysis of the off-system sales market to assess the impacts such markets will have on risks associated with different acquisition strategies.	Load forecasts are differentiated by jurisdiction and differentiate energy and capacity requirements. See Volume I, Chapter 6 (Load and Resource Balance) and Volume II, Appendix A (Load Forecast). Non-firm off-system sales are not incorporated into the load forecast. Off-system sales markets are included in IRP modeling and are used for system balancing purposes.
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	Volume II, Appendix A (Load Forecast) documents how demographic and price factors are used in PacifiCorp's load forecasting methodology.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the Plexos optimization models for both supply side and demand side alternatives. See explanation in Volume I, Chapter 7 (Modeling and Portfolio Evaluation) and the results in Volume I, Chapter 9 (Modeling and Portfolio Selection Results). Resource options are summarized in Volume I, Chapter 7 (Resource Options).
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp included supply curves for Demand Response (dispatchable/schedulable load control) and Energy Efficiency in its capacity expansion model. Details are provided in Volume I, Chapter 7 (Resource Options).
4.b.ii	An assessment of all technically feasible generating technologies including renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, energy storage, and Energy Gateway transmission configurations. Newly evaluated resources in this IRP include offshore wind and long-term storage options. Volume I, Chapters 7 (Resource Options) and 8 (Modeling and Portfolio Evaluation) contain assumptions and describe the process under which PacifiCorp developed and assessed these technologies and resources.
4.b.iii	The resource assessments should include: life expectancy of the resources, the recognition of whether the resource is replacing/adding capacity or energy, dispatchability, lead-time requirements, flexibility, efficiency of the resource and opportunities for customer participation.	PacifiCorp captures and models these resource attributes in its IRP models. Resources are defined as providing capacity, energy, or both. The DSM supply curves used for portfolio modeling explicitly incorporate estimated rates of program and event participation. The private generation study, modeled as a reduction to load, also considered rates of participation. Replacement capacity is considered in the case of early coal unit retirements as evaluated in this IRP as an alternative to coal unit environmental investments.
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	A description of the role of competitive bidding and other procurement methods is provided in Volume I, Chapter 10 (Action Plan).
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2023-2042).
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	The IRP action plan is provided in Volume I, Chapter 10 (Action Plan). A status report of the actions outlined in the previous action plan (2019 IRP Update) is provided in Volume I, Chapter 10 (Action Plan). In Volume I, Chapter 10 (Action Plan) Table 10.1 identifies actions anticipated in the next two-to-four years.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
4.f	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.	Volume I, Chapter 10 (Action Plan) includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, change in load growth, extension of federal renewable resource tax incentives and procurement delays.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Volume I, Chapter 7 (Resource Options). The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: ● Relevant portfolios were evaluated using a range of CO_2 price-policy scenarios. ● A discussion of environmental policy status and impacts on utility resource planning is provided in Volume I, Chapter 3 (Planning Environment). ● State and proposed federal public policy preferences for clean energy are considered for development of the preferred portfolio, which is documented in Volume I, Chapter 9 (Modeling and Portfolio Selection Results). In addition, distinct state filings also address clean energy. ● Volume II, Appendix G (Plant Water Consumption) reports historical water consumption for PacifiCorp's thermal plants.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
4.h	An evaluation of the financial, competitive, reliability, and operational 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. The company will identify who should bear such risk, the ratepayer, or the stockholder.	The handling of resource risks is discussed in Volume I, Chapter 10 (Action Plan), and covers managing environmental risk for existing plants, risk management and hedging and treatment of customer and investment risk. Transmission expansion risks are discussed in Volume I, Chapter 4 (Transmission). Resource capital cost uncertainty and technological risk is addressed in Volume I, Chapter 7 (Resource Options). For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for new thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Volume I, Chapter 10 (Action Plan).
4.i	Considerations permitting flexibility in the planning process so that the company can take advantage of opportunities and can prevent the premature foreclosure of options.	Flexibility in the planning and procurement processes is highlighted in Volume I, Chapter 10 (Action Plan).
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	PacifiCorp examined the trade-off between portfolio cost and risk, taking into consideration a broad range of resource alternatives defined with varying levels of dispatchability. This trade-off analysis is documented in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
4.k	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, to show how explicit consideration of them might affect selection of resource options. The company will attempt to quantify the magnitude of the externalities, for example, in terms of the number of emissions released and dollar estimates of the costs of such externalities.	PacifiCorp incorporated environmental externality costs for CO_2 and costs for complying with current and proposed U.S. EPA regulatory requirements. For CO_2 externality costs, the company used scenarios with various compliance requirements to capture a reasonable range of cost impacts. These modeling assumptions are described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
4.l	A narrative describing how current rate design is consistent with the company's integrated resource planning goals and how changes in rate design might facilitate integrated resource planning objectives.	See Volume I, Chapter 3 (Planning Environment). The role of Class 3 DSM (price response programs) at PacifiCorp and how these resources are modeled in the IRP are described in Volume I, Chapter 7 (Resource Options).

5	PacifiCorp will submit its IRP for public comment, review and acknowledgment.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public-input meetings and solicited/and received feedback at various times when developing the 2023 IRP. The materials shared with stakeholders at these meetings, outlined in Volume I, Chapter 2 (Introduction), is consistent with materials presented in Volumes I and II of the 2023 IRP report. Public-input meetings materials can be located on PacifiCorp's website at: www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html PacifiCorp requested and responded to comments from stakeholders in throughout its 2023 IRP process. The company also considered comments received via Stakeholder Feedback Forms that can be located on PacifiCorp's website at: www.pacificorp.com/energy/integrated-resource-plan/comments.html A total of 133 Stakeholder Feedback Forms were received and responded to during the 2023 IRP public-input process.
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of the Plan. The Commission will review the Plan for adherence to the principles stated herein and will judge the merit and applicability of the public comment. If the Plan needs further work the Commission will return it to the company with comments and suggestions for change. This process should lead more quickly to the Commission's acknowledgment of an acceptable Integrated Resource Plan. The company will give an oral presentation of its report to the Commission, and all interested public parties. Formal hearings on the acknowledgment of the Integrated Resource Plan might be appropriate but are not required.	Not addressed; this is a post-filing activity.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
7	Acknowledgment of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

Washington IRP requirements and the Washington IRP Two-Year Progress Report

Requirements for the Two-Year Progress Report are significantly reduced compared to the four-year filing of the full IRP. Requirements are focused primarily on fundamental data input updates necessary to update some interim and specific targets and report progress on other elements of the Clean Energy Implementation Plan. Nonetheless, PacifiCorp has attempted to adhere to all IRP filing requirements where possible in addition to the requirements of the Two-Year Progress Report, as detailed below.

Table B.5 – Washington Utilities and Transportation Commission IRP Standard and Guidelines to Implement CETA Rules (RCW 19.280.030 and WAC 480-100-620 through WAC 480-100-630) per Commission General Order R-601.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-625(1) and (4)	Integrated resource plan updated every four years, with a progress report at least every two years.	The PacifiCorp IRP is published every two years with updates in the off cycles. This exceeds Washington State requirements. New to this IRP cycle is the requirement to file an IRP Two-Year Progress Report. This document constitutes the Progress Report.
WAC 480-100-620(1)	Unless otherwise stated, all assessments, evaluations, and forecasts comprising the plan should extend over the long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) planning horizon.	PacifiCorp's 2023 (and prior) IRPs span a 20-year long-term planning horizon. Additional analysis may extend beyond the 20-year horizon but not in the form of optimization modeling runs, as sufficient data is unavailable, resources insufficient and run times, which advance geometrically and not linearly with added years, are impractical. Rather than extrapolate all data inputs to cover longer periods, PacifiCorp extrapolates the optimized results.
WAC 480-100-620(2)	Plan includes range of forecasts of projected customer demand that reflect effect of economic forces on electricity consumption.	Variant load forecast cases will include High/low load, 1-in-20 load, High/low private generation, New Load and No Climate change load scenarios. Other load variants will be considered based on stakeholder feedback and model outcomes.
WAC 480-100-620(2)	Plan includes range of forecasts of projected customer demand that address changes in the number, type, and efficiency of electrical end-uses.	PacifiCorp has provided detail on load forecasts in Volume II, Appendix A (Load Forecast). Information can also be found in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(3)(a)	Plan includes load management assessments that are cost-effective and commercially available, including current and new policies and programs to obtain:	The IRP is informed by the company’s current conservation potential assessment, which is available on PacifiCorp’s website. Additional information on the load management assessments can be found in Volume II, Appendix D (Demand-Side Management Programs).

WAC 480-100-620(3)(a)	- all cost-effective conservation, efficiency, and load management improvements;	IRP modeling optimally selects all cost-effective energy efficiency and demand response in each case portfolio as a part of core model functionality. Results are reported for all portfolios in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-109-100(2)	- ten-year conservation potential used in the concurrent biennial conservation plan consistent with RCW 19.285.040(1);	The IRP is informed by the current conservation potential assessment, which is available on PacifiCorp's website. Volume I, Chapter 6 (Load and Resource Balance) provides additional detail.
	- identification of opportunities to develop combined heat and power as an energy and capacity resource; and	Combined heat and power are addressed as a component of the Private Generation Study, which is included in Volume II, Appendix L (Private Generation Study).
No.	**Requirement**	**How the Guideline is Addressed in the 2023 IRP**
WAC 480-100-620(3)(b)	- all demand response (DR) at the lowest reasonable cost (LRC).	IRP modeling optimally selects all cost-effective energy efficiency and demand response in each case portfolio as a part of core model functionality. Results are reported for all portfolios in Volume II, Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(3)(b)	Plan includes assessments of distributed energy programs and mechanisms pertaining to energy assistance and progress toward meeting energy assistance need, including but not limited to the following: - Energy efficiency and CPA, - Demand response potential, - Energy assistance potential	IRP modeling considers and selects energy efficiency and demand response potential, and distributed energy programs. Evaluation is detailed in Volume I, Chapter 8 (Modeling and Portfolio), and Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(3)(b)	Plan assesses a forecast of distributed energy resources (DER) that may be installed by the utility's customers via a planning process pursuant to RCW 19.280.100(2).	PacifiCorp has worked with DNV Consulting to prepare a Private Generation Study, which assesses distributed and customer-sited resources. Customer preference resources are also assessed as part of the portfolio selection process. Additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(3)(b)	Plan includes effect of DERs on the utility's load and operations.	The impacts of DERs on PacifiCorp's utility load and operations are assessed as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation). Inputs are assessed as part of Volume II, Appendix L (Private Generation Study).
WAC 480-100-620(3)(b)	If utility engages in a DER planning process, which is strongly encouraged, IRP should include a summary of the process planning results.	PacifiCorp understands this requirement and will include a summary in future integrated resource plans, if applicable. Also, summaries of our DER planning processes can be found in the conservation potential assessment and private generation studies posted on our website.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(4)	Plan assesses wide range of conventional generating resources.	PacifiCorp considered a wide range of resources including renewables, demand-side management, energy storage, distributed energy resources, power purchases, thermal resources, and transmission. Volume I, Chapter 7 (Resource Options) provides relevant detail on conventional generating resources.
WAC 480-100-620(5)	In making new investments, plan considers acquisition of existing and new renewable resources at LRC.	Cost and performance data for all resource types is evaluated and entered as a model input for the optimal selection of resources. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
See **WA-UTC energy storage policy statement** (UE-151069 & UE-161024 consolidated)	Plan assesses energy storage resources.	Energy storage resources are considered as part of the supply-side resource table, found in Volume I, Chapter 7 (Resource Options). Energy storage potential is assessed as part of Volume II, Appendix N (Energy Storage Potential Evaluation).
WAC 480-100-620(5)	Plan assesses nonconventional generating, integration, and ancillary service technologies.	Compressed air storage and advanced nuclear resources are represented in the Supply Resource Table, which is posted on PacifiCorp's IRP website and included as Volume I, Chapter 7 (Resource Options). All resource types are appropriately subject to integration and ancillary services determination, including transmission upgrade costs, reserve holding capability and additional reserve requirements that are particular to technologies. These factors are inherent to every portfolio optimization run.
WAC 480-100-620(6)	Plan assesses the availability of regional generation and transmission capacity for purposes of delivery of electricity to customers.	Regional generation is incorporated into market availability and price forecasts, which are described and analyzed in Volume I, Chapter 3 (Planning Environment), Chapter 5 (Reliability and Resiliency). Transmission and resource options are described in Volume I, Chapter 4 (transmission) and Chapter 7 (Resource Options).
WAC 480-100-620(6)	Plan assesses utility's regional transmission future needs and the extent	Regional transmission is represented through markets and region-based price forecasting, while PacifiCorp's transmission system is represented by firm

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
	transfer capability limitations may affect the future siting of resources.	transmission rights and endogenous transmission upgrade options. These factors are discussed in the Volume I, Chapter 7 (Resource Options) and Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(7)	Plan compares benefits and risks of purchasing power or building new resources.	As a component of core modeling functionality, all competing resources are evaluated to determine each optimal portfolio. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(7)	Plan compares all identified resources according to resource costs, including:	The comparison of resources on a cost-risk basis is core functionality of PacifiCorp's optimization modeling. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(7)	- transmission and distribution delivery costs;	PacifiCorp's transmission system is represented by firm transmission rights and endogenous transmission upgrade options. Transmission dependencies implying additional resource costs are included in the optimization, resulting in a reasonable comparison of resource costs. Additional information can be found in Volume I, Chapter 7 (Resource Options), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(7)	- risks, including environmental effects and the social cost of GHG emissions;	The Company has conducted six SC-GHG cases, three of which were evaluated under a range of additional price-policy conditions. The cases evaluated are described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(7)	- benefits accruing to the utility, customers, and program participants (when applicable); and	Benefits are characterized by present value revenue requirement differentials, emissions, reserve and load deficiencies, robustness across stochastic variances and additional factors as may emerge from modeling results. In addition to modeling outcomes presented in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), incremental costs relative to the Washington Clean Energy Implementation Plan are discussed in Volume II, Appendix O (Washington Two-Year Progress Report Additional Elements).
WAC 480-100-620(7)	- resource preference public policies adopted by WA State or the federal government.	The preferred portfolio selected in the 2023 IRP process is compliant with all policy requirements. A summary of the policy environment is included as Volume I, Chapter 3 (Planning Environment), and a description of the portfolio runs in compliance with policy is included as Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(7)	Plan includes methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage, and addressing overgeneration events.	IRP modeling endogenously considers "overgeneration" in dispatch and curtails resources appropriately. These curtailments are an inherent component of the cost and risk valuation of each portfolio, and is a driver for the optimal size, type and location of selected resources.
WAC 480-100-620(8)	Plan assesses and determines resource adequacy metrics.	For the 2023 IRP, resource adequacy is evaluated as a core model function, where each portfolio is obligated to meet reliability requirements including varying degrees of quality of operating reserves. This is described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(8)	Plan identifies an appropriate resource adequacy requirement.	PacifiCorp has addressed this requirement as described in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(8)	Plan measures corresponding resource adequacy metric consistent with prudent utility practice in eliminating coal-fired generation by 12/31/2025 (RCW 19.405.030), attaining GHG neutrality by 1/1/2030 (RCW 19.405.040), and achieving 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050).	PacifiCorp has addressed this requirement as pertains to requirements for the Clean Energy Transformation Act and the Two-Year Progress Report as described in Volume I, Chapter 6 (Load and Resource Balance), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(9)	Plan reflects the cumulative impact analysis conducted under RCW 19.405.140, and includes an assessment of:	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.
WAC 480-100-620(9)	- energy and nonenergy benefits;	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.
WAC 480-100-620(9)	- reduction of burdens to vulnerable populations and highly impacted communities;	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.
WAC 480-100-620(9)	- long-term and short-term public health and environmental benefits, costs, and	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(9)	- long-term and short-term public health and environmental risks; and	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.
WAC 480-100-620(9)	- energy security and risk.	Please see Appendix O for details regarding the Company's plan for reporting on metrics related to CBIs.
WAC 480-100-620(10)	Utility should include a range of possible future scenarios and input sensitivities for testing the robustness of the utility's resource portfolio under various parameters, including the following required components:	A wide range of cases and sensitivities under various price-policy futures have been included, as discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(10)	*CETA counter factual scenario* - describe the alternative LRC and reasonably available portfolio that the utility would have implemented if not for the requirement to comply with RCW 19.405.040 and RCW 19.405.050, as described in WAC 480-100-660(1).	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(10)	*Climate change scenario* - incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(10)	*Maximum customer benefit sensitivity* - model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(11)	Plan must integrate demand forecasts and resource evaluations into a long-range IRP solution.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(11)	IRP solution or preferred portfolio must describe the resource mix that meets current and projected needs.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 9 (Modeling and Portfolio Selection).

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(11)(a)	Preferred portfolio must include narrative explanation of the decisions made, including how the utility's long-range IRP solution:	See individual entries below.
WAC 480-100-620(11)(a)	- achieves requirements for eliminating coal-fired generation by 12/31/2025 (RCW 19.405.030);	PacifiCorp will remove coal-fired generation from Washington's allocation of electricity by 2025 and will continue to analyze this pending further resolution of interpretive issues by the Commission. Additional information can be found in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(11)(a)	- attains GHG neutrality by 1/1/2030 (RCW 19.405.040); and	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results), and Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(a)	- achieves 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050) at LRC,	This is outside of the Two-Year Progress Report timeline, but is addressed as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(a)	- achieves 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050), considering risk.	This is outside of the Two-Year Progress Report timeline, but the pathway to 2045 is addressed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(c)	Consistent with RCW 19.285.040(1), preferred portfolio shows pursuit of all cost-effective, reliable, and feasible conservation and efficiency resources, and DR.	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(d) and I	Preferred portfolio considers acquisition of existing renewable new resources and relies on renewable resources and energy storage, insofar as doing so is at LRC,	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(d) and (e)	Preferred portfolio considers acquisition of existing renewable new resources and relies on renewable resources and energy storage, considering risks.	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(f)	Preferred portfolio maintains and protects the safety, reliable operation, and balancing of the utility's electric system, including mitigating over-generation events and achieving identified resource adequacy requirements.	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 6 (Load and Resource Balance).

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(11)(g)	Preferred portfolio ensures all customers are benefiting from the transition to clean energy through the:	
WAC 480-100-620(11)(g)	- equitable distribution of energy and nonenergy benefits; reduction of burdens to vulnerable populations and highly impacted communities;	Please see Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(g)	- long-term and short-term public health and environmental benefits; reduction of costs and risks; and	Please see Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(g)	- energy security and resiliency.	Please see Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(h)	Preferred portfolio: assesses the environmental health impacts to highly impacted communities,	Please see Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(11)(i)	- analyzes and considers combinations of DER costs, benefits, and operational characteristics (incl. ancillary services) to meet system needs,	Detail is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(11)(j)	- incorporates the social cost of GHG emissions as a cost adder.	Detail is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(12)	Utility must develop a ten-year **clean energy action plan** (CEAP) for implementing RCW 19.405.030 through 19.405.050 at LRC, and at an acceptable resource adequacy standard. The CEAP will:	The Company's CEAP was provided in the 2021 Integrated Resource Plan published September 1, 2021.
WAC 480-100-620(12)(b)	- identify and be informed by utility's ten-year CPA per RCW 19.285.040(1);	The Clean Energy Action Plan is not a component of the IRP Two-Year Progress Report.
WAC 480-100-620(12)(c)	- demonstrate that all customers are benefiting from the transition to clean energy;	The Clean Energy Action Plan is not a component of the IRP Two-Year Progress Report.
WAC 480-100-620(12)(d)	- establish a resource adequacy requirement;	PacifiCorp establishes resource adequacy at a system level, and the resource adequacy requirement is explained in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(12)(e)	- identify the potential cost-effective DR and load management programs that may be acquired;	This requirement is met in Volume I, Chapter 9 (Modeling and Portfolio Selection Results) and Volume II, Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(12)(f)	- identify renewable resources, non emitting electric generation, and DERs that may be acquired and evaluate how each identified resource may be expected to contribute to meeting the utility's resource adequacy requirement;	This is described at the system-level as part of PacifiCorp's resource planning process. Volume I, Chapter 7 (Resource Options), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection) provide additional detail.

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(12)(g)	- identify any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities; and	This is described at the system level in Volume I, Chapter 4 (Transmission) and also within PacifiCorp's Volume I, Chapter 10 (Action Plan).
WAC 480-100-620(12)(h)	- identify the nature and possible extent to which the utility may need to rely on alternative compliance options, if appropriate.	Please see Volume II Appendix O (Washington IRP Two-Year Progress Report Additional Elements).
WAC 480-100-620(12)(i)	Plan (both IRP and CEAP) considers cost of greenhouse gas emissions as a **cost adder** equal to the cost per metric ton of carbon dioxide emissions, using the two and one-half percent discount rate, listed in Table 2, Technical Support Document: Technical update of the social cost of carbon (SCC) for regulatory impact analysis under Executive Order 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016, as adjusted by the Commission to reflect the effect of inflation.	PacifiCorp updated its social cost of greenhouse gas pricing consistent with DOCKET U-190730 ORDER 03, which updates this specification.
WAC 480-100-620(13)	Plan must include an analysis and summary of the estimated avoided cost for each supply- and demand-side resource, including (but not limited to):	A new assessment of avoided cost is not a requirement of the Two-Year Progress Report; however, future determinations of avoided cost will follow the guidelines below.
WAC 480-100-620(13)	- energy,	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- capacity,	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- transmission,	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- distribution, and	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- GHG emissions.	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-100-620(13)	Listed energy and non-energy impacts should specify to which source party they accrue (e.g., utility, customers, participants, vulnerable populations, highly impacted communities, general public).	The file labeled "2023 CPA - Appendix E - WA Non-Energy Impact Mapping", as part of the CPA supplemental materials posted on the website, maps the accrual of NEIs to various groups consistent with WAC 480-100-620(13).

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
WAC 480-106-040	Plan provides information and analysis used to inform annual purchases of electricity from qualifying facilities, including a description of the:	A new assessment of avoided cost is not a requirement of the Two-Year Progress Report; however, future determinations of avoided cost will follow the guidelines below.
WAC 480-106-040	- avoided cost calculation methodology used;	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-106-040	- avoided cost methodology of energy, capacity, transmission, distribution, and emissions averaged across the utility; and	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-106-040	- resource assumptions and market forecasts used in the utility's schedule of estimated avoided cost, including (but not limited to): cost assumptions, production estimates, peak capacity contribution estimates, and annual capacity factor estimates.	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(14)	To maximize transparency, the utility should submit data input files supporting the plan in native file format (e.g., supporting spreadsheets in Excel, not PDF file format).	PacifiCorp will make data available in the native file format consistent with practice in prior IRPs.
WAC 480-100-620(15)	Information relating to purchases of electricity from qualifying facilities. Each utility must provide information and analysis that it will use to inform its annual filings required under chapter 480-106 WAC. The detailed analysis must include, but is not limited to, the following components:	
WAC 480-100-620(15)(a)	A description of the methodology used to calculate estimates of the avoided cost of energy, capacity, transmission, distribution and emissions averaged across the utility; and	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(15)(b)	(b) Resource assumptions and market forecasts used in the utility's schedule of estimated avoided cost required in WAC 480-106-040 including, but not limited to, cost assumptions, production estimates, peak capacity contribution estimates and annual capacity factor estimates.	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(16)	Plan must summarize substantive changes to modeling methodologies or inputs that change the utility's resource need, as compared to the utility's previous IRP.	An assessment of modeling methodology is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
WAC 480-100-620(17)	Utility must summarize:	
WAC 480-100-620(17)	- public comments received on the draft IRP,	This is included in Volume II, Appendix C (Public Input).

WAC 480-100-620(17)	- utility's responses to public comments, and	This is included in Volume II, Appendix C (Public Input).
WAC 480-100-620(17)	- whether final plan addresses and incorporates comments raised.	This is included in Volume II, Appendix C (Public Input).

Table B.6 – Wyoming Public Service Commission Guidelines

No.	Requirement	How the Guideline is Addressed in the 2023 IRP
A	The public comment process employed as part of the formulation of the utility's IRP, including a description, timing and weight given to the public process;	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction) and in Volume II, Appendix C (Public Input).
B	The utility's strategic goals and resource planning goals and preferred resource portfolio;	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) documents the preferred resource portfolio and rationale for selection. Volume I, Chapter 10 (Action Plan) constitutes the IRP action plan and the descriptions of resource strategies and risk management.
C	The utility's illustration of resource need over the near-term and long-term planning horizons;	See Volume I, Chapter 6 (Load and Resource Balance).
D	A study detailing the types of resources considered;	Volume, I Chapter 7 (Resource Options), presents the resource options used for resource portfolio modeling for this IRP.
E	Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP;	A comparison of resource changes relative to the 2021 IRP is presented in Volume I, Chapter 10 (Action Plan). A chart comparing the peak load forecasts for the 2019 IRP, and 2021 IRP is included in Volume II, Appendix A (Load Forecast Details).
F	The environmental impacts considered;	Portfolio comparisons for CO2 and a broad range of environmental impacts are considered, including prospective early retirement and gas conversions of existing coal units as alternatives to environmental investments. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection) as well as Volume II, Appendix J (Stochastic Simulation Results).
G	Market purchases evaluation;	Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in the 2021 IRP.
H	Reserve Margin analysis; and	Reserve margin analysis is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
I	Demand-side management and conservation options;	See Volume I, Chapter 7 (Resource Options) and Volume II, Appendix D (Demand-side Management) for a detailed discussion on DSM and energy efficiency resource options. Additional information on energy efficiency resource characteristics is available on the company's website.

APPENDIX C – PUBLIC INPUT PROCESS

A critical element of this Integrated Resource Plan (IRP) is the public-input process. PacifiCorp has pursued an open and collaborative approach involving the commissions, customers, and other stakeholders in PacifiCorp's IRP prior to making resource planning decisions. Since these decisions can have significant economic and environmental consequences, conducting the IRP with transparency and full participation from interested and affected parties is essential to achieve long-term planning objectives.

Stakeholders have been involved in the development of the 2023 IRP from the beginning. The public-input meetings held beginning in January 2022 were the cornerstone of the direct public-input process, and there have been 10 public-input meetings held as part of the 2023 IRP development cycle. Due to restrictions and concerns surrounding COVID-19, all meetings have been held via phone conference, with no in-person participation.

The IRP public-input process also included state-specific stakeholder dialogue sessions held in the summer of 2022. The goal of these sessions was to capture key IRP issues of most concern to each state, as well as to discuss how to tackle these issues from a system planning perspective. PacifiCorp wanted to ensure stakeholders understood IRP planning principles. These meetings continued to enhance interaction with stakeholders in the planning cycle and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during public- input meetings.

PacifiCorp solicited agenda item recommendations from stakeholders in advance of the state meetings. There was additional open time to ensure participants had adequate opportunity for dialogue.

PacifiCorp's integrated resource plan website houses feedback forms included in this filing. This standardized form allows stakeholders to provide comments, questions, and suggestions. PacifiCorp also posts its responses to the feedback forms at the same location. Feedback forms and PacifiCorp's responses can be found via the following link: https://www.pacificorp.com/energy/integrated-resource-plan/comments.html.

Participant List

PacifiCorp's 2023 IRP continues to be a robust process involving input from many parties. Participants included commissions, stakeholders, and industry experts. Among the organizations that have been represented and actively involved in this collaborative effort are:

Commissions

- California Public Utilities Commission
- Idaho Public Utilities Commission
- Oregon Public Utility Commission
- Public Service Commission of Utah
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission

Stakeholders and Industry Experts

- ESS, INC
- Renewable Northwest
- SLC Corp
- Utah Division of Public Utilities
- Western Resource Advocates
- Holland & Hart
- Sierra Club
- Utah Clean Energy
- Interwest Energy Alliance
- Powder River Basin Resource Council
- Northwest Energy Coalition
- Fervo Energy
- Washington Utilities and Transportation Commission
- Renewable Energy Coalition
- Western Energy Storage Task Force
- Enyo
- Apex
- City of Kemmerer Wyoming
- NW Power Council
- Energy Trust of Oregon
- Oregon League of Women Voters
- Oregon Citizen Utility Board
- University of Wyoming
- Applied Energy Group
- Intermountain Wind-Colorado
- Meta
- City of SLC
- Wyoming Energy Consumers
- Wyoming Office of Consumer Advocates
- Powder River Basin Conservation League
- Wyoming Coalition of Local Governments

PacifiCorp extends its gratitude for the continued time and energy that participants have given to the IRP process. Their participation has contributed significantly to the quality of this plan

As mentioned above, PacifiCorp has hosted 10 public-input meetings, as well as five state meetings during the public-input process, with an additional public-input meeting scheduled for April 2023. During the 2023 IRP public-input process presentations and discussions have covered various issues regarding inputs, assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public-input meetings; the presentations can be located at:

ttps://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html

For the 2023 IRP, all General Public Meeting were held via conference call. The company has initiated making recording of these meeting publicly available through the IRP website:

General Meetings

February 25, 2022 – General Public Meeting (meeting materials provided to stakeholders on February 21, 2022)

- Conservation Potential Assessment (CPA)
- 2023 Supply-Side Resources
- 2021 IRP Update / 2023 IRP Overview
- 2023 IRP Public-Input Meeting Schedule

April 7, 2022 – General Public Meeting (meeting materials provided to stakeholders on April 4, 2022)

- Introductions
- 2023 Conservation Potential Assessment (CPA)
- Planning Environment Update
- Optimization Modeling Overview

May 12, 2022 – General Public Meeting (meeting materials provided to stakeholders on May 8, 2022)

- Conservation Potential Assessment
- Request For Proposals Update
- Price Curve Development Update
- Transmission Modeling
- Climate Modeling

June 10, 2022 – Public Meeting (meeting materials provided to stakeholders on June 6, 2022)

- Greenhouse Gas and Renewable Portfolio Standards
- State Policy Update
- Load Forecast Development

- Interconnection Options
- Supply-Side Resource Alternative Fuels
- 2021 IRP Acknowledgment Update
- Stakeholder Feedback

July 14, 2022 – Public Meeting (meeting materials provided to stakeholders on July 11, 2022)

- Draft Load Forecast Update
- Draft Private Generation Study
- Draft Distribution System Planning
- Renewable Portfolio Standards
- Stakeholder Feedback
- Ozone Transport Rule Update

September 1-2, 2022 – General Public Meeting (meeting materials provided to stakeholders on August 29, 2022)

Day One

- Inflation Reduction Act
- Supply Side Resource Table
- Existing Thermal Resource Options
- Transmission Modeling
- Price Forecasting
- Customer Preference
- Qualifying Facility Renewal
- Conservation Potential Assessment Draft Results

Day Two

- Conservation Potential Assessment Draft Results—Part II
- Stakeholder Feedback
- Market Reliance Update
- Oregon and Washington Update
- Generation Transition Equity and Justice
- Offshore Wind Workshop
- Hydro Forecasting Under Climate Change

October 13, 2022 – General Public Meeting (meeting materials provided to stakeholders on October 10, 2022)

- Supply-Side Resource Escalation
- Coal and Gas Modeling Options
- Regional Haze Update
- Load Forecast Update
- Transmission Upgrade Options
- Stochastics
- Reliability Assessment
- Portfolio Discussion

- Stakeholder Feedback Update

December 1, 2022 – General Public Meeting (meeting materials provided to stakeholders on November 28, 2022)

- Conservation Potential Assessment
- State Allocation and MSP Status Update
- Transmission Interconnection: Cluster Study 2 Results
- Initial Risk and Reliability Study Plan
- State Policy Update
- Stakeholder Feedback Form Update

January 13, 2023 – General Public Meeting (meeting materials provided to stakeholders on January 10, 2023)

- Extended Day-Ahead Market Update
- 2022 All-Source RFP Update
- Distribution System Planning update
- Transmission and Portfolio Selection Options Update
- Stakeholder Feedback Form Update

February 23, 2023 – General Public Meeting (meeting materials provided to stakeholders on February 20, 2023)

- Expanded Public Comment Opportunities
- Energy Efficiency Bundling
- Modeling Updates
- Forward Price Curve Updates
- Stakeholder Feedback Update

State-Specific Input Meetings

June 7, 2022 – Oregon State Meeting Part 1
June 7, 2022 – Wyoming State Meeting
June 21, 2022 – Oregon State Meeting Part 2
June 22, 2020 – Washington State Meeting
June 29, 2022 – Utah State Meeting
July 28, 2022 – Idaho State Meeting

Stakeholder Comments

For the 2023 IRP, PacifiCorp offered a Stakeholder Feedback Form which provided stakeholders a direct opportunity to provide comments, questions, and suggestions in addition to the opportunities for discussion at public-input meetings. PacifiCorp recognizes the importance of stakeholder feedback to the IRP public-input process. A blank form, as well as those submitted by stakeholders and PacifiCorp's response, can be located on the PacifiCorp website at the IRP comments webpage at: www.pacificorp.com/energy/integrated-resource-plan/comments.html.

As of March 23, 2023, PacifiCorp has received 36 Stakeholder Feedback Forms (including 4 pending forms) with hundreds of questions, comments, and recommendations. The Stakeholder Feedback Forms have allowed the company to review and summarize issues by topic as well as identify specific recommendations that were provided. Information collected is used to inform the 2023 IRP development process, including feedback related to process improvements and input assumptions, as well as responding directly to stakeholder questions. So far, Stakeholder Feedback Forms have been received from the following stakeholders:

- ESS, INC
- Renewable Northwest
- SLC Corp
- Utah Division of Public Utilities
- Western Resource Advocates
- Holland & Hart
- Sierra Club
- Utah Clean Energy
- Oregon Public Utilities Commission
- Interwest Energy Alliance
- Powder River Basin Resource Council
- Northwest Energy Coalition
- Fervo Energy
- Washington Utilities and Transportation Commission
- Renewable Energy Coalition
- Western Energy Storage Task Force

A discussion of topics included in the stakeholder feedback forms and how those topics were considered in the IRP are as follows:

IRP Public-Input Meeting Process/General Comments

Utah Division of Public Utilities submitted feedback stating that PacifiCorp must date its response to stakeholder forms, which the Company will continue to practice as a matter of policy.[1] Note that some entries below may appear to anticipate events that have already occurred because they are presented from the perspective of the responses given at that time.

Legislation

A multi-party request asked that PacifiCorp include time and materials in an upcoming 2023 IRP stakeholder presentation to discuss the benefits and opportunities that may be available through the Infrastructure Investment and Jobs Act, and how they may affect resource and transmission planning. PacifiCorp emphasized active collaboration with state jurisdictions, as most of the Infrastructure Investment and Jobs Act funds for grid projects will be allocated to each state. [2]

[1] Feedback Form 007; June 7, 2022
[2] Feedback Form 011; July 11, 2022

Sierra Club submitted a request that PacifiCorp elaborate on the relationship between the Inflation Reduction Act and load forecast assumptions. PacifiCorp responded stating that it has considered energy efficiency components of IRA for the Conservation Potential Assessment (CPA) by incorporating accelerated adoption rates for certain measure types eligible for IRA rebates and tax credits. It is difficult to exactly prescribe energy efficiency adjustments, but the Company did highlight changes for energy efficiency adoption rates at the December 1st PIM (Public Input Meeting) to reflect the IRA provisions noted in this stakeholder form.[3]

Load Forecasting

Western Resource Advocates recommend modeling two emissions reduction trajectories, in lieu of the "medium" and "high" carbon price scenarios, in addition to the social cost and no-cost GHG price assumptions.[4]

The Utah Division of Public Utilities requested an update on the 20-year weather pattern and Bureau of Reclamation Study, citing that the Reclamation study may not represent the most accurate climate change scenario in developing the IRP load forecast for Utah.[5]

Modeling Assumptions

Holland and Hart requested clarification on how PacifiCorp developed the GHG cost methodology and what third party resources were used to develop these costs. PacifiCorp provided this at a subsequent IRP Public Input Meeting and detailed the source and derivation of its assumptions around the social cost of greenhouse gas and assumptions on price of CO2 that are included in the company's IRP.[6]

Western Resource Advocates reiterated the request for information on Jim Bridger modeling, energy mix disclosure, GHG reporting, natural gas resources and hydrogen updates.[7]

Salt Lake City Corporation suggested that PacifiCorp evaluates wind and solar generation at an hourly rate vs. using monthly data. The Company acknowledged these limitations and is continuing to evolve the modeling process. [8]

The Oregon Public Utilities Commission requested that PacifiCorp determine the assumptions used on installation of new AC units, conversion rates and how the daily shape of electric vehicle charging is modeled.[9]

Sierra Club submitted a request inquiring about reliability resources, coal capacity factors. Carbon Capture Utilization and Sequestration (CCUS), load forecast adjustments, Jim Bridger fuel

[3] Feedback Form 030; December 7, 2022
[4] Feedback Form 012; June 23, 2022
[5] Feedback Form 021; September 9, 2022
[6] Feedback Form 013; June 27, 2022
[7] Feedback Form 015; July 11, 2022
[8] Feedback Form 016; July 14, 2022
[9] Feedback Form 019; August 5, 2022

contracts and the Inflation Reduction Act. PacifiCorp responded to this request at length and the response is publicly available on the Company IRP website. [10]

Utah Clean Energy submitted a stakeholder request outlining the following questions pertaining to the Lila Canyon coal mine fire including efforts to extinguish the fire, operational and workforce implications, reliability and fuel risk assumptions and impacts to 2023 IRP Plexos modeling. PacifiCorp responded to the request at length and the response is publicly available on the Company IRP website. [11]

Natrium Demonstration Project

Powder River Basin Resource Council requested updates on Natrium project risk considerations, fuel availability for project longevity and viable waste disposal options. PacifiCorp responded to this request at length and the information is available to the public online. [12]

The Washington Utilities and Transportation Commission submitted feedback noting concerns with the timeline for the release of the 2023 IRP preferred portfolio, modeling updates for the Natrium project following the announcement of a two-year delay and several procedural observations from IRP Public Input Meeting Series. PacifiCorp responded stating that it is the nature of IRP modeling and preparatory work that results must be confirmed before reporting and that all results are dependent upon ongoing work that is also subject to change. In response to emergent conditions which drive IRP timing, such as federal and state legislation, the Company is providing additional opportunities for public feedback after the March 31st filing and plans to file an addendum as needed and responsive to stakeholders.[13]

Natural Gas

Salt Lake City Corporation noted that PacifiCorp should study whether a battery with a grid forming inverter would provide a lower-cost alternative to natural gas spinning reserves. PacifiCorp outlined its position that it considers a wide range of technologies for supply-side resources[14]

The Utah Division of Public Utilities outlined potential concerns concerning stranded cost risks and resource depreciation from conventional natural gas generation and asked to re—evaluate the use of natural gas proxy resources. The Company has since modeled for new natural gas resources in the 2023 IRP.[15]

Utah Clean Energy submitted feedback asking how PacifiCorp will assess the impacts of methane leakage mitigation policies on natural gas portfolio outcomes. PacifiCorp responded by stating that the overall impact of the Methane emissions fee is ~1% or less and therefore negligible in the long-term natural gas price forecast[16]

[10] Feedback Form 029; November 28, 2022
[11] Feedback Form 031; November 23, 2022
[12] Feedback Form 028; October 5, 2022
[13] Feedback Form 035; January 17, 2023
[14] Feedback Form 009; June 16, 2022
[15] Feedback Form 018: July 21, 2022
[16] Feedback Form 023; September 8, 2022

Salt Lake City Corporation submitted feedback insisting that PacifiCorp should consider revising its natural gas price forecast higher in line with the Energy Information Administration short-term energy outlook. PacifiCorp indicated that the plan is to develop a forecast in September 2022 for use in the 2023 IRP, which will incorporate then-current natural gas prices and the latest long-term expectations. [17]

Plexos

Utah Division of Public Utilities Requests Company updates its Supply Side table with current operating and costs characteristics of natural gas fueled generation resources and allow the model to endogenously select natural gas generating resources as proxy resources, as it has done in the past. In the 2021 IRP, PacifiCorp ran an analysis which included options for new gas and for the 2023 IRP, the company has also assessed viable options for the inclusion of new gas in its base modeling. [18]

Reliability Assessment

Sierra Club noted several observations pertaining to reliability modeling, the Inflation Reduction Act, and a potential reduction in Transmission costs via the Energy Infrastructure Reinvestment (EIR) program. PacifiCorp responded stating that many of these observations would be fully addressed once the Company provides a comprehensive IRP by the March 31, 2023, filing date.[19]

Renewable Energy Resources

The Renewable Energy Coalition submitted a request outlining PacifiCorp's compliance with Oregon Public Utility Commission Order No. 22-178 and relevant data including the current QF renewal and success rate at varying capacities. PacifiCorp responded by posting supporting documentation on the Company Public Input Meeting website titled "QF Extension History", which provides an inventory of PacifiCorp qualifying facilities with other pertinent information. For supplemental data relating to qualifying facilities, this party was also directed to Oregon dockets LC-77 (2021 IRP) and LC-70 (2019 IRP).[20]

Resource Adequacy

Utah Clean Energy submitted a request that PacifiCorp develop three demand-side management sensitivities utilizing a low, medium, and high method of measurement. With the above feedback considered PacifiCorp instead utilizes a bottom-up modeling approach, which is better suited to adjustments to inputs for the purpose of informing sensitivities.[21]

[17] Feedback Form 009; June 16, 2022
[18] Feedback Form 010; July 7, 2022
[19] Feedback Form 034; January 18, 2023
[20] Feedback Form 032; January 3, 2023
[21] Feedback Form 017; July 21, 2022

State Energy Policy

Sierra Club requested updates on the Natrium Project, emissions profiles and state policy updates as they relate to the 2021 IRP acknowledgment, greenhouse gas reporting, Renewable Portfolio Standards, load forecast updates and compliance with the Washington Clean Energy Transformation Act (CETA).[22]

Washington Utilities and Transportation Commission Staff emphasized the statutory obligation for Washington utilities to incorporate the social cost of greenhouse gas into Washington allocated resource carbon cost assumptions. PacifiCorp responded by stating it is not aware of any language in RCW 19.280.030(3) and WAC 480-100-605 that requires utilities to include the SCGHG as their base carbon cost price-policy assumption for Washington-allocated resources.[23]

Supply-side Resource Costs/Supply-side Resource Table

ESS Inc requested an update from PacifiCorp on what changes are being made to the IRP modeling to determine marginal values of long-duration flow battery storage. The Company informed this party that it is commissioning a study of the cost and performance characteristics of energy storage and expects the study to include information specific to long duration flow batteries[24]

Renewable Northwest submitted a request that PacifiCorp consider DC-coupled solar + storage as well as other additional battery storage durations (medium and long-duration) as part of the supply-side resource table and subsequent IRP modeling. The Company responded indicating that Proxy resource modeling in the 2023 IRP is intended to be representative of costs and operational characteristics across a range of configurations and at this time is based on AC configuration but does not preclude other constructs from participating in all-source requests for proposals. [25]

Fervo Energy submitted a supply-side resources feedback outlining new cost assumptions that geothermal is becoming a less cost-prohibitive resource option that has the potential to create new jobs. In line with regulatory precedent, PacifiCorp remains committed to pursuing least- cost, least-risk preferred portfolio outcomes including geothermal when economically competitive.[26]

Renewable Northwest submitted feedback requesting updated transmission capacity metrics, offshore wind costs and recent modeling assumptions. PacifiCorp responded by stating that it has added 1,000 MW of offshore wind resources to the supply-side table among other more detailed information provided in this stakeholder form. [27]

The Western Energy Storage Task Force recommended the use of a specified forecast for utility-scale battery storage resources and proposed revising price modifications. PacifiCorp responded and re-affirmed that the costs presented in the September 1st Public Input Meeting do not include tax incentives implemented in the Inflation Reduction Act. Additional supply-side table reporting

[22] Feedback Form 014; July 1, 2022
[23] Feedback Form 024; September 20, 2022
[24] Feedback Form 001; February 24, 2022
[25] Feedback Form 002; March 3, 2022
[26] Feedback Form 020; August 23, 2022
[27] Feedback Form 022; September 14, 2022

will identify costs after accounting for tax incentives and all tax incentives are being accounted for in the 2023 IRP modeling process. The information about tax incentives presented to date is consistent with Table 7.1 in PacifiCorp's 2021 IRP. Resource information inclusive of tax incentives was provided in Table 7.2 of PacifiCorp's 2021 IRP and comparable information will be provided for the 2023 IRP.[28]

Salt Lake City Corporation submitted a request for the inclusion of a supply-side long-duration storage option with characteristics similar to the iron air battery announced earlier in the year. The Company responded by stating that it is considering longer duration energy storage similar to Form Energy Iron Air Battery in the 2023 IRP. PacifiCorp is commissioning a study of the cost and performance characteristics of energy storage and expects the study to include cost information specific to long duration flow batteries.[29]

Transmission

The Utah Division of Public Utilities requested supplemental study information and transmission topology, specifically referring to the Kiewit study on natural gas and hydrogen and requesting further information regarding why the Jim Bridger coal plant was moved to the PAC-east balancing authority. PacifiCorp responded directly to this stakeholder request and did not publish the response due to sensitivities around the Kiewit study.

The Interwest energy alliance inquired about whether or not PacifiCorp reviews the potential for reconductoring with advanced conductors, grid enhancing technology or advanced transmission technologies. PacifiCorp responded by saying it considers reconductoring with advanced conductors such as ACCC and ACSS if this provides a solution to thermal issues that are observed during outage conditions for regular studies such as Cluster Studies, Transmission Planning Assessment studies TPL001-4 and others[30]

Contact Information

PacifiCorp's IRP website: www.pacificorp.com/energy/integrated-resource-plan.html.

PacifiCorp requests any informal request be sent to the following address or email.

PacifiCorp
IRP Resource Planning Department
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232

Email Address:
IRP@PacifiCorp.com

[28] Feedback Form 027; October 27, 2022
[29] Feedback Form 003; May 12, 2022
[30] Feedback Form 033; January 10, 2023

APPENDIX D – DEMAND-SIDE MANAGEMENT

Introduction

This appendix reviews the studies and reports used to support the demand-side management (DSM) resource information used in the modeling and analysis of the 2023 Integrated Resource Plan (IRP). In addition, it provides information on the economic DSM selections in the 2021 IRP's Preferred Portfolio, a summary of existing DSM program services and offerings, and an overview of the DSM planning process in each of PacifiCorp's service areas.

Conservation Potential Assessment (CPA) for 2023-2042

Since 1989, PacifiCorp has developed biennial IRPs to identify an optimal mix of resources that balance considerations of cost, risk, uncertainty, supply reliability/deliverability, and long-run public policy goals. The optimization process accounts for capital, energy, and ongoing operation costs as well as the risk profiles of various resource alternatives, including traditional generation and market purchases, renewable generation, and DSM resources such as energy efficiency, and demand response or capacity-focused resources. Since the 2008 IRP, DSM resources have competed directly against supply-side options, allowing the IRP model to guide decisions regarding resource mixes, based on cost and risk.

The Conservation Potential Assessment (CPA) for 2023-2042,[1] conducted by Applied Energy Group (AEG) on behalf of PacifiCorp, primarily seeks to develop reliable estimates of the magnitude, timing, and costs of DSM resources likely available to PacifiCorp over the IRP's 20-year planning horizon. The study focuses on resources realistically achievable during the planning horizon, given normal market dynamics that may hinder or advance resource acquisition. Study results were incorporated into PacifiCorp's 2023 IRP and will be used to inform subsequent DSM planning and program design efforts. This study serves as an update of similar studies completed since 2007.

For resource planning purposes, PacifiCorp classifies DSM resources into four categories, differentiated by two primary characteristics: reliability and customer choice. These resource classifications can be defined as: demand response (e.g., a firm, capacity focused resource such as direct load control), energy efficiency (e.g., a firm energy intensity resource such as conservation), demand side rates (DSR) (e.g., a non-firm, capacity focused resource such as time of use rates), and behavioral-based response (e.g., customer energy management actions through education and information).

From a system-planning perspective, demand response resources can be considered the most reliable, as they can be dispatched by the utility. In contrast, behavioral-based resources are the least reliable due to the resource's dependence on voluntary behavioral changes. With respect to customer choice, demand response and energy efficiency resources should be considered involuntary in that, once equipment and systems have been put in place, savings can be expected to occur over a certain period. DSR and behavioral-based activities involve greater customer

[1] PacifiCorp's Demand-Side Resource Potential Assessment for 2023-2042, completed by AEG, can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

choice and control. This assessment estimates potential from demand response, energy efficiency, and DSR.

The CPA excludes an assessment of Oregon's energy efficiency resource potential, as this work is performed by Energy Trust of Oregon, which provides energy efficiency potential in Oregon to PacifiCorp for resource planning purposes.

Current DSM Program Offerings by State

Currently, PacifiCorp offers a robust portfolio of DSM programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp has the most up-to-date programs on its website.[2] Demand response and energy efficiency program services and offerings are available by state and sector. Energy efficiency services listed for Oregon, except for low-income weatherization services, are provided in collaboration with Energy Trust of Oregon.[3]

Table D.1 provides an overview of the breadth of demand response and energy efficiency program services and offerings available by Sector and State.

PacifiCorp has numerous DSR offerings currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), and residential seasonal rates (Idaho and Utah). System-wide, approximately 16,100 customers were participating in metered time-of-day and time-of-use programs as of December 31, 2022.

Savings associated with rate design are captured within the company's load forecast and are thus captured in the integrated resource planning framework. PacifiCorp continues to evaluate DSR programs for applicability to long-term resource planning.

PacifiCorp provides behavioral based offerings as well. Educating customers regarding energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts and messages, newsletters, school education programs, and personal contact. Load reductions due to behavioral activity will show up in demand response and energy efficiency program results and non-program reductions in the load forecast over time.

Table D.2 provides an overview of DSM related Wattsmart Outreach and Communication activities (Class 4 DSM activities) by state.

[2] Programs for Rocky Mountain Power can be found at www.rockymountainpower.net/savings-energy-choices.html and programs for Pacific Power can be found at www.pacificorp.com/environment/demand-side-management.html.
[3] Funds for low-income weatherization services are forwarded to Oregon Housing and Community Services.

Table D.1– Current Demand Response and Energy Efficiency Program Services and Offerings by Sector and State

Program Services & Offerings by Sector and State	California	Oregon	Washington	Idaho	Utah	Wyoming
Residential Sector						
Air Conditioner Direct Load Control					√	
Lighting Incentives	√	√	√	√	√	√
New Appliance Incentives	√	√	√	√	√	√
Heating And Cooling Incentives	√	√	√	√	√	√
Weatherization Incentives - Windows, Insulation, Duct Sealing, etc.	√	√	√	√	√	√
New Homes	√	√	√	√	√	√
Low-Income Weatherization	√	√	√	√	√	√
Home Energy Reports		√	√	√	√	√
School Curriculum		√	√		√	
Financing Options With On-Bill Payments		√	√			
Trade Ally Outreach	√	√	√	√	√	√

Program Services & Offerings by Sector and State	California	Oregon	Washington	Idaho	Utah	Wyoming
Non-Residential Sector						
Irrigation Load Control		√	√	√	√	
Commercial and Industrial Demand Response		√	√		√	
Standard Incentives	√	√	√	√	√	√
Energy Engineering Services	√	√	√	√	√	√
Billing Credit Incentive (offset to DSM charge)		√			√	√
Energy Management	√	√	√	√	√	√
Energy Profiler Online	√	√	√	√	√	√
Business Solutions Toolkit	√	√	√	√	√	√
Trade Ally Outreach	√	√	√	√	√	√
Small Business Lighting		√	√	√	√	√
Lighting Instant Incentives	√	√	√	√	√	√
Small to Mid-Sized Business Facilitation	√	√	√	√	√	√
DSM Project Managers Partner With Customer Account Managers	√	√	√	√	√	√

Table D.2 – Current Wattsmart Outreach and Communications Activities

Wattsmart Outreach & Communications (incremental to program specific advertising)	California	Oregon	Washington	Idaho	Utah	Wyoming
Advertising		√	√	√	√	√
Sponsorships		√			√	
Social Media	√	√	√	√	√	√
Public Relations	√	√	√		√	√
Business Advocacy (awards at customer meetings, sponsorships, chamber partnership, university partnership)	√	√	√	√	√	√
Wattsmart Workshops and Community Outreach	√	√	√	√	√	√
BE *watt**smart***, Begin at Home - in school energy education			√	√	√	√

State-Specific DSM Planning Processes

A summary of the DSM planning process in each state is provided below.

Utah, Wyoming and Idaho

The company's biennial IRP and associated action plan provides the foundation for DSM acquisition targets in each state. Where appropriate, the company maintains and uses external stakeholder groups and vendors to advise on a range of issues including annual goals for conservation programs, development of conservation potential assessments, development of multi-year DSM plans, program marketing, incentive levels, budgets, adaptive management, and the development of new and pilot programs.

Washington

The company is one of three investor-owned utilities required to comply with the Energy Independence Act (also referred to as I-937) approved in November 2006. The Act requires utilities to pursue all conservation that is cost-effective, reliable, and feasible. Every two years, each utility must identify its 10-year conservation potential and two-year acquisition target based on its IRP and using methodologies that are consistent with those used by the Northwest Power and Conservation Council. Each utility must maintain and use an external conservation stakeholder group that advises on a wide range of issues including conservation programs, development of conservation potential assessments, program marketing, incentive levels, budgets, adaptive management, and the development of new and pilot programs. PacifiCorp works with the conservation stakeholder group annually on its energy efficiency program design and planning.

In 2019, Washington passed the Clean Energy Transformation Act (CETA), which requires utilities to meet three primary clean energy standards: remove coal-fueled generation from Washington's allocation of electricity by 2025, serve Washington customers with greenhouse gas neutral electricity by 2030, and to serve customers in Washington with 100% renewable and non-emitting electricity by 2045. The conservation stakeholder group and the demand-side management advisory group inform the CETA planning process as documented in the Company's Clean Energy Implementation Plan (CEIP)[4].

California

On December 19, 2022, the Commission issued approved the company's Biennial Budget Advice Letter (BBAL) Filing 697E to administering its energy efficiency programs through 2024. The BBAL was submitted PacifiCorp submitted in accordance with Ordering Paragraph 4 of Decision (D.) 21-12-034 an application for the continuation of energy efficiency programs for program years 2022-2026 on December 31, 2020.

Oregon

Energy efficiency programs for Oregon customers are planned for and delivered by Energy Trust of Oregon in collaboration with PacifiCorp. Energy Trust's planning process is comparable to PacifiCorp's other states, including establishing resource acquisition targets based on resource assessment and integrated resource planning, developing programs based on local market conditions, and coordinating with stakeholders and regulators to ensure efficient and cost-effective delivery of energy efficiency resources.

Preferred Portfolio DSM Resource Selections

The following tables show the economic DSM resource selections by state and year in the 2023 IRP preferred portfolio[5].

[4] The Company's CEIP can be found online at https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/ceip/PAC-CEIP-12-30-21_with_Appx.pdf

[5] Following DSM resource selection methodologies described in Chapter 7 of the IRP.

Table D.3 –First Year Demand Response Resource Selections (2023 IRP Preferred Portfolio)[6]

Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
DR Summer - ID	0.0	0.0	4.1	9.0	5.7	1.0	0.3	0.3	0.3	0.0
DR Summer - UT	0.0	8.5	27.6	23.3	28.7	20.6	12.1	10.6	13.9	0.0
DR Summer - WY	0.0	0.0	14.3	0.9	21.8	3.5	0.1	0.0	0.1	0.0
DR Winter - ID	0.0	0.4	1.0	1.1	0.6	0.2	0.0	0.0	0.0	0.0
DR Winter - UT	0.0	0.5	6.7	5.6	1.7	1.9	0.0	0.0	0.0	0.0
DR Winter - WY	0.0	0.0	9.8	14.3	7.3	4.3	0.4	0.5	0.3	0.0
DR Summer - CA	0.0	0.0	2.7	1.5	1.4	0.5	0.1	0.1	0.2	0.0
DR Summer - OR	47.0	1.9	33.5	20.6	44.6	16.0	12.3	4.0	5.5	0.0
DR Summer - WA	24.5	2.9	7.3	7.5	10.7	3.7	2.0	0.0	1.8	0.0
DR Winter - CA	0.0	0.0	1.2	1.7	0.3	1.1	0.0	0.0	0.0	0.0
DR Winter - OR	0.0	14.7	37.0	20.2	9.0	23.3	0.0	0.0	0.0	0.0
DR Winter - WA	0.0	9.7	7.1	3.6	1.2	5.1	0.0	0.0	0.0	0.0
Resource	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
DR Summer - ID	-	-	-	-	-	37.3	0.4	0.3	-	-
DR Summer - UT	-	-	-	-	-	113.2	14.8	15.5	-	-
DR Summer - WY	-	-	-	-	-	7.4	0.1	0.1	-	-
DR Winter - ID	-	-	-	-	-	-	-	-	-	-
DR Winter - UT	-	-	-	-	-	-	-	-	-	-
DR Winter - WY	-	-	-	-	-	0.4	-	-	-	-
DR Summer - CA	-	-	0.2	0.0	-	3.8	0.1	0.1	-	-
DR Summer - OR	-	-	3.6	0.0	0.0	57.3	3.3	3.0	-	-
DR Summer - WA	-	-	0.8	-	-	13.2	0.7	0.5	-	-
DR Winter - CA	-	-	-	-	-	-	-	-	-	-
DR Winter - OR	-	-	-	-	-	-	-	-	-	-
DR Winter - WA	-	-	2.4	-	-	-	-	-	-	-

Table D.4 – First Year Energy Efficiency Resource Selections (2023 IRP Preferred Portfolio)

Energy Efficiency Energy (1st Year Savings MWh) Selected by State and Year										
State	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
CA	2,425	2,704	3,033	3,503	4,200	4,703	4,540	3,623	4,292	3,093
OR	164,891	188,547	198,401	157,042	169,924	165,387	128,721	138,568	187,201	96,943
WA	53,112	39,612	48,328	32,771	37,248	41,527	41,936	42,014	42,060	38,434
UT	266,500	266,661	273,564	292,860	318,621	348,920	421,605	434,966	722,976	286,797
ID	12,000	14,884	17,573	21,828	24,912	26,756	28,528	28,069	34,929	22,065
WY	44,204	38,468	55,003	55,087	58,854	59,351	66,738	69,934	93,500	61,036
Total System	543,132	550,876	595,902	563,091	613,759	646,644	692,068	717,174	1,084,958	508,368

Energy Efficiency Energy (1st Year Savings MWh) Selected by State and Year										
State	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
CA	2,968	2,941	2,712	4,291	5,027	4,365	3,931	3,088	1,045	1,369
OR	113,012	116,620	70,673	89,040	157,073	85,104	84,261	58,890	31,439	150,622
WA	37,560	36,741	35,895	35,228	35,735	30,881	27,574	27,252	17,639	16,641
UT	324,918	335,953	351,377	486,426	753,213	307,927	344,013	376,481	382,259	513,035
ID	26,134	28,410	29,288	30,150	29,760	23,177	21,277	22,636	20,693	17,551
WY	59,034	61,187	59,279	81,096	74,415	50,116	46,386	54,210	39,728	68,544
Total System	563,626	581,852	549,224	726,231	1,055,223	501,570	527,442	542,557	492,803	767,762

For the 20-year assumed nameplate capacity contributions (MW impacts) by state and year associated with the energy efficiency resource selections above, see Volume I, Chapter 9 (Modeling and Portfolio Selection).

[6] A portion of cost-effective demand response resources identified in the 2023 preferred portfolio in 2023 for Oregon and Washington represent planned volumes expected to be acquired in 2023 PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources offered through approved programs.

APPENDIX E – SMART GRID

Introduction

Smart grid is the application of advanced communications and controls to the electric power system. As such, a wide array of applications can be defined under the smart grid umbrella. PacifiCorp has identified specific areas for research that include technologies such as dynamic line rating, phasor measurement units, distribution automation, advanced metering infrastructure (AMI), automated demand response and other advanced technologies. PacifiCorp has reviewed relevant smart grid technologies for transmission and distribution systems that provide local and system benefits. When considering these technologies, advanced controls and communications often the most critical infrastructure decision. This network must have relevant speed, reliability, and security to support applications such as current real-time WEIM (optimizes the energy imbalances throughout the West) by transferring energy between participants in 15-minute and 5-minute intervals throughout the day.

PacifiCorp has planned to build on the success of real-time energy market innovation by joining the new Western day-ahead market, (EDAM), developed by the California Independent System Operator (CAISO). A modernized western energy market is a key component of PacifiCorp's strategy to connect and optimize the West's abundant and diverse energy resources to deliver the lowest cost and most reliable pathway to a net-zero energy future. PacifiCorp is committed to advancing innovation in markets and new energy technologies to meet its commitment to affordability and reliability while supporting its communities throughout the energy transition.

PacifiCorp has focused on those technologies that present a positive benefit for customers and has implemented functions such as advanced metering, dynamic line rating, and distribution automation. This will optimize the electrical grid when and where it is economically feasible, operationally beneficial and in the best interest of customers. PacifiCorp is committed to consistently evaluating the value of emerging technologies for integration when they are found to be appropriate investments. The company is working with state commissions to improve reliability, energy efficiency, customer service, and integration of renewable resources by analyzing the total cost of ownership, performing thorough cost-benefit analyses, and reaching out to customers concerning smart grid applications and technologies. As technology advances and development continues, PacifiCorp can improve cost estimates and benefits of smart grid technologies that will assist in identifying the best suited technologies for implementation.

Transmission Network and Operation Enhancements

Dynamic Line Rating

Dynamic line rating is the application of sensors to transmission lines to indicate the real-time current-carrying capacity of the lines in relation to thermal restrictions. Transmission line ratings are typically based online-loading calculations given a set of worst-case weather assumptions, such as high ambient temperatures and very low wind speeds. Dynamic line rating (DLR) allows an increase in current-carrying capacity of transmission lines, when more favorable weather conditions are present, a without compromising safety. DLR has become increasingly relevant with higher shares of variable renewable energy (VRE) in the power system. By seeking to increase the ampacity of transmission lines, it provides economic and technical benefits to all involved. FERC NOPR (RM21-17-000) is calling to fully consider dynamic line ratings and advanced power flow control devices in local and regional transmission planning processes.

PacifiCorp has been using DLR since 2014. The Standpipe-Platte project was implemented in 2014 and has delivered positive results as windy days are directly linked to increased wind power generation and increased transmission ratings. A dynamic line rating system is used to determine the resulting cooling effect of the wind on the line. The current carrying capacity is then updated to a new weather dependent line rating. The Standpipe-Platte 230 kilovolt (kV) transmission line is one of three lines in the Aeolus West transmission corridor and had been one of the lines that limits the corridor power transfer. As a result of this project, the Aeolus West Western Electricity Coordinating Council (WECC) non-simultaneous path rating was increased. The DLR system on the Platte – Standpipe 230 kV line has been updated with a Transmission Line Monitoring (TLM) system manufactured by Lindsey Systems.

Additionally, a new DLR system is being implemented on the existing Dave Johnston- Amasa – Difficulty – Shirley Basin 230 kV line as part of the Gateway Segment D.1 Project. The Dave Johnston- Amasa – Difficulty – Shirley Basin 230 kV line connects two areas with a high penetration of wind generation resources and implementation of the DLR system will improve the link between those two areas to reduce the need for operational curtailments when wind patterns result in a variation in generation between the two areas, such as high winds in the northeast area and moderate to low winds in the southeast area. The DLR system will increase the transmission line steady-state rating under increased wind conditions and reduce instances and duration of associated generation curtailments.

Dynamic line rating will be considered for all future transmission needs as a means for increasing capacity in relation to traditional construction methods. Dynamic line rating is only applicable for thermal constraints and only provides additional site-dependent capacity during finite time periods, and it may or may not align with expected transmission needs of future projects. PacifiCorp will continue to look for opportunities to cost-effectively employ dynamic line rating systems similarly to the one deployed on the Standpipe – Platte 230 kV transmission line...

Digital Fault Recorders / Phasor Measurement Unit Deployment

To meet compliance with the North American Electric Reliability Corporation (NERC) MOD-033-1 and PRC-002-2 standards, PacifiCorp has installed over 100 multifunctional digital fault recorders (DFR) which include phasor measurement unit (PMU) functionality. The installations are at key transmission and generation facilities throughout the six-state service territory, generally placed on WECC identified critical paths. PMUs provide sub-second data for voltage and current phasors, which can be used for MOD-033-1 event analysis and model verification. DFRs have a shorter recording time with higher sampling rate to validate dynamic disturbance modelling per PRC-002-2. The DFR/PMUs will deliver dynamic PMU data to a centralized phasor data concentrator (PDC) storage server where offline analysis can be performed by transmission operators, planners, and protection engineers to validate system models has been completed.

Transmission planners will use the phasor data quantities from actual system events to benchmark performance of steady-state and transient stability models of the interconnected transmission system and generating facilities. Using a combination of phasor data from the PMUs and analog quantities currently available through Supervisory Control and Data Acquisition System (SCADA), transmission planners can set up the system models to accurately depict the transmission system prior to, during, and following an event. Differences in simulated versus actual system performance will then be evaluated to allow for enhancements and corrections to the system model.

Model validation procedures are being evaluated, in conjunction with data and equipment availability to fulfill MOD-033-1. The process of validating the system model against a historical system outage event that includes the comparison of a planning power flow model to actual system behavior and the comparison of the planning dynamic model to actual system response is ongoing.

PacifiCorp will continually evaluate potential benefits of PMU installation and intelligent monitoring as the industry considers PMU in special protection, remedial action scheme and other roles that support transmission grid operators. PacifiCorp will continue to work with the California Independent System Operator's (CAISO) Reliability Coordinator West to share data as appropriate.

Distribution Automation and Reliability

Distribution Automation

Distribution automation encompasses a wide field of smart grid technology and applications that focus on using sensors and data collection on the distribution system, as well as automatically adjusting the system to optimize performance. Distribution automation can also provide improved outage management with decreased restoration times after failure, operational efficiency, and peak load management using distributed resources and predictive equipment failure analysis using complex data algorithms. PacifiCorp is working on distribution automation initiatives focused on improved system reliability through improved outage management and response.

In Oregon, PacifiCorp identified 40 circuits on which cost benefit analyses were performed. From this analysis two circuits in Lincoln City, Oregon were selected to have a fault location, isolation and service restoration (FLISR) system installed. The project was installed through 2019 and commissioning of the automation scheme conducted through 2020 in the distribution loop out of Devil's Lake substation in Lincoln City, Oregon. The Company also moved its pre-deployment distribution automation testing equipment to its Tech Ops center in Portland, Oregon to expand open discussion between internal end users including operations, service crews and field technicians. Throughout the implementation of the Devil's Lake DA scheme, the Company faced persistent challenges with communication over its existing AMI network. The Company found the communication capability of AMI was not suited well for a FLISR scheme and evaluated alternative solutions. The solution now uses fiber optic communication, which the Company installed in a loop configuration to increase resiliency of the FLISR scheme's communication path. The fiber infrastructure was deployed in Q4 2022, and the Company now has complete FLISR capability with the Devil's Lake DA system.

Based on that experience additional two additional automation projects were initiated in Portland and Medford, relying on private fiber optic communications (in a manner very similar to how transmission assets would be monitored) Engineering and construction are in progress and commissioning during 2022 is anticipated.

Distribution Substation Metering

Substation monitoring and measurement of various electrical attributes were identified as a necessity due to the increasing complexity of distribution planning driven by growing levels of primarily solar generation as distributed energy resources. Enhanced measurements improve visibility into loading levels and generation hosting capacity as well as load shapes, customer usage patterns, and information about reliability and power quality events.

In 2017, an advanced substation metering project was initiated to provide an affordable option for gathering required substation and circuit data at locations where SCADA is unavailable and/or uneconomical. SCADA has been the preferred form of gathering load profile data from distribution circuits, however SCADA systems can be expensive to install, and additional equipment is required to provide the data needed to perform distribution system and power quality analysis. When system data rather than data and control is important, SCADA is no longer the best option.

Engineers require data to perform analysis of system loading and diagnose waveform and harmonics issues; the lack of data can inhibit accurate system evaluations. The substation metering project recognizes that system data has value independent of control and current system status. The advanced substation metering pilot is intended to provide an affordable option for gathering required distribution system data.

The advanced substation metering project was intended to provide an affordable option for gathering required distribution system data. The Company's work plan included:

- Finalize installation of advanced substation meters at distribution substations and document installations
- Ensure all substation meters installed as part of this program are enabled with remote communication capabilities
- Refine a data management system (PQView) to automatically download, analyze and interpret data downloaded from all installed substation meters

The advanced substation metering project enabled installation of enhanced monitors at more than fifty distribution circuits in the state of Utah. The Company also deployed PQView software, a data analytics tool that provides users with a refined view of power quality information gathered from substation meters.

Distributed Energy Resources

Energy Storage Systems

In 2017, PacifiCorp filed the Energy Storage Potential Evaluation and Energy Storage Project proposal with the Public Utilities Commission or Oregon. This filing was in alignment with PacifiCorp's strategy and vision regarding the expansion and integration of renewable technologies. The company proposed a utility-owned targeted energy storage system (ESS) pilot project. In 2019 PacifiCorp began project development and is progressing to build an ESS on a Hillview substation distribution circuit in Corvallis, Oregon. Due to issues finding a suitable location in Corvallis the company located a different location. The new location for the ESS is the Lakeport Substation in Klamath Falls. The intent of this project is to integrate the ESS into the existing distribution system with the capability and flexibility to potentially advance to a future micro grid system.

Phase I of the project involves/involved installation of a single, utility-owned energy storage device to address historic outage characterization on a specific feeder, validate modeling through field test data, create a research platform and optimize energy storage controls and integration on the Company network. The Company contracted an owner's engineer to aid in project development and is progressing on the Phase I project to build an ESS at the Oregon Institute of Technology

(OIT) on circuit SL49, fed from the Lakeport substation. The Company contracted Powin Energy to provide the ESS. The intent of this project is to integrate the ESS into the existing distribution system with the capability and flexibility to potentially provide renewables integration support with OIT's solar generation. The minimum system size is:

- Energy requirement of 6 MWh
- Power requirement of 2 MW

Phase II of the project involves/involved the addition of an additional energy storage device to pilot distributed storage, optimize use cases per Phase I results, explore tariff structure and ownership models and continue research.

In 2020, PacifiCorp developed Community Resiliency programs in Oregon and California to expand customer and utility understanding of how the use of ESS equipment might increase the resilience of critical facilities. The initial pilot programs provided technical support and evaluation of potential options as well as grant funding for on-site battery storage systems. Over one dozen feasibility studies have been delivered across the service territory of the two states. Two ESS systems have been installed in California with a third approved; two grant submissions in Oregon are in the final stage of application approval. As part of the Company's forthcoming first Clean Energy Plan (CEP) with the Oregon Public Utilities Commission. PacifiCorp presented a strawman proposal to expand the Oregon pilot into a larger program that could provide grant funding for the installation of solar as well as battery storage. The Program would continue to provide feasibility studies and technical support to interested facilities. The Company plans to elicit feedback on the proposal through CEP stakeholder channels and determine next steps by the end of 2023.

The PacifiCorp filing with FERC covering optional generation interconnection study assumptions for stand-alone electric storage resources was approved on February 28, 2023 (section 38.1 of the Open Access Transmission Tariff). The use of real-world operating assumptions for electric storage resources should lead to a more efficient interconnection process.

Demand Response

In 2018, PacifiCorp transitioned to the automatic dispatch of the residential air conditioner (A/C) program in Utah, utilizing two-way communication devices to respond to frequency dispatch signals. Known as Cool Keeper this frequency dispatch innovation is a grid-scale solution using fast-acting residential demand response resources to support the bulk power system. Some utilities use generating resources to perform this function, but as higher levels of wind and solar resources are added, additional balancing resources are required. The Cool Keeper system provides over 200 MWs of operating reserves to the system through the control of more than 108,000 A/C units.

In 2021, PacifiCorp released a Request for Proposals for Demand Response resources. The Company has used the responses to incorporate the cost of Demand Response programs more accurately in the 2021 Integrated Resource Plan. In 2022 and 2023, PacifiCorp contracted with vendors solicited during the demand response RFP and filed for programs in Oregon, Washington, Idaho, Utah, and Wyoming. These programs included new Irrigation and Commercial and Industrial curtailment programs.

Dispatchable Customer Storage Resources

Based on the learnings from Rocky Mountain Power's partnership with Soleil Lofts and Sonnen in 2018, the company developed the Wattsmart Battery Program which was approved in Utah October 2020 and in Idaho April 2022. This innovative demand response program allows the

Company to manager behind the meter customer batteries for daily load cycling, backup power real time grid needs such as peak load management, contingency reserves, and frequency response. Customer controlled batteries will allow the company to maximize renewable energy when it's needed to support the electrical gird. The program is experiencing exponential growth and has over 2,700 residential batteries and 8 commercial batteries participating as of Q1 2023.

Advanced Metering Infrastructure

Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that provide interval data available daily. This infrastructure can also provide advanced functionalities including remote connect/disconnect, outage detection and restoration signals, and support distribution automation schemes. In 2016, PacifiCorp identified economical AMI solutions for California and Oregon that delivered tangible benefits to customers while minimizing the impact on consumer rates.

In 2019, PacifiCorp completed installation of the Itron Gen5 AMI system across the Company's Oregon and California service territories. The AMI system consists of head-end software, FANs and approximately 656,000 meters. Interval energy usage data is provided to customers via the Pacific Power website and mobile app. The project was completed on schedule and on budget.

In 2018, PacifiCorp awarded a contract to Itron for their OpenWay Riva AMI system in the states of Idaho and Utah. In early 2020, Itron proposed a change for the information technology (IT) and network systems, using their Gen5 system rather than the OpenWay system, while still deploying the more advanced Riva meter technology. Itron's Gen5 system has the same IT and network used in PacifiCorp's Oregon and California service territories. This solution aligns with Itron's future road map and provides PacifiCorp with a single operational system that will reduce cybersecurity issues and operating costs associated with maintaining separate systems. This solution provides a stronger, more flexible network coupled with a high-end metering solution.

The Utah/Idaho project involves upgrading the head-end software and installation of the Field Area Network (FAN) and approximately 240,000 new Itron Riva AMI meters for most customer classification and 20,000 Aclara AMI meters for the Utah rate schedule 136 private generation accounts. This solution will utilize over 80% of the existing AMR meters in Utah to provide hourly interval data for residential customers as well as outage detection and restoration messaging. The project will replace all current meters in Idaho with new Itron Riva AMI meters as AMR was not fully deployed there. Furthermore, the project will leverage the customer communication tools developed for the Oregon and California AMI projects.

Meter and FAN system installations in Idaho are substantially complete. Utah FAN and meter installations are underway with completion scheduled for Q4 2023. Costs and benefits associated with the AMI project will be tracked and analyzed and will be evaluated against the business case projections after completion.

Financial analyses to extend AMI solutions to Washington and Wyoming were performed in 2019 and 2020, respectively. The analyses determined that moving these states to an AMI solution was not cost effective at this time. The Company is currently updating the business case for both states. The review should be completed by Q2 2023.

Financial analyses to extend AMI solutions to Washington and Wyoming were performed in 2019 and 2020, respectively. These states utilize the same AMR meter technology as Utah and can be leveraged to provide extended functionality and value. The analyses determined that moving these states to an AMI solution is not cost effective at this time but has improved slightly over previous analyses. The Company will continue to review and evaluate the business case and cost effectiveness for these states routinely over the next few years.

Outage Management Improvements

PacifiCorp advanced a new module in its OMS which allows for field responders to update outage data as they complete their work, using Mobile Workforce Management tools; this functionality is restricted to service transformer and customer meter devices, which comprise approximately half of the outages to which the company responds. This ensures more rapid, accurate and efficient updates to outage data, but still maintains the OMS topology as the method to manage line worker safety by having real-time access to elements that are energized and those which may be in an abnormal state.

Meter pinging and last-gasp outage management functionalities were put in place for the AMI system in Oregon and California. The same outage management systems (OMS) will be used for Utah and Idaho when those projects are complete. Company’s system operations organization has begun using meter ping functionality and last-gasp messages to augment customer calls and create outage tickets in the Company’s OMS. The Company implemented business process changes to facilitate outage management functionality for single service as well as large-scale outages. These changes have provided the system operations with more flexibility to identify and respond to outages.

The intelligent line sensors will be installed on distribution circuits that will provide service to critical facilities. For this project, critical facilities have been defined as major emergency facility centers such as hospitals, trauma centers, police, and fire dispatch centers, etc. The information provided by the line sensors will allow control center operators to target restoration at critical facilities during major outages sooner than is currently possible. Full implementation of the project is was completed in December 2021, concurrent with the completion of the AMI project.

Future Smart Grid

The Company continues to develop a strategy to attain long-term goals for grid modernization and smart grid-related activities to continually improve system efficiency, reliability, and safety, while providing a cost-effective service to our customers. The Company will continue to monitor smart grid technologies and determine viability and applicability of implementation to the system, and as tipping points to broader implementation occur it’s expected these will be communicated through a variety of methods, including this IRP as well as other regulatory mechanisms relevant to that state.

APPENDIX F – FLEXIBLE RESERVE STUDY

Introduction

While PacifiCorp had significant increases in both wind and solar capacity on its system in 2021, there has not yet been time to collect and assess sufficient historical data that includes this expanded output. Therefore, for the 2023 IRP, PacifiCorp is continuing to use the methodology developed in its 2021 Flexible Reserve Study (FRS), which relied upon historical data from 2018-2019, as discussed below.[1]

The 2021 Flexible Reserve Study (FRS) estimated the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards. Because the FRS methodology accounts for changes in PacifiCorp's resource mix, both the quantity and cost of reserves has been updated for the 2023 IRP, as reported herein.

PacifiCorp operates two balancing authority areas (BAAs) in the Western Electricity Coordinating Council (WECC) NERC region--PacifiCorp East (PACE) and PacifiCorp West (PACW). The PACE and PACW BAAs are interconnected by a limited amount of transmission across a third-party transmission system and the two BAAs are each required to comply with NERC standards. PacifiCorp must provide sufficient regulation reserve to remain within NERC's balancing authority area control error (ACE) limit in compliance with BAL-001-2,[2] as well as the amount of contingency reserve required to comply with NERC standard BAL-002-WECC-2.[3] BAL-001-2 is a regulation reserve standard that became effective July 1, 2016, and BAL-002-WECC-3 is a contingency reserve standard that became effective June 28, 2021. Regulation reserve and contingency reserve are components of operating reserve, which NERC defines as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."[4]

Apart from disturbance events that are addressed through contingency reserve, regulation reserve is necessary to compensate for changes in load demand and generation output to maintain ACE within mandatory parameters established by the BAL-001-2 standard. The FRS estimates the amount of regulation reserve required to manage variations in load, variable energy resources[5]

[1] 2021 IRP Volume II, Appendix F (Flexible Reserve Study): https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20II%20-%209.15.2021%20Final.pdf

[2] NERC Standard BAL-001-2, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf, which became effective July 1, 2016. ACE is the difference between a BAA's scheduled and actual interchange and reflects the difference between electrical generation and Load within that BAA.

[3] NERC Standard BAL-002-WECC-3, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf, which became effective June 28, 2021. BAL-002-WECC-3 removed the requirement that at least 50% of contingency reserves be held as "spinning" resources, as this was deemed redundant with frequency response requirements under BAL-003-2.

[4] Glossary of Terms Used in NERC Reliability Standards: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf, updated March 8, 2023.

[5] VERs are resources that resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator. *Integration of Variable Energy*

(VERs), and resources that are not VERs ("Non-VERs") in each of PacifiCorp's BAAs. Load, wind, solar, and Non-VERs were each studied because PacifiCorp's data indicates that these components or customer classes place different regulation reserve burdens on PacifiCorp's system due to differences in the magnitude, frequency, and timing of their variations from forecasted levels.

The FRS is based on PacifiCorp operational data recorded from January 2018 through December 2019 for load, wind, solar, and Non-VERs. PacifiCorp's primary analysis focuses on the actual variability of load, wind, solar, and Non-VERs during 2018-2019. A supplemental analysis discusses how the total variability of the PacifiCorp system changes with varying levels of wind and solar capacity. The estimated regulation reserve amounts determined in this study represent the incremental capacity needed to ensure compliance with BAL-001-2 for a particular operating hour. The regulation reserve requirement covers variations in load, wind, solar, and Non-VERs, while implicitly accounting for the diversity between the different classes. An explicit adjustment is also made to account for diversity benefits realized because of PacifiCorp's participation in the Energy Imbalance Market (EIM) operated by the California Independent System Operator Corporation (CAISO).

The methodology in the FRS is like that employed in PacifiCorp's 2019 IRP but has been enhanced in two areas.[6] First, the historical period evaluated in the study has been expanded to include two years, rather than one, to capture a larger sample of system conditions. Second, the methodology for extrapolating results for higher renewable resource penetration levels has been modified to better capture the diversity between growing wind and solar portfolios.

The FRS results produce an hourly forecast of the regulation reserve requirements for each of PacifiCorp's BAAs that is sufficient to ensure the reliability of the transmission system and compliance with NERC and WECC standards. This regulation reserve forecast covers the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system and varies as a function of the wind and solar capacity on PacifiCorp's system, as well as forecasted levels of wind, solar and load.

The regulation reserve requirement methodologies produced by the FRS are applied in production cost modeling to determine the cost of the reserve requirements associated with incremental wind and solar capacity. After a portfolio is selected, the regulation reserve requirements specific to that portfolio can be calculated and included in the study inputs, such that the production cost impact of the requirements is incorporated in the reported results. As a result, this production cost impact is dependent on the wind and solar resources in the portfolio as well as the characteristics of the dispatchable resources in the portfolio that are available to provide regulation reserves.

Resources, Order No. 764, 139 FERC ¶ 61,246 at P 281 (2012) ("Order No. 764"); *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"); *order on reh'g and clarification*, Order No. 764-B, 144 FERC ¶ 61,222 at P 210 (2013) ("Order No. 764-B").

[6] 2019 IRP Volume II, Appendix F (Flexible Reserve Study): https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_A-L.pdf

Overview

The primary analysis in the FRS is to estimate the regulation reserve necessary to maintain compliance with NERC Standard BAL-001-2 given a specified portfolio of wind and solar resources. The FRS next calculates the cost of holding regulation reserve for incremental wind and solar resources. Finally, the FRS compares PacifiCorp's overall operating reserve requirements over the IRP study period, including both regulation reserve and contingency reserve, to its flexible resource supply.

The FRS estimates regulation reserve based on the specific requirements of NERC Standard BAL-001-2. It also incorporates the current timeline for EIM market processes, as well as EIM resource deviations and diversity benefits based on actual results. The FRS also includes adjustments to regulation reserve requirements to account for the changing portfolio of solar and wind resources on PacifiCorp's system and accounts for the diversity of using a single portfolio of regulation reserve resources to cover variations in load, wind, solar, and Non-VERs. A comparison of the results of the current analysis and that from previous IRPs is shown in Table F.1 and Table F.2. Flexible resource costs are portfolio dependent and vary over time. For more details, please refer to Figure F.11 – Incremental Wind and Solar Regulation Reserve Costs.

Table F.1 - Portfolio Regulation Reserve Requirements

Case	Wind Capacity (MW)	Solar Capacity MW	Stand-alone Regulation Requirement (MW)	Portfolio Diversity Credit (%)	Regulation Requirement with Diversity (MW)
CY2017 (2019 FRS)	2,750	1,021	994	47%	531
2018-2019 (2021 FRS)	2,745	1,080	1,057	49%	540

Table F.2 - 2023 Flexible Resource Costs as Compared to 2021 Costs, $/MWh

	Wind 2023 FRS (2022$)	Solar 2023 FRS (2022$)	Wind 2021 FRS (2022$)	Solar 2021 FRS (2022$)
Study Period	2025-2042	2025-2042	2023-2040	2023-2040
Flexible Resource Cost	$1.38	$1.59	$1.58	$1.32

Flexible Resource Requirements

PacifiCorp's flexible resource needs are the same as its operating reserve requirements over the planning horizon for maintaining reliability and compliance with NERC regional reliability standards. Operating reserve generally consists of three categories: (1) contingency reserve (i.e., spinning, and supplemental reserve), (2) regulation reserve, and (3) frequency response reserve. Contingency reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC regional reliability standard BAL-002-WECC-3.[7] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in

[7] NERC Standard BAL-002-WECC-3 – Contingency Reserve:
https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-WECC-3.pdf

BAL-001-2.[8] Frequency response reserve is capacity that PacifiCorp holds available to ensure compliance with NERC standard BAL-003-2.[9] Each type of operating reserve is further defined below.

Contingency Reserve

Purpose: Contingency reserve may be deployed when unexpected outages of a generator or a transmission line occur. Contingency reserve may not be deployed to manage other system fluctuations such as changes in load or wind generation output.

Volume: NERC regional reliability standard BAL-002-WECC-3 specifies that each BAA must hold as contingency reserve an amount of capacity equal to three percent of load and three percent of generation in that BAA.

Duration: Except within 60 minutes of a qualifying contingency event, a BAA must maintain the required level of contingency reserve at all times. Generally, this means that up to 60 minutes of generation are required to provide contingency reserve, though successive outage events may result in contingency reserves being deployed for longer periods. To restore contingency reserves, other resources must be deployed to replace any generating resources that experienced outages, typically either market purchases or generation from resources with slower ramp rates.

Ramp Rate: Only up capacity available within ten minutes can be counted as contingency reserve. This can include "spinning" resources that are online and immediately responsive to system frequency deviations to maintain compliance with frequency response obligations under BAL-003-1.1, as well as from "non-spinning" resources that do not respond immediately, though they must still be fully deployed in ten minutes.[10]

Regulation Reserve

Purpose: NERC standard BAL-001-2, which became effective July 1, 2016, does not specify a regulation reserve requirement based on a simple formula, but instead requires utilities to hold sufficient reserve to meet specified control performance standards. The primary requirement relates to area control error ("ACE"), which is the difference between a BAA's scheduled and actual interchange and reflects the difference between electrical generation and load within that BAA. Requirement 2 of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…*

[8] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf
[9] NERC Standard BAL-003-2 — Frequency Response and Frequency Bias Setting: https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-2.pdf
[10] While the minimum spinning reserve obligation previously contained within BAL-002-WECC-2a was retired due to redundancy with frequency response obligations under BAL-003-2, PacifiCorp's 2023 IRP does not explicitly model the frequency response obligation and retains the spinning obligation to ensure a supply of rapidly responding resources is maintained.

In addition, Requirement 1 of BAL-001-2 specifies that PacifiCorp's Control Performance Standard 1 ("CPS1") score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated monthly, it does not require a response to every ACE event, but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month. Regulation reserve is thus the capacity that PacifiCorp holds available to respond to changes in generation and load to manage ACE within the limits specified in BAL-001-2.

Volume: NERC standard BAL-001-2 does not specify a regulation reserve requirement based on a simple formula, but instead requires utilities to hold sufficient reserve to meet performance standards as discussed above. The FRS estimates the regulation reserve necessary to meet Requirement 2 by compensating for the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system. These regulation reserve requirements are discussed in more detail later in the study.

Ramp Rate: Because Requirement 2 includes a 30-minute time limit for compliance, ramping capability that can be deployed within 30 minutes contributes to meeting PacifiCorp's regulation reserve requirements. The reserve for CPS1 is not expected to be incremental to the need for compliance with Requirement 2 but may require that a subset of resources held for Requirement 2 be able to make frequent rapid changes to manage ACE relative to interconnection frequency.

Duration: PacifiCorp is required to submit balanced load and resource schedules as part of its participation in EIM. PacifiCorp is also required to submit resources with up flexibility and down flexibility to cover uncertainty and expected ramps across the next hour. Because forecasts are submitted prior to the start of an hour, deviations can begin before an hour starts. As a result, a flexible resource might be called upon for the entire hour. To continue providing flexible capacity in the following hour, energy must be available in storage for that hour as well. The likelihood of deploying for two hours or more for reliability compliance (as opposed to economics) is expected to be small.

Frequency Response Reserve

Purpose: NERC standard BAL-003-2 specifies that each BAA must arrest frequency deviations and support the interconnection when frequency drops below the scheduled level. When a frequency drop occurs because of an event, PacifiCorp will deploy resources that increase the net interchange of its BAAs and the flow of generation to the rest of the interconnection.

Volume: When a frequency drop occurs, each BAA is expected to deploy resources that are at least equal to its frequency response obligation. The incremental requirement is based on the size of the frequency drop and the BAA's frequency response obligation, expressed in megawatt (MW)/0.1 Herts (Hz). To comply with the standard, a BAA's median measured frequency response during a sampling of under-frequency events must be equal to or greater than its frequency response obligation. PacifiCorp's 2022 frequency response obligation was 25.3

MW/0.1Hz for PACW, and 63.5 MW/0.1Hz for PACE.[11] PacifiCorp's combined obligation amounts to 88.8 MW for a frequency drop of 0.1 Hz, or 266.4 MW for a frequency drop of 0.3 Hz.

The performance measurement for contingency reserve under the Disturbance Control Standard (BAL-002-3)[12], allows for recovery to the lesser of zero or the ACE value prior to the contingency event, so increasing ACE above zero during a frequency event reduces the additional deployment needed if a contingency event occurs. Because contingency, regulation, and frequency events are all relatively infrequent, they are unlikely to occur simultaneously. Because the frequency response standard is based on median performance during a year, overlapping requirements that reduced PacifiCorp's response during a limited number of frequency events would not impact compliance.

As a result, any available capacity not being used for generation is expected to contribute to meeting PacifiCorp's frequency response obligation, up to the technical capability of each unit, including that designated as contingency or regulation reserves. Frequency response must occur very rapidly, and a generating unit's capability is limited based on the unit's size, governor controls, and available capacity, as well as the size of the frequency drop. As a result, while a few resources could hold a large amount of contingency or regulation reserve, frequency response may need to be spread over a larger number of resources. Additionally, only resources that have active and tuned governor controls as well as outer loop control logic will respond properly to frequency events.

Ramp Rate: Frequency response performance is measured over a period of seconds, amounting to under a minute. Compliance is based on the average response over the course of an event. As a result, a resource that immediately provides its full frequency response capability will provide the greatest contribution. That same resource will contribute a smaller amount if it instead ramps up to its full frequency response capability over the course of a minute or responds after a lag.

Duration: Frequency response events are less than one minute in duration.

Black Start Requirements

Black start service is the ability of a generating unit to start without an outside electrical supply and is necessary to help ensure the reliable restoration of the grid following a blackout. At this time, PACW grid restoration would occur in coordination with Bonneville Power Administration black start resources. The Gadsby combustion turbine resources can support grid restoration in PACE. PacifiCorp has not identified any incremental needs for black start service during the IRP study period.

Ancillary Services Operational Distinctions

In actual operations, PacifiCorp identifies two types of flexible capacity as part of its participation in the EIM. The contingency reserve held on each resource is specifically identified and is not

[11] NERC. BAL-003-2 Frequency Response Obligation Allocation and Minimum Frequency Bias Settings for Operating Year 2022. https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Frequency%20Response%20Standard%20Resources/BA_FRO_Allocations_for_OY2022-document(002).pdf

[12] NERC Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event: https://www.nerc.com/pa/Stand/Reliability Standards/BAL-002-3.pdf

available for economic dispatch within the EIM. Any remaining flexible capacity on participating resources that is not designated as contingency reserve can be economically dispatched in EIM based on its operating cost (i.e. bid) and system requirements and can contribute to meeting regulation reserve obligations. Because of this distinction, resources must either be designated as contingency reserve or as regulation reserve. Contingency events are relatively rare while opportunities to deploy additional regulation reserve in EIM occur frequently. As a result, PacifiCorp typically schedules its lowest-cost flexible resources to serve its load and blocks off capacity on its highest-cost flexible resources to meet its contingency obligations, subject to any ramping limitations at each resource. This leaves resources with moderate costs available for dispatch up by EIM, while lower-cost flexible resources remain available to be dispatched down by EIM.

Regulation Reserve Data Inputs

Overview

This section describes the data used to determine PacifiCorp's regulation reserve requirements. To estimate PacifiCorp's required regulation reserve amount, PacifiCorp must determine the difference between the expected load and resources and actual load and resources. The difference between load and resources is calculated every four seconds and is represented by the ACE. ACE must be maintained within the limits established by BAL-001-2, so PacifiCorp must estimate the amount of regulation reserve that is necessary to maintain ACE within these limits.

To estimate the amount of regulation reserve that will be required in the future, the FRS identifies the scheduled use of the system as compared to the actual use of the system during the study term. For the baseline determination of scheduled use for load and resources, the FRS used hourly base schedules. Hourly base schedules are the power production forecasts used for imbalance settlement in the EIM and represent the best information available concerning the upcoming hour.[13]

The deviation from scheduled use was derived from data provided through participation in the EIM. The deviations of generation resources in EIM were measured on a five-minute basis, so five-minute intervals are used throughout the regulation reserve analysis.

EIM base schedule and deviation data for each wind, solar and Non-VER transaction point were downloaded using the SettleCore application, which is populated with data provided by the CAISO. Since PacifiCorp's implementation of EIM on November 1, 2014, PacifiCorp requires certain operational forecast data from all its transmission customers pursuant to the provisions of Attachment T to PacifiCorp's Federal Energy Regulatory Commission (FERC) approved Open

[13] The CAISO, as the market operator for the EIM, requests base schedules at 75 minutes (T-75) prior to the hour of delivery. PacifiCorp's transmission customers are required to submit base schedules by 77 minutes (T-77) prior to the hour of delivery – two minutes in advance of the EIM Entity deadline. This allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-75 for the entirety of PacifiCorp's two BAAs. The base schedules are due again to CAISO at 55 minutes (T-55) prior to the delivery hour and can be adjusted up until that time by the EIM Entity (i.e., PacifiCorp Grid Operations). PacifiCorp's transmission customers are required to submit updated, final base schedules no later than 57 minutes (T-57) prior to the delivery hour. Again, this allows all transmission customer base schedules enough time to be submitted into the EIM systems before the overall deadline of T-55 for the entirety of PacifiCorp's two BAAs. Base schedules may be finally adjusted again, by the EIM Entity only, at 40 minutes (T-40) prior to the delivery hour in response to CAISO sufficiency tests. T-40 is the base schedule time point used throughout this study.

Access Transmission Tariff (OATT). This includes EIM base schedule data (or forecasts) from all resources included in the EIM network model at transaction points. EIM base schedules are submitted by transmission customers with hourly granularity, and are settled using hourly data for load, and fifteen-minute and five-minute data for resources. A primary function of the EIM is to measure load and resource imbalance (or deviations) as the difference between the hourly base schedule and the actual metered values.

A summary of the data gathered for this analysis is listed below, and a more detailed description of each type of source data is contained in the following subsections.

Source data:

- Load data
    - Five-minute interval actual load
    - Hourly base schedules

- VER data
    - Five-minute interval actual generation
    - Hourly base schedules

- Non-VER data
    - Five-minute interval actual generation
    - Hourly base schedules

Load Data

The load class represents the aggregate firm demand of end users of power from the electric system. While the requirements of individual users vary, there are diurnal and seasonal patterns in aggregated demand. The load class can generally be described to include three components: (1) average load, which is the base load during a particular scheduling period; (2) the trend, or "ramp," during the hour and from hour-to-hour; and (3) the rapid fluctuations in load that depart from the underlying trend. The need for a system response to the second and third components is the function of regulation reserve in order to ensure reliability of the system.

The PACE BAA includes several large industrial loads with unique patterns of demand. Each of these loads is either interruptible at short notice or includes behind the meter generation. Due to their large size, abrupt changes in their demand are magnified for these customers in a manner which is not representative of the aggregated demand of the large number of small customers which make up most PacifiCorp's loads.

In addition, interruptible loads can be curtailed if their deviations are contributing to a resource shortfall. Because of these unique characteristics, these loads are excluded from the FRS. This treatment is consistent with that used in the CAISO load forecast methodology (used for PACE and PACW operations), which also nets these interruptible customer loads out of the PACE BAA.

Actual average load data was collected separately for the PACE and PACW BAAs for each five-minute interval. Load data has not been adjusted for transmission and distribution losses.

Wind and Solar Data

The wind and solar classes include resources that: (1) are renewable; (2) cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator.[14] Wind and solar, in comparison to load, often have larger upward and downward fluctuations in output that impose significant and sometimes unforeseen challenges when attempting to maintain reliability. For example, as recognized by FERC in Order No. 764, "Increasing the relative amount of [VERs] on a system can increase operational uncertainty that the system operator must manage through operating criteria, practices, and procedures, *including the commitment of adequate reserves*."[15] The data included in the FRS for the wind and solar classes include all wind and solar resources in PacifiCorp's BAAs, which includes: (1) third-party resources (OATT or legacy contract transmission customers); (2) PacifiCorp-owned resources; and (3) other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. In total, the FRS study period includes an average of 2,745 megawatts of wind and 1,080 megawatts of solar.

Non-VER Data

The Non-VER class is a mix of thermal and hydroelectric resources and includes all resources which are not VERs, and which do not provide either contingency or regulation reserve. Non-VERs, in contrast to VERs, are often more stable and predictable. Non-VERs are thus easier to plan for and maintain within a reliable operating state. For example, in Order No. 764, FERC suggested that many of its rules were developed with Non-VERs in mind and that such generation "could be scheduled with relative precision."[16]The output of these resources is largely in the control of the resource operator, particularly when considered within the hourly timeframe of the FRS. The deviations by resources in the Non-VER class are thus significantly lower than the deviations by resources in the wind class. The Non-VER class includes third-party resources (OATT or legacy transmission customers); many PacifiCorp-owned resources; and other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. In total, the FRS includes 2,202 megawatts of Non-VERs.

In the FRS, resources that provide contingency or regulation reserve are considered a separate, dispatchable resource class. The dispatchable resource class compensates for deviations resulting from other users of the transmission system in all hours. While non-dispatchable resources may offset deviations in loads and other resources in some hours, they are not in the control of the system operator and contribute to the overall requirement in other hours. Because the dispatchable resource class is a net provider rather than a user of regulation reserve service, its stand-alone regulation reserve requirement is zero (or negative), and its share of the system regulation reserve requirement is also zero. The allocation of regulation reserve requirements and diversity benefits is discussed in more detail later in the study.

[14] Order No. 764 at P 281; Order No. 764-B at P 210.
[15] Order No. 764 at P 20 (emphasis added).
[16] *Id.* at P 92.

Regulation Reserve Data Analysis and Adjustment

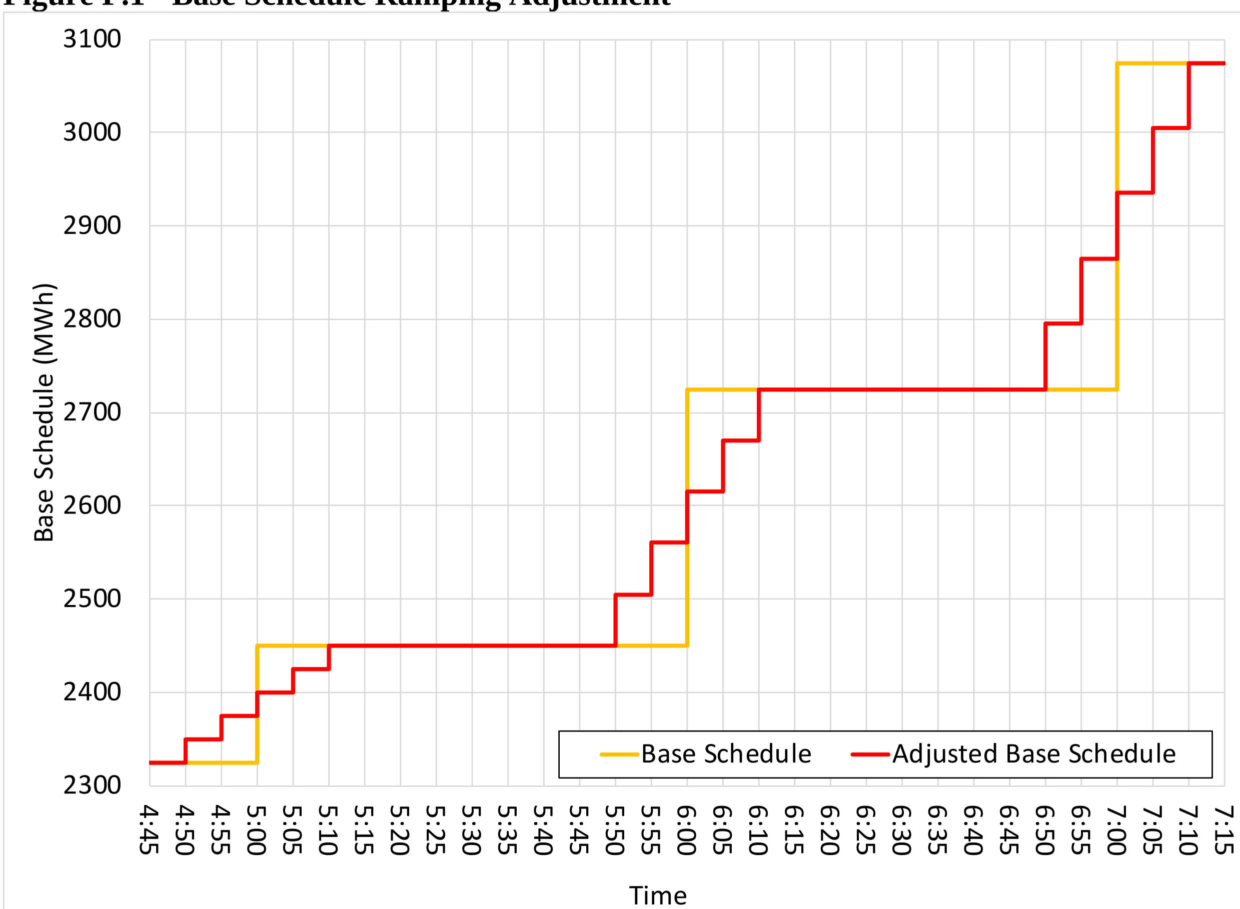
Overview

This section provides details on adjustments made to the data to align the ACE calculation with actual operations, and address data issues.

Base Schedule Ramping Adjustment

In actual operations, PacifiCorp's ACE calculation includes a linear ramp from the base schedule in one hour to the base schedule in the next hour, starting ten-minutes before the hour and continuing until ten-minutes past the hour. The hourly base schedules used in the study are adjusted to reflect this transition from one hour to the next. This adjustment step is important because, to the extent actual load or generation is transitioning to the levels expected in the next hour, the adjusted base schedules will result in reduced deviations during these intervals, potentially reducing the regulation reserve requirement. Figure F.1 below illustrates the hourly base schedule and the ramping adjustment. The same calculation applies to all base schedules: Load, Wind, Non-VERs, and the combined portfolio.

Figure F.1 - Base Schedule Ramping Adjustment



Data Corrections

The data extracted from PacifiCorp's systems for, wind, solar and Non-VERs was sourced from

CAISO settlement quality data. This data has already been verified for inconsistencies as part of the settlement process and needs minimal cleaning as described below. Regarding five-minute interval load data from the PI Ranger system, intervals were excluded from the FRS results if any five-minute interval suffered from at least one of the data anomalies that are described further below:

Load:
- Telemetry spike/poor connection to meter
- Missing meter data
- Missing base schedules

VERs:
- Curtailment events

Load in PacifiCorp's BAAs changes continuously. While a BAA could potentially maintain the exact same load levels in two five-minute intervals in a row, it is extremely unlikely for the exact same load level to persist over longer time frames. When PacifiCorp's energy management system (EMS) load telemetry fails, updated load values may not be logged, and the last available load measurement for the BAA will continue to be reported.

Rapid spikes in load telemetry either up or down are unlikely to be the result of conditions which require deployment of regulation reserve, particularly when they are transient. Such events could be a result of a transmission or distribution outage, which would allow for the deployment of contingency reserve, and would not require deployment of regulation reserve. Such events are also likely to be a result of a single bad load measurement. Load telemetry spike irregularities were identified by examining the intervals with the largest changes from one interval to the next, either up or down. Intervals with inexplicably large and rapid changes in load, particularly where the load reverts within a short period, were assumed to have been covered through contingency reserve deployment or to reflect inaccurate load measurements. Because they do not reflect periods that require regulation reserve deployment, such intervals are excluded from the analysis. During the study period, in PACW 15 minutes' worth of telemetry spikes were excluded while no telemetry spikes were observed in PACE. There were also 10 minutes' worth of missing load meter data, and 82 hours of missing load base schedules.

The available VER data includes wind curtailment events which affect metered output. When these curtailments occur, the CAISO sends data, by generator, indicating the magnitude of the curtailment. This data is layered on top of the actual meter data to develop a proxy for what the metered output would have been if the generator were not curtailed. Regulation reserve requirements are calculated based on the shortfall in actual output relative to base schedules. By adding back curtailed volumes to the actual metered output, the shortfall relative to base schedules is reduced, as is the regulation reserve requirement. This is reasonable since the curtailment is directed by the CAISO or the transmission system operator to help maintain reliable operation, so it should not exacerbate the calculated need for regulation reserves.

After review of the data for each of the above anomaly types, and out of 210,216 five-minute intervals evaluated, approximately 1,000 five-minute intervals, or 0.5% of the data, was removed due to data errors. While cleaning up or replacing anomalous hours could yield a more complete data set, determining the appropriate conditions in those hours would be difficult and subjective.

By removing anomalies, the FRS sample is smaller but remains reflective of the range of conditions PacifiCorp experiences, including the impact on regulation reserve requirements of weather events experienced during the study period.

Regulation Reserve Requirement Methodology

Overview

This section presents the methodology used to determine the initial regulation reserve needed to manage the load and resource balance within PacifiCorp's BAAs. The five-minute interval load and resource deviation data described above informs a regulation reserve forecast methodology that achieves the following goals:

- Complies with NERC standard BAL-001-2;
- Minimizes regulation reserve held; and
- Uses data available at time of EIM base schedule submission at T-40.[17]

The components of the methodology are described below, and include:

- Operating Reserve: Reserve Categories;
- Calculation of Regulation Reserve Need;
- Balancing Authority ACE Limit: Allowed Deviations;
- Planning Reliability Target: Loss of Load Probability ("LOLP"); and
- Regulation Reserve Forecast: Amount Held.

Following the explanation below of the components of the methodology, the next section details the forecasted amount of regulation reserve for:

- Wind;
- Solar;
- Non-VERs; and
- Load.

Components of Operating Reserve Methodology

Operating Reserve: Reserve Categories
Operating reserve consists of three categories: (1) contingency reserve (i.e., spinning and supplemental reserve), (2) regulation reserve, and (3) frequency response reserve. These requirements must be met by resources that are incremental to those needed to meet firm system demand. The purpose of the FRS is to determine the regulation reserve requirement. The contingency reserve and frequency response requirements are defined formulaically by their respective reliability standards.

Of the three categories of reserve referenced above, the FRS is primarily focused on the requirements associated with regulation reserve. Contingency reserve may not be deployed to manage other system fluctuations such as changes in load or wind generation output. Because deviations caused by contingency events are covered by contingency reserve rather than regulation

[17] *See* footnote 12 above for explanation of PacifiCorp's use of the T-40 base schedule time point in the FRS.

reserve, they are excluded from the determination of the regulation reserve requirements. Because frequency response reserve can overlap with that held for contingency and regulation reserve requirements it is similarly excluded from the determination of regulation reserve requirements. The types of operating reserve and relationship between them are further defined in in the Flexible Resource Requirements section above.

Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2, which requires a BAA to carry regulation reserve incremental to contingency reserve to maintain reliability.[18] The regulation reserve requirement is not defined by a simple formula, but instead is the amount of reserve required by each BAA to meet specified control performance standards. Requirement two of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…*

PacifiCorp has been operating under BAL-001-2 since March 1, 2010, as part of a NERC Reliability-Based Control field trial in the Western Interconnection, so PacifiCorp had experience operating under the standard, even before it became effective on July 1, 2016.

The three key elements in BAL-001-2 are: (1) the length of time (or "interval") used to measure compliance; (2) the percentage of intervals that a BAA must be within the limits set in the standard; and (3) the bandwidth of acceptable deviation used under each standard to determine whether an interval is considered out of compliance. These changes are discussed in further detail below.

The first element is the length of time used to measure compliance. Compliance under BAL-001-2 is measured over rolling thirty-minute intervals, with 60 overlapping periods per hour, some of which include parts of two clock-hours. In effect, this means that every minute of every hour is the beginning of a new, thirty-minute compliance interval under the new BAL-001-2 standard. If ACE is within the allowed limits at least once in a thirty-minute interval, that interval is in compliance, so only the minimum deviation in each rolling thirty-minute interval is considered in determining compliance. As a result, PacifiCorp does not need to hold regulation reserve for deviations with duration less than 30 minutes.

The second element is the number of intervals where deviations are allowed to be outside the limits set in the standard. BAL-001-2 requires 100 percent compliance, so deviations must be maintained within the requirement set by the standard for all rolling thirty-minute intervals.

The third element is the bandwidth of acceptable deviation before an interval is considered out of compliance. Under BAL-001-2, the acceptable deviation for each BAA is dynamic, varying as a function of the frequency deviation for the entire interconnect. When interconnection frequency exceeds 60 Hz, the dynamic calculation does not require regulation resources to be deployed regardless of a BAA's ACE. As interconnection frequency drops further below 60 Hz, a BAA's permissible ACE shortfall is increasingly restrictive.

[18] NERC Standard BAL-001-2, https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf

Planning Reliability Target: Loss of Load Probability

When conducting resource planning, it is common to use a reliability target that assumes a specified loss of load probability (LOLP). In effect, this is a plan to curtail firm load in rare circumstances, rather than acquiring resources for extremely unlikely events. The reliability target balances the cost of additional capacity against the benefit of incrementally more reliable operation. By planning to curtail firm load in the rare event of a regulation reserve shortage, PacifiCorp can maintain the required 100 percent compliance with the BAL-001-2 standard and the Balancing Authority ACE Limit. This balances the cost of holding additional regulation reserve against the likelihood of regulation reserve shortage events.

The FRS assumes that a regulation reserve forecasting methodology that results in 0.50 loss of load hours per year due to regulation reserve shortages is appropriate for planning and ratemaking purposes. This is in addition to any loss of load resulting from transmission or distribution outages, resource adequacy, or other causes. The FRS applies this reliability target as follows:

- If the regulation reserve available is greater than the regulation reserve need for an hour, the LOLP is zero for that hour.
- If the regulation reserve held is less than the amount needed, the LOLP is derived from the Balancing Authority ACE Limit probability distribution as illustrated below.

Balancing Authority ACE Limit: Allowed Deviations

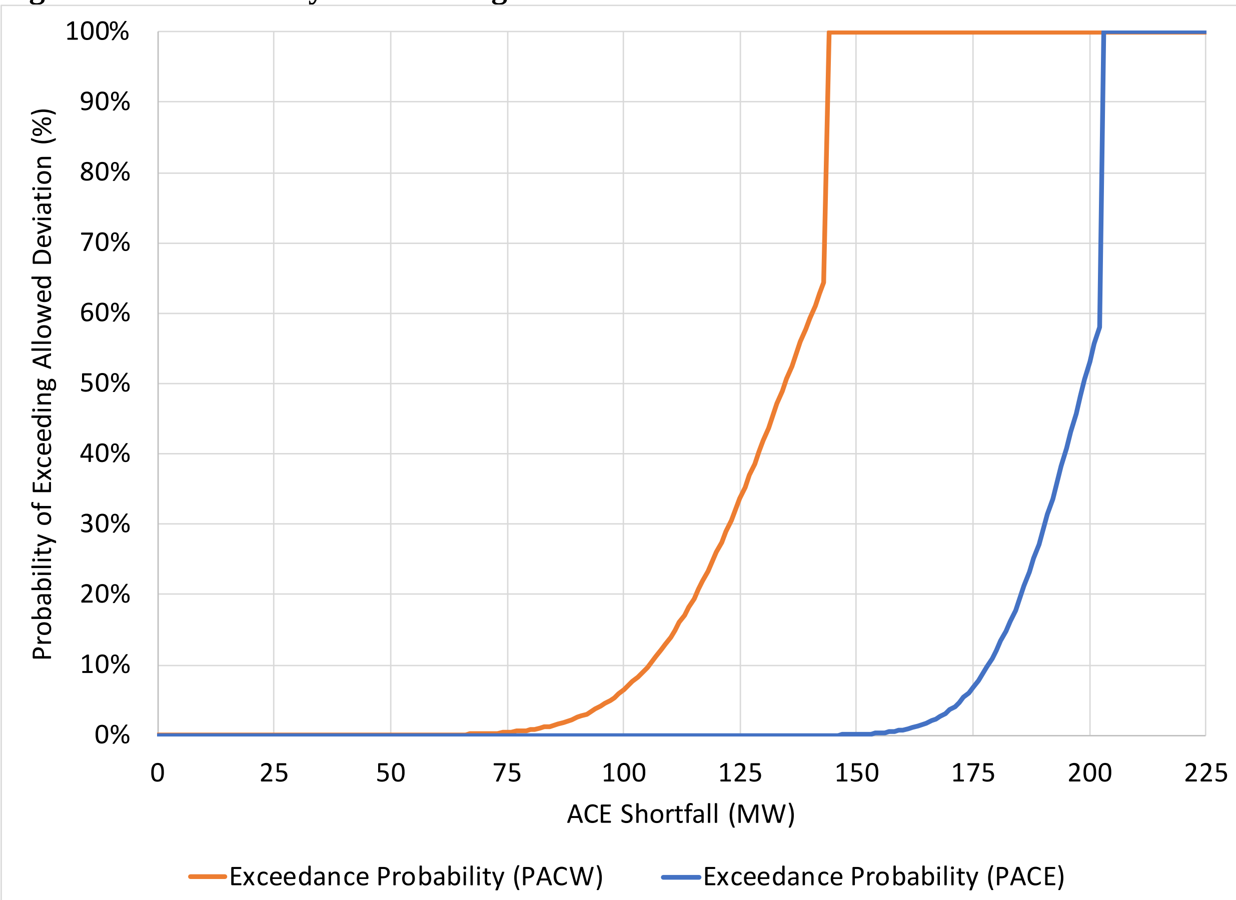
Even if insufficient regulation reserve capability is available to compensate for a thirty-minute sustained deviation, a violation of BAL-001-2 does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 Hz, ACE deviations are increasingly restricted for BAAs that are contributing to the shortfall, i.e. those BAAs with higher loads than resources. A BAA commits a BAL-001-2 reliability violation if in any thirty-minute interval it does not have at least one minute when its ACE is within its Balancing Authority ACE Limit.

While the specific Balancing Authority ACE Limit for a given interval cannot be known in advance, the historical probability distribution of Balancing Authority ACE Limit values is known. Figure F.2 below shows the probability of exceeding the allowed deviation during a five-minute interval for a given level of ACE shortfall. For instance, an 82 MW ACE shortfall in PACW has a one percent chance of exceeding the Balancing Authority ACE Limit. WECC-wide frequency can change rapidly and without notice, and this causes large changes in the Balancing Authority ACE Limit over short time frames. Maintaining ACE within the Balancing Authority ACE Limit under those circumstances can require rapid deployment of large amounts of operating reserve. To limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing

Authority ACE Limit or four times L_{10}. This also limits the occurrence of transmission flows that exceed path ratings as result of large variations in ACE.[19,20] This cap is reflected in Figure F.2.

Figure F.2 - Probability of Exceeding Allowed Deviation



In 2018-2019, PacifiCorp's deviations and Balancing Authority ACE Limits were uncorrelated, which indicates that PacifiCorp's contribution to WECC-wide frequency is small. PacifiCorp's deviations and Balancing Authority ACE Limits were also uncorrelated when periods with large deviations were examined in isolation. If PacifiCorp's large deviations made distinguishable contributions to the Balancing Authority ACE Limit, ACE shortfalls would be more likely to exceed the Balancing Authority ACE Limit during large deviations. Since this is not the case, the probability of exceeding the Balancing Authority ACE Limit is lower, and less regulation reserve is necessary to comply with the BAL-001-2 standard.

Regulation Reserve Forecast: Amount Held

To calculate the amount of regulation reserve required to be held while being compliant with BAL-001-2 – using a LOLP of 0.5 hours per year or less – a quantile regression methodology was used. Quantile regression is a type of regression analysis. Whereas the typical method of ordinary least

[19] "Regional Industry Initiatives Assessment." NWPP MC Phase 3 Operations Integration Work Group. Dec. 31, 2014. Pg. 14. Available at: www.nwpp.org/documents/MC-Public/NWPP-MC-Phase-3-Regional-Industry-Initiatives-Assessment12-31-2014.pdf

[20] "NERC Reliability-Based Control Field Trial Draft Report." Western Electricity Coordinating Council. Mar. 25, 2015. Available at: www.wecc.biz/Reliability/RBC%20Field%20Trial%20Report%20Approved%203-25-2015.pdf

squares results in estimates of the conditional mean (50th percentile) of the response variable given certain values of the predictor variables, quantile regression aims at estimating other specified percentiles of the response variable. Eight regressions were prepared, one for each class (load/wind/solar/non-VER) and area (PACE/PACW). Each regression uses the following variables:

- Response Variable: the error in each interval, in megawatts;
- Predictor Variable: the forecasted generation or load in each interval, expressed as a percentage of area capacity;

The forecasted generation or load in each interval used as the predictor variable contributes to the regression as a combination of linear, square, and higher order exponential effects. Specifically, the regression identifies coefficients that correspond to the following functions for each class:

Load Error: Load Forecast^1 + Constant
Wind Error: Wind Forecast^2 + Wind Forecast^1
Solar Error: Solar Forecast^4 + Solar Forecast^3 + Solar Forecast^2 + Solar Forecast^1
Non-VER Error: Non-VER Forecast^2 + Non-VER Forecast^1

The instances requiring the largest amounts of regulation reserve occur infrequently, and many hours have very low requirements. If periods when requirements are likely to be low can be distinguished from periods when requirements are likely to be high, less regulation reserve is necessary to achieve a given reliability target. The regulation reserve forecast is not intended to compensate for every potential deviation. Instead, when a shortfall occurs, the size of that shortfall determines the probability of exceeding the Balancing Authority ACE Limit and a reliability violation occurring. The forecast is adjusted to achieve a cumulative LOLP that corresponds to the annual reliability target.

Regulation Reserve Forecast

Overview

The following forecasts are polynomial functions that cover a targeted percentile of all historical deviations. These forecasts are stand-alone forecasts, based on the difference between hour-ahead base schedules and actual meter data, expressing the errors as a function of the level of forecast. The stand-alone reserve requirement shown achieves the annual reliability target of 0.5 hours per year, after accounting for the dynamic Balancing Authority ACE Limit. The combined diversity error system requirements are discussed later in the study. Figure F.3- Figure F.8 illustrate the relationship between the regulation reserve requirements during 2018-2019 and the forecasted level of output, for each resource class and control area. Both the regulation reserve requirements and the forecasted level of output are expressed as a percentage of resource nameplate (i.e., as a capacity factor). Figure F.9 and Figure F.10 illustrate the same relationship between the regulation reserve requirements during 2018-2019 and the forecasted load for each control area. Both the regulation reserve requirements and the forecasted load are expressed as a percentage of the annual peak load (i.e., as a load factor).

Figure F.3 - Wind Regulation Reserve Requirements by Forecast - PACE

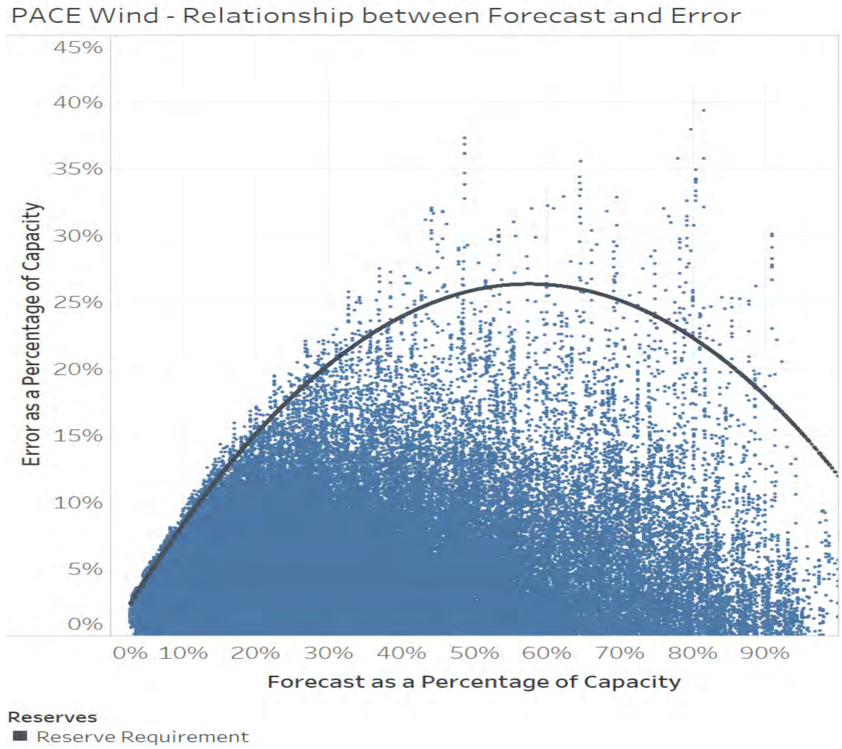


Figure F.4 - Wind Regulation Reserve Requirements by Forecast Capacity Factor - PACW

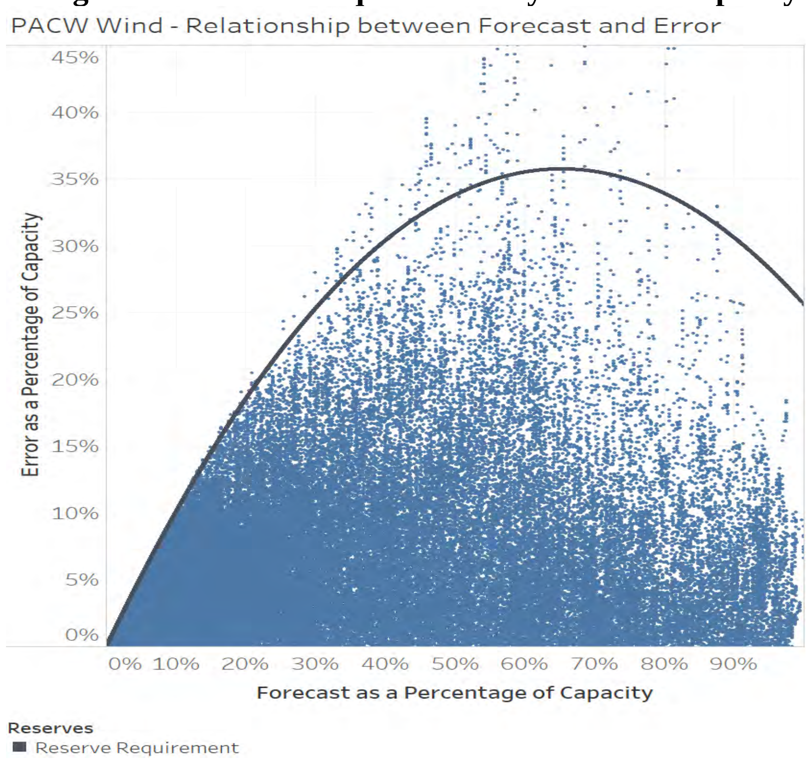


Figure F.5 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACE

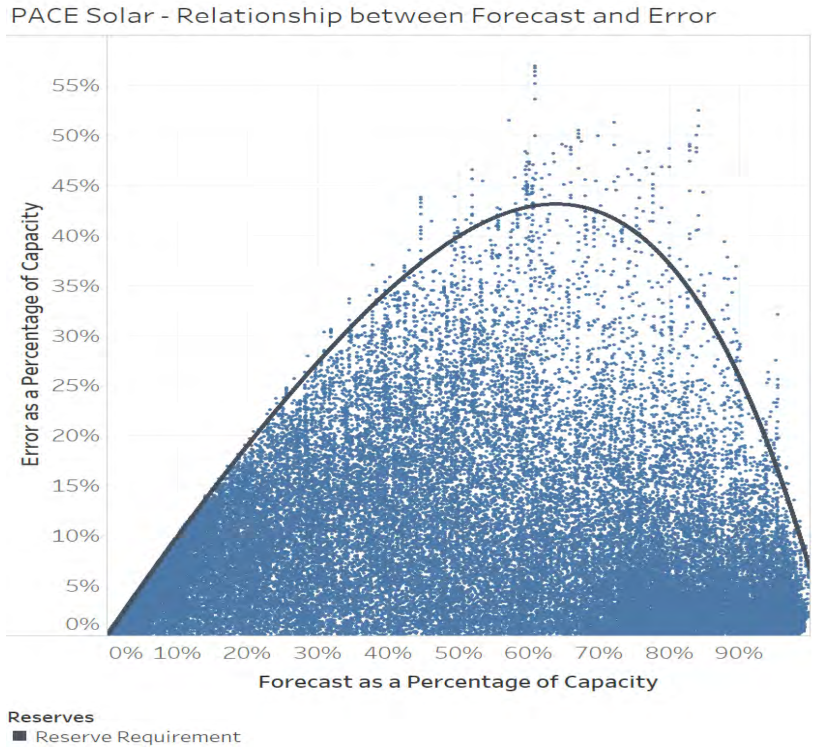


Figure F.6 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACW

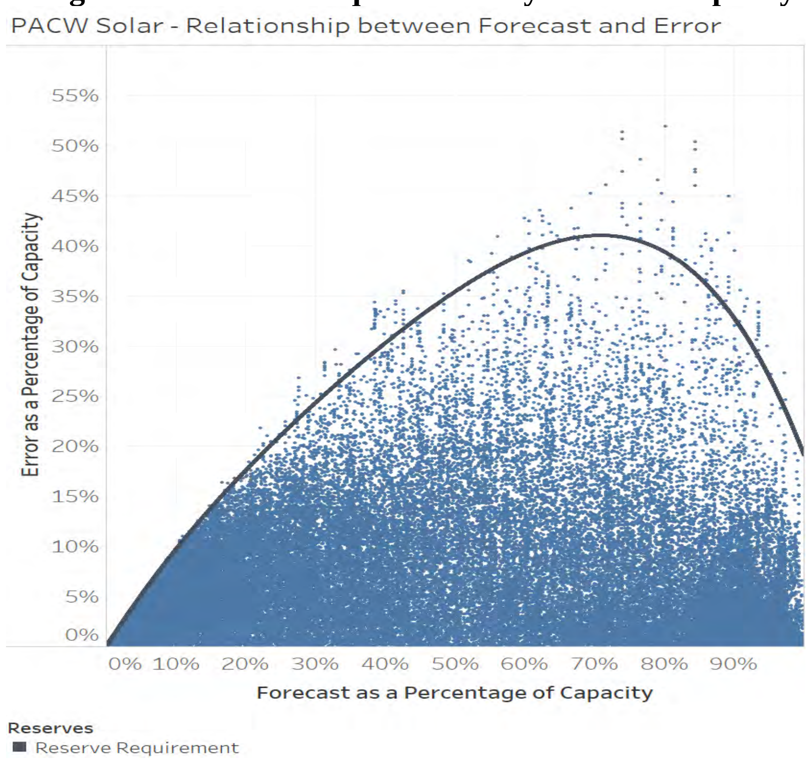


Figure F.7 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACE

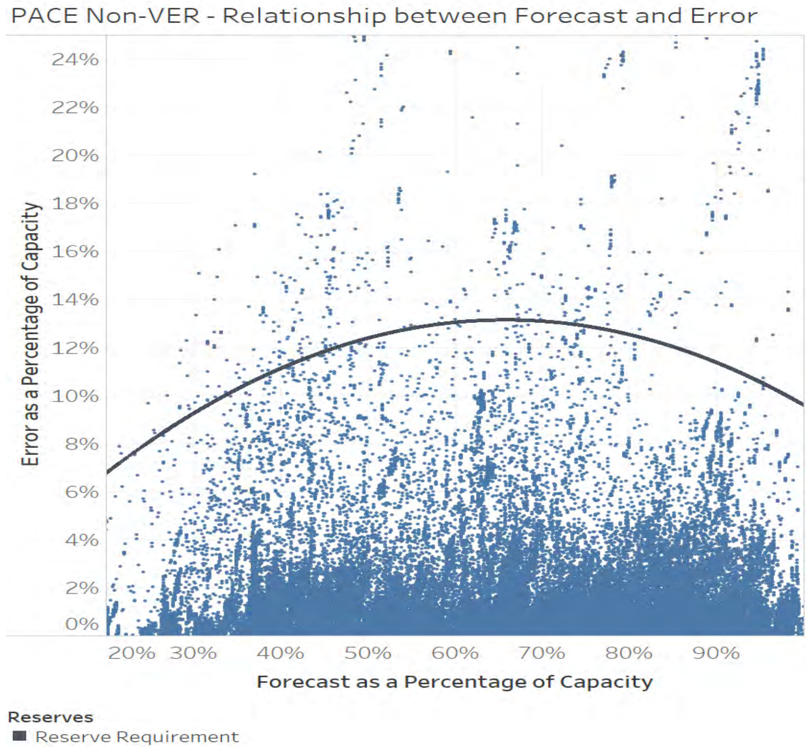


Figure F.8 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACW

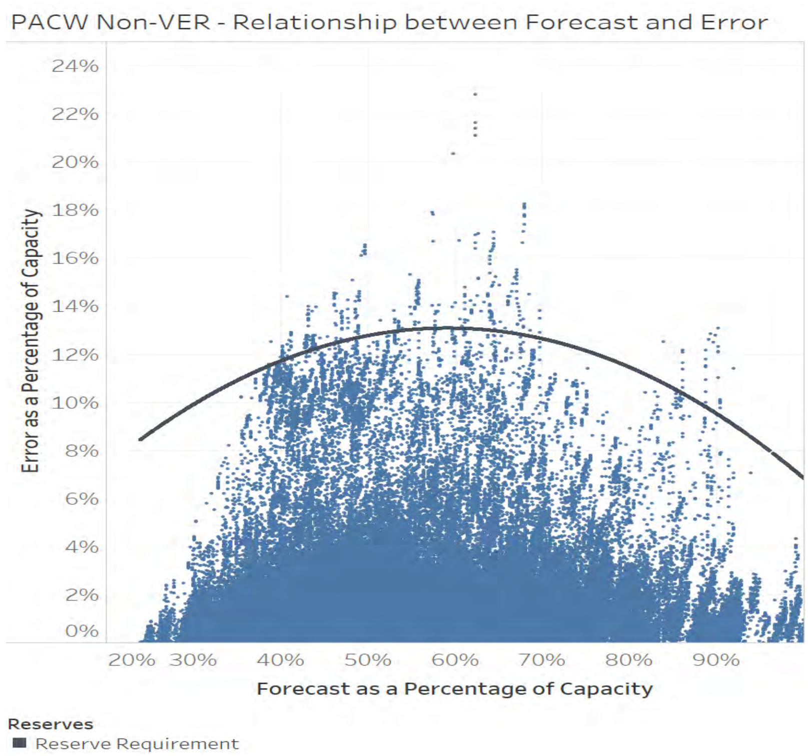


Figure F.9 – Stand-alone Load Regulation Reserve Requirements - PACE

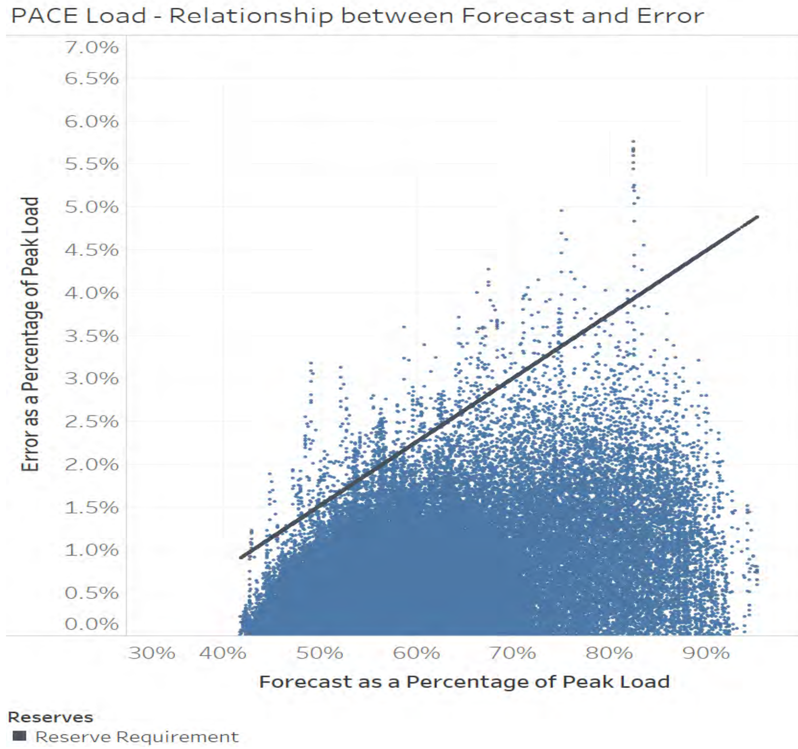
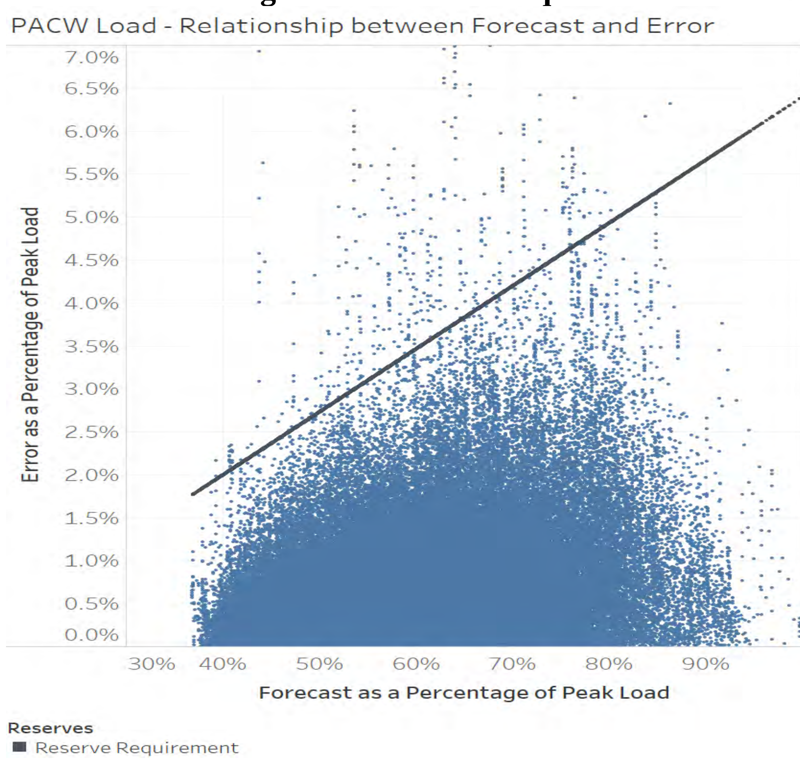


Figure F.10 – Stand-alone Load Regulation Reserve Requirements - PACW



The results of the analysis are shown in Table F.3 below.

Table F.3 – Summary of Stand-alone Regulation Reserve Requirements

Scenario	Stand-alone Regulation Forecast (aMW)	Capacity (MW)	Stand-alone Regulation Forecast (%)
Non-VER	106	1,304	8.2%
Load	334	10,094	3.3%
VER - Wind	457	2,745	16.7%
VER - Solar	159	1,080	14.8%
Total	**1,057**		

Portfolio Diversity and EIM Diversity Benefits

The EIM is a voluntary energy imbalance market service through the CAISO where market systems automatically balance supply and demand for electricity every fifteen and five minutes, dispatching least-cost resources every five minutes.

PacifiCorp and CAISO began full EIM operation on November 1, 2014. Several additional participants have since joined the EIM, and more participants are scheduled to join in the next several years. PacifiCorp's participation in the EIM results in improved power production forecasting and optimized intra-hour resource dispatch. This brings important benefits including reduced energy dispatch costs through automatic dispatch, enhanced reliability with improved situational awareness, better integration of renewable energy resources, and reduced curtailment of renewable energy resources.

The EIM also has direct effects related to regulation reserve requirements. First, because of EIM participation, PacifiCorp has improved data used in the analysis contained in this FRS. The data and control provided by the EIM allow PacifiCorp to achieve the portfolio diversity benefits described in the first part of this section. Second, the EIM's intra-hour capabilities across the broader EIM footprint provide the opportunity to reduce the amount of regulation reserve necessary for PacifiCorp to hold, as further explained in the second part of this section.

Portfolio Diversity Benefit

The regulation reserve forecasts described above independently ensure that the probability of a reliability violation for each class remains within the reliability target; however, the largest deviations in each class tend not to occur simultaneously, and in some cases, deviations will occur in offsetting directions. Because the deviations are not occurring at the same time, the regulation reserve held can cover the expected deviations for multiple classes at once and a reduced total quantity of reserve is sufficient to maintain the desired level of reliability. This reduction in the reserve requirement is the diversity benefit from holding a single pool of reserve to cover deviations in Solar, Wind, Non-VERs, and Load. As a result, the regulation reserve forecast for the portfolio can be reduced while still meeting the reliability target. In the historical period, portfolio diversity from the interactions between the various classes results in a regulation reserve requirement that is 36% lower than the sum of the stand-alone requirements, or approximately 679 MW.

EIM Diversity Benefit

In addition to the direct benefits from EIM's increased system visibility and improved intra-hour operational performance described above, the participation of other entities in the broader EIM footprint provides the opportunity to further reduce the amount of regulation reserve PacifiCorp must hold.

By pooling variability in load and resource output, EIM entities reduce the quantity of reserve required to meet flexibility needs. The EIM also facilitates procurement of flexible ramping capacity in the fifteen-minute market to address variability that may occur in the five-minute market. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA requirements. This difference is known as the "diversity benefit" in the EIM. This diversity benefit reflects offsetting variability and lower combined uncertainty. This flexibility reserve (uncertainty requirement) is in addition to the spinning and supplemental reserve carried against generation or transmission system contingencies under the NERC standards.

The CAISO calculates the EIM diversity benefit by first calculating an uncertainty requirement for each individual EIM BAA and then by comparing the sum of those requirements to the uncertainty requirement for the entire EIM area. The latter amount is expected to be less than the sum of the uncertainty requirements from the individual BAAs due to the portfolio diversification effect of forecasting a larger pool of load and resources using intra-hour scheduling and increased system visibility in the hypothetical, single-BAA EIM. Each EIM BAA is then credited with a share of the diversity benefit calculated by CAISO based on its share of the stand-alone requirement relative to the total stand-alone requirement.

The EIM does not relieve participants of their reliability responsibilities. EIM entities are required to have sufficient resources to serve their load on a standalone basis each hour before participating in the EIM. Thus, each EIM participant remains responsible for all reliability obligations. Despite these limitations, EIM imports from other participating BAAs can help balance PacifiCorp's loads and resources within an hour, reducing the size of reserve shortfalls and the likelihood of a Balancing Authority ACE Limit violation. While substantial EIM imports do occur in some hours, it is only appropriate to rely on PacifiCorp's diversity benefit associated with EIM participation, as these are derived from the structure of the EIM rather than resources contributed by other participants.

Table F.4 below provides a numeric example of uncertainty requirements and application of the calculated diversity benefit.

Table F.4 – EIM Diversity Benefit Application Example

	a	b	c	d	e =a+b+c+d	f	g = e-f	h = g / e	i = c * h	j = c - i
Hour	CAISO req't. before benefit (MW)	NEVP req't. before benefit (MW)	PACE req't. before benefit (MW)	PACW req't. before benefit (MW)	Total req't. before benefit (MW)	Total req't. after benefit (MW)	Total diversity benefit (MW)	Diversity benefit ratio (MW)	PACE benefit (MW)	PACE req't. after benefit (MW)
1	550	110	165	100	925	583	342	37.00%	61	104
2	600	110	165	100	975	636	339	34.80%	57	108
3	650	110	165	110	1,035	689	346	33.40%	55	110
4	667	120	180	113	1,080	742	338	31.30%	56	124

While the diversity benefit is uncertain, that uncertainty is not significantly different from the uncertainty in the Balancing Authority ACE Limit previously described. In the FRS, PacifiCorp has credited the regulation reserve forecast based on a historical distribution of calculated EIM diversity benefits. While this FRS considers regulation reserve requirements in 2018-2019, the CAISO identified an error in their calculation of uncertainty requirements in early 2018. CAISO's published uncertainty requirements and associated diversity benefits are now only valid for March 2018 forward. To capture these additional benefits for this analysis, PacifiCorp has applied the historical distribution of EIM diversity benefits from the 12 months beginning March 2018. In the historical study period, EIM diversity benefits used in the FRS would have reduced regulation reserve requirements by approximately 140 MW.

The inclusion of EIM diversity benefits in the FRS reduces the magnitude, and thus probability, of reserve shortfalls and, in doing so, reduces the overall regulation reserve requirement. This allows PacifiCorp's forecasted requirements to be reduced. As shown in Table F.5 below, the resulting regulation reserve requirement is 540 MW, which is a 49 percent reduction (including the portfolio diversity benefit) compared to the stand-alone requirement for each class. This portfolio regulation forecast is expected to achieve an LOLP of 0.5 hours per year.

Table F.5 – 2018-2019 Results with Portfolio Diversity and EIM Diversity Benefits

Scenario	Stand-alone Regulation Forecast (aMW)	Stand-alone Rate (%)	Portfolio Regulation Forecast w/EIM (aMW)	Portfolio Rate (%)	Capacity (MW)	Rate Determinant
Non-VER	106	8.2%	55	4.2%	1,304	Nameplate
Load	334	3.3%	172	1.7%	10,094	12 CP
VER - Wind	457	16.7%	237	8.6%	2,745	Nameplate
VER - Solar	159	14.8%	76	7.1%	1,080	Nameplate
Total	**1,057**		**540**			

Fast-Ramping Reserve Requirements

As previously discussed, Requirement 1 of BAL-001-2 specifies that PacifiCorp's CPS1 score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated on a monthly basis, it does not require a response to each and every ACE event, but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month.

The Regulation Reserve Forecast described above is evaluating requirements for extreme deviations that are at least 30 minutes in duration, for compliance with Requirement 2 of BAL-001-2. In contrast, compliance with CPS1 requires reserve capability to compensate for most conditions over a minute-to-minute basis. These fast-ramping resources would be deployed frequently and would also contribute to compliance with Requirement 2 of BAL-001-2, so they are a subset of the Regulation Reserve Forecast described above.

To evaluate CPS1 requirements, PacifiCorp compared the net load change for each five-minute interval in the study period to the corresponding value for Requirement 2 compliance in that hour from the Regulation Reserve Forecast, after accounting for diversity (resulting in a 540 MW average requirement). Resources may deploy for Requirement 2 compliance over up to 30 minutes, so the average requirement of 540 MW would require ramping capability of at least 18.0 MW per minute (540 MW / 30 minutes).

Because CPS1 is averaged and evaluated monthly, it does not require a response to each and every ACE event, but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month. Resources capable of ensuring compliance in 95 percent of intervals are expected to be sufficient to meet CPS1 and given that ACE may deviate in either a positive or negative direction, the 97.5th percentile of incremental requirements versus Requirement 2 in that interval was evaluated. At the 97.5th percentile, fast ramping requirements for PACE and PACW are 1.7 MW/minute and 0.8 MW/minute higher than the Requirement 2 ramp rate, respectively; however, if dynamic transfers between the BAAs are available, the 97.5th percentile for system is 0.6 MW / minute lower than the Requirement 2 value. When viewed on a system basis, this means that 30-minute ramping capability held for Requirement 2 would be sufficient to cover an adequate portion of the fast-ramping events to ensure CPS1 compliance.

Note that resources must respond immediately to ensure compliance with Requirement 1, as performance is measured on a minute-to-minute basis. As a result, resources that respond after a delay, such as quick-start gas plants or certain interruptible loads, would not be suitable for Requirement 1 compliance, so these resources cannot be allocated the entire regulation reserve requirement. However, because Requirement 1 compliance is a small portion of the total regulation reserve requirement, these restrictions on resource type are unlikely to be a meaningful constraint.

In addition, CPS1 compliance is weighted toward performance during conditions when interconnection frequency deviations are large. The largest frequency deviations would also result in deployment of frequency response reserves, which are somewhat larger in magnitude, though they have a less stringent performance metric under BAL-003-2, based on median response during the largest events.

In light of the overlaps with BAL-001-2 Requirement 2 and BAL-003-2 described above, CPS1 compliance is not expected to result in an additional requirement beyond what is necessary to comply with those standards.

Portfolio Regulation Reserve Requirements

The IRP portfolio optimization process contemplates the addition of new wind and solar capacity as part of its selection of future resources, as well as changes in peak load due to load growth and energy efficiency measure selection. These load and resource changes are expected to drive changes in PacifiCorp's regulation reserve requirements that will vary from portfolio to portfolio.

The locations that have been identified as likely sites for future wind and solar additions are in relatively close proximity to existing wind and solar resources, and PacifiCorp's portfolio of resources is already relatively diverse with significant wind in Wyoming, along the Columbia River gorge, and in eastern Idaho/western Wyoming and significant solar in southern Utah and southern Oregon. Because future resources are likely to be added in relatively close proximity to these existing resources, they are not likely to change the diversity for that class of resources as a whole. Given the sizeable sample of existing wind and solar resources in PACE and PACW, maintaining the existing level of diversity as a class of resources doubles or quadruples is a more likely outcome than the continuing improvements previously assumed in the 2019 FRS. With that in mind, the incremental regulation reserve analysis for the 2021 FRS methodology assumes that wind, solar, and load deviations scale linearly with capacity increases from the actual data in the 2018-2019 historical period.

While diversity within each class is not expected to change significantly, there is the opportunity for greater diversity among the wind, solar, and load requirements. These portfolio-related benefits are inherently tied to the portfolio, so it is appropriate that they vary with the portfolio. To that end, the 2021 FRS methodology calculates the portfolio diversity benefits specific to a wide variety of wind and solar capacity combinations, rather than relying upon the historical portfolio diversity value.

As part of the portfolio diversity calculation, the analysis assumes that minimum EIM flexible reserve requirements and EIM diversity benefits scale with changes in portfolio capacity. EIM minimum flexible reserve requirements are tied to the uncertainty in PacifiCorp's requirements, which grow with changes portfolio capacity, so it would be impacted directly. EIM diversity benefits reflect PacifiCorp's share of stand-alone requirements relative to those of the rest of the BAA's participating in EIM. All else being equal, increases in PacifiCorp's portfolio capacity would result in a greater proportion of the EIM diversity benefits being allocated to PacifiCorp.

Portfolio diversity is driven by interplay among the deviations by wind, solar, and load, so it is not a single number, but rather is dependent on the specific conditions. The 2021 FRS methodology incorporates two mechanisms to better account for these interactions. First, a portfolio diversity value is calculated specific to each hour of the day in each season. Second, rather than applying an equal percentage reduction to all hours, diversity benefits are assumed to be highest when stand-alone requirements are highest. For example, there is more opportunity for offsetting requirements when load, wind, and solar all have significant stand-alone requirements. With that in mind, diversity is applied as an exponent to the incremental requirement more than the EIM minimum requirement. The result of this calculation is a diversity benefit which is highest for large reserve requirements, and which approaches zero as the requirement approaches the EIM minimum, as illustrated in Table F.6.

Table F.6 – Portfolio Diversity Exponent Example

			Incremental Requirement w/ Diversity (MW) By Diversity Exponent			Portfolio Diversity (%) By Diversity Exponent		
Stand-alone Reserve Req. (MW)	**EIM Floor (MW)**	**Stand-alone Incremental Req. (MW)**	**d = c ^ 75%**	**e = c ^ 85%**	**f = c ^ 95%**	**g = 1 - (b + d)/a**	**h = 1 - (b + e)/a**	**i = 1 - (b + f)/a**
a	**b**	**c = a - b**	**75%**	**85%**	**95%**	**75%**	**85%**	**95%**
200	200	0	0	0	0	0%	0%	0%
250	200	50	19	28	41	12%	9%	4%
300	200	100	32	50	79	23%	17%	7%
350	200	150	43	71	117	31%	23%	9%
400	200	200	53	90	153	37%	27%	12%
450	200	250	63	109	190	42%	31%	13%
500	200	300	72	128	226	46%	34%	15%

For each combination of wind and solar capacity, the hourly portfolio diversity exponents for each season are increased in a stepwise fashion until the risk of regulation reserve shortfalls during an interval is sufficiently low and the overall risk of regulation reserve shortfalls achieves the target of 0.5 hours per year. The resulting portfolio diversity is maximized for a combination of wind and solar as summarized in Table F.7 and Table F.8 for PacifiCorp East and PacifiCorp West, respectively.

Table F.7 – PacifiCorp East Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

East Wind Capacity MW	%	428 MW (50%)	855 MW (100%)	1,462 MW (166%)	2,502 MW (329%)	3,542 MW (493%)	4,582 MW (656%)	5,622 MW (820%)	6,662 MW (983%)
8,224	**548%**	17.2%	18.8%	20.6%					
7,184	**472%**	19.2%	21.5%	23.0%	25.5%	26.5%			
6,144	**395%**	22.9%	24.1%	25.6%	27.9%	28.5%	29.0%		
5,104	**319%**	26.0%	27.3%	29.2%	30.7%	30.7%	30.5%	29.5%	
4,064	**242%**	30.4%	31.6%	32.9%	33.8%	32.7%	32.8%	32.8%	
3,024	**166%**	35.0%	36.2%	38.5%	37.1%	37.6%	36.2%	33.9%	31.9%
1,575	**100%**		$\boxed{48.0\%}$	45.8%	43.1%	39.5%	35.8%	32.2%	29.4%
788	**50%**			46.4%	40.3%	36.4%	33.0%	30.0%	27.3%

East Solar Capacity

☐ 2018-2019 Actual Wind and Solar Capacity

Table F.8 – PacifiCorp West Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

West Wind Capacity MW	%	50% / 111 MW	100% / 221 MW	166% / 321 MW	329% / 1,041 MW	493% / 1,761 MW	656% / 2,481 MW	820% / 3,201 MW	983% / 3,921 MW
4,389	548%	21.1%	22.4%	22.9%					
3,669	472%	23.4%	24.8%	25.4%	29.0%	33.0%			
2,949	395%	26.2%	26.7%	27.6%	32.1%	34.8%	38.1%		
2,229	319%	29.6%	30.6%	31.4%	36.2%	39.5%	42.7%	42.7%	
1,509	242%	33.8%	34.5%	36.3%	40.8%	45.2%	46.2%	43.9%	
789	166%	38.8%	41.6%	43.1%	47.6%	48.4%	47.7%	45.0%	44.3%
726	100%		$\boxed{42.4\%}$	42.9%	48.6%	49.3%	47.7%	46.2%	44.4%
363	50%			41.7%	47.1%	49.8%	47.4%	45.0%	43.2%

West Solar Capacity

☐ 2018-2019 Actual Wind and Solar Capacity

After portfolio selection is complete, regulation reserve requirements are calculated specific to a portfolio's load, wind, and solar resources in each year. The hourly regulation reserve requirement varies as a function of annual peak load net of energy efficiency selections as well as total wind and solar capacity. The regulation reserve requirement also varies based on the hourly load net of energy efficiency and hourly wind and solar generation values. Diversity exponents specific to the wind and solar capacity in each year are applied by hour and season, by interpolating among the scenarios illustrated in Tables F.7 and F.8. For example, the diversity exponent for hour five in the spring for a PACW study with 1,000 MW of wind and 1,000 MW of solar would reflect a weighting of diversity exponents in hour five in the spring from four scenarios. The highest weighting would apply to the 789 MW wind/1,041 MW solar scenario, and successively lower weightings would apply to 1,509 MW wind/1,041 MW solar, 789 MW wind/321 MW solar, and 1,509 MW wind/321 MW solar, with the total weighting for all four scenarios summing to 100%.

Finally, an adjustment is made to account for the ability of resources that are combined with storage to offset their own generation shortfalls beyond what is already captured by the model. For example, combined solar and storage resources can offset their own generation shortfalls, up to their interconnection limit. In actual operation, a reduction in solar generation would enable additional storage discharge. However, within the PLEXOS model, there are no intra-hour variations in load or renewable resource output and thus no potential increase in storage discharge. Note that combined storage can only be discharged when there is a generation shortfall at the adjacent resource, so it cannot cover all shortfalls across the system. For example, many solar resources do not have co-located storage, and their errors would continue to need to be met with incremental reserves. Nonetheless, combined solar and storage can cover a portion of their own shortfalls, and that portion increases as more combined storage resources are added to the system. This adjustment reduces the hourly regulation reserve requirement that is entered in the model.

Regulation Reserve Cost

The PLEXOS model reports marginal reserve prices on an hourly basis. So long as the change in reserve obligations or capability from what was input for a study is relatively small, this reserve price can provide a reasonable estimate of the impact of changes in reserves, without requiring additional model runs.

To estimate wind and solar integration costs for the 2023 IRP, PacifiCorp prepared a PLEXOS scenario that reflected the final regulation reserve requirements, consistent with the Company's existing wind and resources plus selections in the preferred portfolio. Hourly regulation reserve prices were reported from this study.

Wind Integration

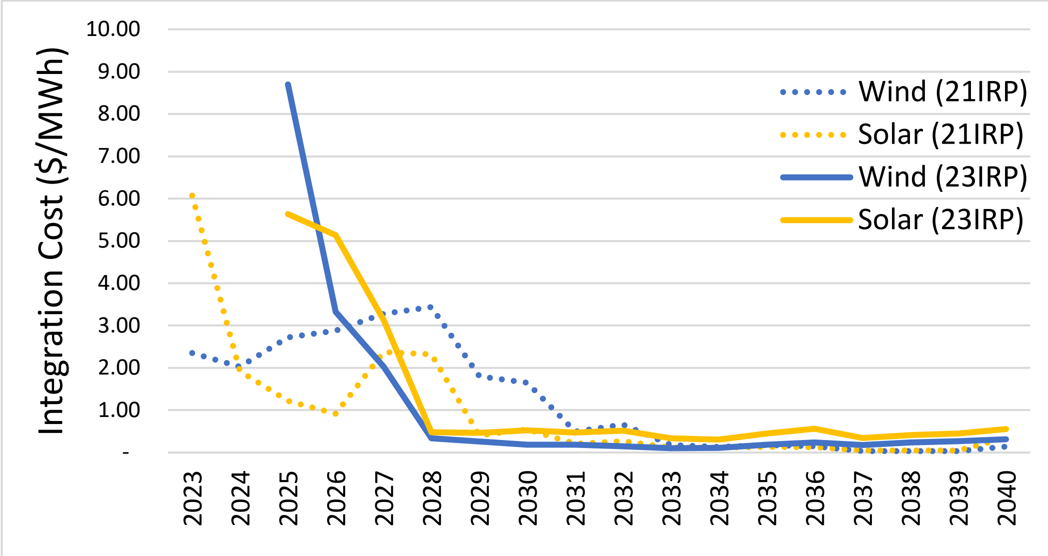
The wind reserve case uses the 2021 FRS methodology to recalculate the wind reserve requirement for a portfolio with 5 MW more wind resources starting in the first-year proxy resources are potentially available and extending to the end of the IRP study horizon (2025-2042). The change in resources is applied equally between PACE and PACW, and is allocated pro-rata among all wind resources in the area, such that the aggregate hourly capacity factor is not impacted by the change in capacity. The change in wind capacity results in incremental regulation reserve requirements that average approximately 16% of the nameplate capacity of the wind. Wind integration costs are calculated by multiplying the hourly change in reserve requirements (in MW) by the hourly regulation reserve price in each hour of the year, and then dividing that total by the incremental wind generation over the year.

Solar Integration

The solar reserve case uses the 2021 FRS methodology to recalculate the solar reserve requirement for a portfolio with 5 MW more solar resources starting in the first-year proxy resources are potentially available and extending to the end of the IRP study horizon (2025-2042). The reduction in resources is applied equally between PACE and PACW, and is allocated pro-rata among all solar resources in the area, such that the aggregate hourly capacity factor is not impacted by the change in capacity. The change in solar capacity results in incremental regulation reserve requirements that average approximately 10% of the nameplate capacity of the solar. Solar integration costs are calculated by multiplying the hourly change in reserve requirements (in MW) by the hourly regulation reserve price in each hour of the year, and then dividing that total by the incremental solar generation over the year.

The incremental regulation reserve cost results for wind and solar are shown in Figure F.11. The comparable regulation reserve costs from the 2021 FRS are also shown. Integration costs are high in the near term, as market prices are currently high and flexible capacity is somewhat limited. Integration costs fall as energy storage resources are added to the portfolio, as they can provide free operating reserves while charging and in any hour in which they are not discharging and not fully depleted, which for a four-hour energy storage resource is most of the day.

Figure F.11 – Incremental Wind and Solar Regulation Reserve Costs



Flexible Resource Needs Assessment

Overview

In its Order No. 12-013 issued on January 19, 2012, in Docket No. UM 1461 on "Investigation of matters related to Electric Vehicle Charging", the Oregon Public Utility Commission (OPUC) adopted the OPUC staff's proposed IRP guideline:

1. Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

2. Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and

3. Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options including the use of electric vehicles (EVs), on a consistent and comparable basis.

In this section, PacifiCorp first identifies its flexible resource needs for the IRP study period of 2023 through 2042, and the calculation method used to estimate those requirements. PacifiCorp then identifies its supply of flexible capacity from its generation resources, in accordance with the Western Electricity Coordinating Council (WECC) operating reserve guidelines, demonstrating that PacifiCorp has sufficient flexible resources to meet its requirements.

Forecasted Reserve Requirements

Since contingency reserve and regulation reserve are separate and distinct components, PacifiCorp estimates the forward requirements for each separately. The contingency reserve requirements are derived from the PLEXOS model. The regulating reserve requirements are part of the inputs to the PLEXOS model and are calculated by applying the methods developed in the Portfolio Regulation Reserve Requirements section. The contingency and regulation reserve requirements include three distinct components and are modeled separately in the 2023 IRP: 10-minute spinning reserve requirements, 10-minute non-spinning reserve requirements, and 30-minute regulation reserve requirements. The average reserve requirements for PacifiCorp's two balancing authority areas are shown in Table F.9 below.

Table F.9 - Reserve Requirements (Average MW)

Year	East Requirement			West Requirement		
	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)	Spin (10-minute)	Non-spin (10-minute)	Regulation (30-minute)
2023	342	342	850	272	272	261
2024	343	343	1,113	278	278	274
2025	347	347	1,268	283	283	291
2026	344	344	1,539	285	285	381
2027	347	347	1,534	289	289	422
2028	353	353	1,548	294	294	424
2029	355	355	1,640	296	296	425
2030	356	356	1,633	296	296	425
2031	358	358	1,602	298	298	424
2032	357	357	1,598	298	298	422
2033	359	359	1,597	299	299	424
2034	360	360	1,634	300	300	495
2035	361	361	1,837	301	301	606
2036	362	362	2,216	301	301	757
2037	365	365	1,801	303	303	910
2038	367	367	1,789	303	303	921
2039	368	368	1,963	305	305	947
2040	369	369	2,047	306	306	950
2041	382	382	2,048	310	310	954
2042	386	386	2,074	312	312	968

Flexible Resource Supply Forecast

Requirements by NERC and the WECC dictate the types of resources that can be used to serve the reserve requirements.

- **10-minute spinning reserve** can only be provided by resources currently online and synchronized to the transmission grid;

- **10-minute non-spinning reserve** may be served by fast-start resources that are capable of being online and synchronized to the transmission grid within ten minutes. Interruptible load can only provide non-spinning reserve. Non-spinning reserve may be provided by resources that are capable of providing spinning reserve.

- **30-minute regulation reserve** can be provided by unused spinning or non-spinning reserve. Incremental 30-minute ramping capability beyond the 10-minute capability captured in the categories above also counts toward this requirement.

The resources that PacifiCorp employs to serve its reserve requirements include owned hydro resources that have storage, owned thermal resources, and purchased power contracts that provide reserve capability.

Hydro resources are generally deployed first to meet the spinning reserve requirements because of their flexibility and their ability to respond quickly. The amount of reserve that these resources can provide depends upon the difference between their expected capacities and their generation level at the time. The hydro resources that PacifiCorp may use to cover reserve requirements in the PacifiCorp West balancing authority area include its facilities on the Lewis River and the Klamath River as well as its share of generation and capacity from the Mid-Columbia projects. In the PacifiCorp East balancing authority area, PacifiCorp may use facilities on the Bear River to provide spinning reserve.

Thermal resources are also used to meet the spinning reserve requirements when they are online. The amount of reserve provided by these resources is determined by their ability to ramp up within a 10-minute interval. For natural gas-fired combustion turbines, the amount of reserve can be close to the differences between their nameplate capacities and their minimum generation levels. In contrast, both coal and gas-converted steam turbines have slower ramp rates, and may ramp from minimum to maximum over an hour or more. In the current IRP, PacifiCorp's reserve needs are increasingly met by energy storage resources, including contracted resources and proxy resource selections in the preferred portfolio.

Table F.10 lists the annual reserve capability from resources in PacifiCorp's East and West balancing authority areas.[21] The changes in the flexible resource supply reflect retirement of existing resources, addition of new preferred portfolio resources, and variation in hydro capability due to forecasted streamflow conditions, and expiration of contracts from the Mid-Columbia projects that are reflected in the preferred portfolio.

[21] Frequency response capability is a subset of the 10-minute capability shown. Battery resources are capable of responding with their maximum output during a frequency event and can provide an even greater response if they were charging at the start of an event. PacifiCorp has sufficient frequency response capability at present and by 2025 the battery capacity currently contracted or added in the preferred portfolio will exceed PacifiCorp's current 266.4 MW frequency response obligation for a 0.3 Hz event. As a result, compliance with the frequency response obligation is not anticipated to require incremental supply.

Table F.10 - Flexible Resource Supply Forecast (Average MW)

Year	East Supply (10-Minute)	West Supply (10-Minute)	East Supply (30-Minute)	West Supply (30-Minute)
2023	1,301	922	1,823	895
2024	1,291	934	2,221	1,036
2025	1,247	949	2,606	992
2026	1,245	911	2,734	1,819
2027	1,231	1,104	2,714	1,970
2028	1,333	824	3,022	1,837
2029	1,274	858	3,233	1,925
2030	1,277	855	3,335	1,912
2031	1,282	858	3,304	1,887
2032	1,202	2,314	3,089	2,186
2033	1,237	2,295	3,202	2,206
2034	3,256	2,199	3,264	2,117
2035	3,357	2,138	3,529	2,273
2036	3,463	2,164	3,974	2,510
2037	3,544	2,171	3,748	2,495
2038	3,517	2,154	3,842	2,648
2039	3,672	2,190	3,965	2,695
2040	3,725	2,205	4,000	2,693
2041	3,742	2,157	4,078	2,697
2042	3,756	2,015	4,106	2,541

Figure F.12 and Figure F.13 graphically display the balances of reserve requirements and capability of spinning reserve resources in PacifiCorp's East and West balancing authority areas respectively. The graphs demonstrate that PacifiCorp's system has sufficient resources to serve its reserve requirements throughout the IRP planning period. Note that keeping minimum amounts in energy storage or bringing thermal plants online and/or reducing their generation while online could increase the available response beyond that shown in the figures, and accounts for some of the increase in supply after 2030. In addition, PacifiCorp currently can transfer a portion of the operating reserves held in either of its balancing authority areas to help meet the requirements of its other balancing authority area, based on the reserve need and relative economics of the available supply.

Figure F.12 - Comparison of Reserve Requirements and Resources, East Balancing Authority Area (MW)

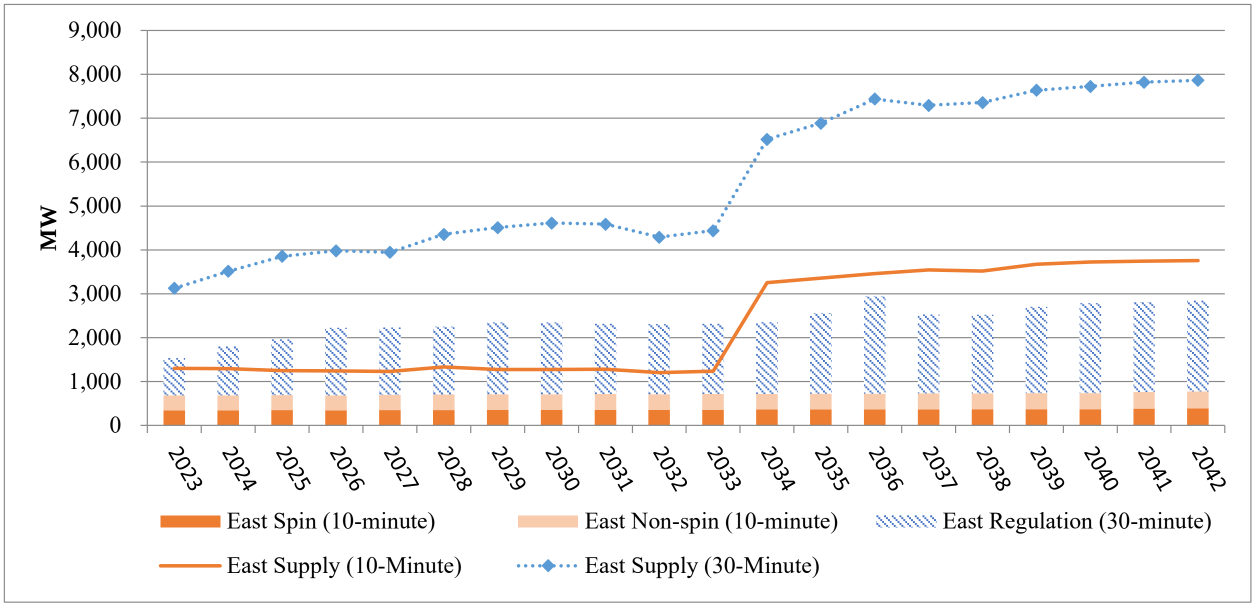
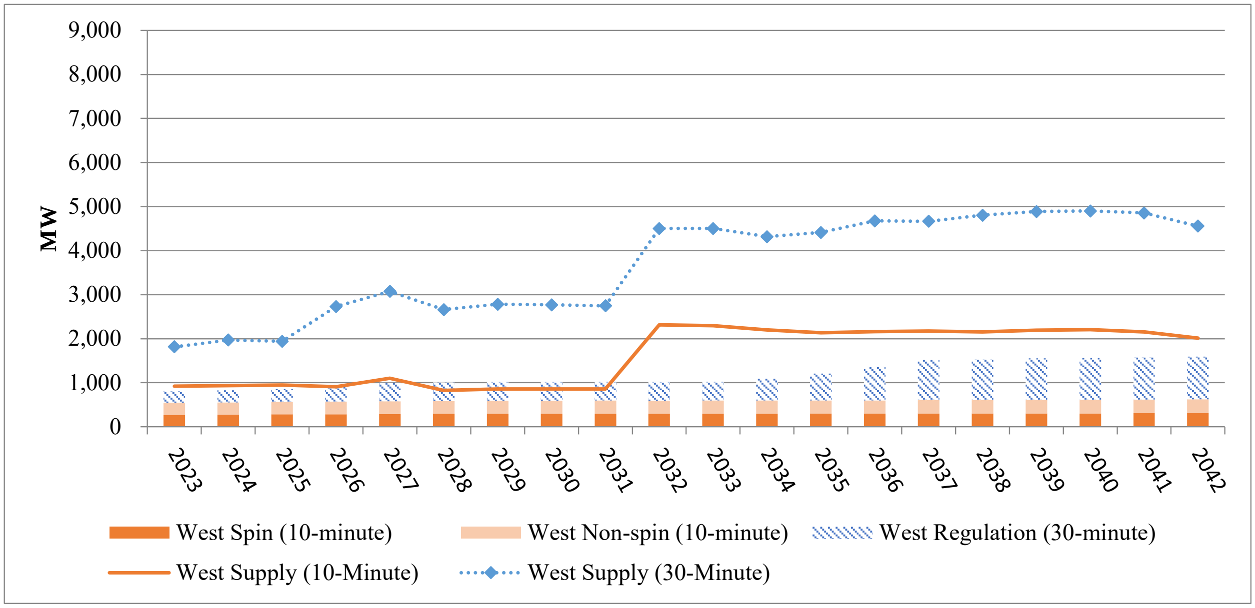


Figure F.13 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



Flexible Resource Supply Planning

In actual operations, PacifiCorp has been able to serve its reserve requirements and has not experienced any incidents where it was short of reserve. PacifiCorp manages its resources to meet its reserve obligation in the same manner as meeting its load obligation – through long term planning, market transactions, utilization of the transmission capability between the two balancing authority areas, and operational activities that are performed on an economic basis.

PacifiCorp and the California Independent System Operator Corporation implemented the energy imbalance market (EIM) on November 1, 2014, and participation by other utilities has expanded significantly with more participants scheduled for entry through 2023. By pooling variability in load and resource output, EIM entities reduce the quantity of reserve required to meet flexibility needs. Because variability across different BAAs may happen in opposite directions, the uncertainty requirement for the entire EIM footprint can be less than the sum of individual BAAs' requirements. This difference is known as the "diversity benefit" in the EIM. This diversity benefit reflects offsetting variability and lower combined uncertainty. PacifiCorp's regulation reserve forecast includes a credit to account for the diversity benefits associated with its participation in EIM.

As indicated in OPUC order 12-013, electric vehicle technologies may be able to meet flexible resource needs. For the first time in the 2023 IRP, electric vehicle load control is one of the demand response options available for selection. While electric vehicle load control was not one of the programs selected to the preferred portfolio, new demand response programs included in the preferred portfolio provide 275 average megawatts of operating reserves by 2030, and 860 average megawatts of operating reserves by 2042. While operating reserves supply is projected to be well in excess of operating reserve requirements, the rising supply of zero-cost renewable resources increases the value associated with shifting load within the day and seasonally, rather than just within the hour as contemplated in this appendix.

APPENDIX G – PLANT WATER CONSUMPTION STUDY

The information provided in this appendix is for PacifiCorp owned plants. Total water consumption and generation includes all owners for jointly-owned facilities.

Table G.1 – Plant Water Consumption with Acre-Feet per Year

			Acre-Feet Per Year					Net MWhs Per Year				4-year Average	
Plant Name	**Zero Discharge**	**Cooling Media**	**2019**	**2020**	**2021**	**2022**	**4-year Average**	**2019**	**2020**	**2021**	**2022**	**Gals/ MWH**	**GPM/ MW**
Chehalis		Air	63	66	71	47	62	2,431,536	2,407,519	2,248,237	2,172,465	9	0.1
Currant Creek	Yes	Air	101	95	113	85	98	2,917,279	2,335,426	2,746,290	2,805,979	12	0.2
Dave Johnston		Water	8,485	7,856	6,571	5,901	7,203	4,686,381	4,325,604	3,601,242	3,581,919	580	9.7
Gadsby		Water	281	409	339	454	371	134,182	133,410	83,008	118,821	1,029	17.2
Hunter	Yes	Water	15,808	15,103	16,326	13,426	15,166	8,681,784	7,988,203	9,248,963	7,381,184	594	9.9
Huntington	Yes	Water	9,028	7,929	12,019	11,717	10,173	4,897,541	4,515,305	6,263,658	5,673,115	621	10.4
Jim Bridger	Yes	Water	19,893	18,184	19,103	19,076	19,064	11,254,989	10,458,575	10,342,840	10,662,019	582	9.7
Lake Side		Water	3,894	4,075	4,421	4,591	4,245	5,063,816	5,560,112	6,389,355	6,578,673	235	3.9
Naughton	Yes	Water	10,195	7,622	7,236	6,929	7,996	2,840,374	2,659,033	2,596,446	2,456,201	988	16.5
Wyodak	Yes	Air	292	336	333	324	321	1,852,094	1,732,784	1,717,528	1,779,843	59	1.0
TOTAL			**68,040**	**61,675**	**66,531**	**62,551**	**64,699**	**44,759,976**	**42,115,971**	**45,237,567**	**43,210,219**	**481**	**8.0**

Gadsby includes a mix of both Rankine steam units and Brayton peaking gas turbines.

1 acre-foot of water is equivalent to 325,851 Gallons or 43,560 Cubic Feet.

Table G.2 – Plant Water Consumption by State (acre-feet)

UTAH PLANTS							
Plant Name	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Currant Creek	124	116	110	101	95	113	85
Gadsby	262	100	205	281	409	339	454
Hunter	14,225	15,383	14,751	15,808	15,103	16,326	13,426
Huntington	9,189	9,653	9,804	9,028	7,929	12,019	11,717
Lake Side	3,619	2,698	3,648	3,894	4,075	4,421	4,591
TOTAL	**27,419**	**27,950**	**28,518**	**29,112**	**27,611**	**33,217**	**30,274**

Percent of total water consumption = 45.4%

WYOMING PLANTS							
Plant Name	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Dave Johnston	8,864	8,231	8,325	8,485	7,856	6,571	5,901
Jim Bridger	18,000	19,047	20,067	19,893	18,184	19,103	19,076
Naughton	6,896	6,927	9,916	10,195	7,622	7,236	6,929
Wyodak	329	332	319	292	336	333	324
TOTAL	**34,090**	**34,537**	**38,627**	**38,865**	**33,998**	**33,243**	**32,230**

Percent of total water consumption = 54.6%

Table G.3 – Plant Water Consumption by Fuel Type (acre-feet)

COAL FIRED PLANTS							
Plant Name	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Dave Johnston	8,864	8,231	8,325	8,485	7,856	6,571	5,901
Hunter	14,225	15,383	14,751	15,808	15,103	16,326	13,426
Huntington	9,189	9,653	9,804	9,028	10,423	10,643	10,240
Jim Bridger	18,000	19,047	20,067	19,893	18,184	19,103	19,076
Naughton	6,896	6,927	9,916	10,195	7,622	7,236	6,929
Wyodak	329	332	319	292	336	333	324
TOTAL	**57,504**	**59,573**	**63,182**	**63,701**	**59,524**	**60,212**	**55,896**

Percent of total water consumption = 93.3%

NATURAL GAS FIRED PLANTS							
Plant Name	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Currant Creek	124	116	110	101	95	113	85
Chehalis	48	54	33	63	66	71	47
Gadsby	262	100	205	281	409	339	454
Lake Side	3,619	2,698	3,648	3,894	4,075	4,421	4,591
TOTAL	**4,053**	**2,968**	**3,996**	**4,339**	**4,644**	**4,943**	**5,178**

Percent of total water consumption = 6.7%

Table G.4 – Plant Water Consumption for Plants Located in the Upper Colorado River Basin (acre-feet)

Plant Name	2016	2017	2018	2019	2020	2021	2022
Hunter	14,225	15,383	14,751	15,808	15,103	16,326	13,426
Huntington	9,189	9,653	9,804	9,028	7,929	12,019	11,717
Naughton	6,896	6,927	9,916	10,195	7,622	7,236	6,929
Jim Bridger	18,000	19,047	20,067	19,893	18,184	19,103	19,076
TOTAL	**48,311**	**51,010**	**54,537**	**54,924**	**48,839**	**54,684**	**51,148**

Percent of total water consumption = 80.8%

APPENDIX H – STOCHASTIC PARAMETERS

Introduction

For the 2023 IRP, PacifiCorp updated and re-estimated the stochastic parameters provided in the 2021 IRP for use in the development of the 2023 IRP preferred portfolio.

Plexos, as used by PacifiCorp, develops portfolio cost scenarios via computational finance in concert with production simulation. The model stochastically shocks the case-specific underlying electricity price forecast as well as the corresponding case-specific key drivers (e.g., natural gas, loads, and hydro) and dispatches accordingly. Using exogenously calculated parameters (i.e., volatilities, mean reversions, and correlations), Plexos develops scenarios that bracket the uncertainty surrounding a driver; statistical sampling techniques are then employed to limit the number of representative scenarios to 50. The stochastic model used in Plexos is a two-factor (short- and long-run) mean reverting model.

PacifiCorp used short-run stochastic parameters for this Integrated Resource Plan (IRP); long-run parameters were set to zero since Plexos cannot re-optimize its capacity expansion plan. This inability to re-optimize or add capacity can create a problem when dispatching to meet extreme load and/or fuel price excursions, as often seen in long-term stochastic modeling. Such extreme out-year price and load excursions can influence portfolio costs disproportionately while not reflecting plausible outcome. Thus, since long-term volatility is the year-on-year growth rate, only the expected yearly price and/or load growth is simulated over the forecast horizon[1].

Key drivers that significantly affect the determination of prices tend to fall into two categories: loads and fuels. Targeting only key variables from each category simplifies the analysis while effectively capturing sensitivities on a larger number of individual variables. For instance, load uncertainty can encompass the sensitivities of weather, transmission availability, unit outages, and evolving end-uses. Depending on the region, fuel price uncertainty (especially natural gas) can encompass the sensitivities of weather, load growth, emissions, and hydro availability. The following sections summarize the development of stochastic process parameters and describe how these uncertain variables evolve over time.

Overview

Long-term planning demands specification of how important variables behave over time. For the case of PacifiCorp's long-term planning, important variables include natural gas and electricity prices, regional loads, and regional hydro generation. Modeling these variables involves not only a description of their expected value over time as with a traditional forecast, but also a description of the spread of possible future values. The following sections summarize the development of stochastic process parameters to describe how these uncertain variables evolve over time[2].

[1] Mean reversion is assumed to be zero in the long run.

[2] A stochastic or random process is the counterpart to a deterministic process. Instead of dealing with only one possible reality of how the variables might evolve over time, there is some indeterminacy in the future evolution described by probability distributions.

Volatility

The standard deviation[3](σ) is a measure of how widely values are dispersed from the average value:

$$\sigma = \sqrt{\frac{\sum_{i=1}^{n}(x_i - \mu)^2}{(n-1)}}$$

where μ is the average value of the observations {x1, x2,…,xn}, and n is the number of observations.

Volatility (σ_T) incorporates a time component so a variable with constant volatility has a larger spread of possible outcomes two years in the future than one year in the future:

$$\sigma_T = \sigma\sqrt{T}$$

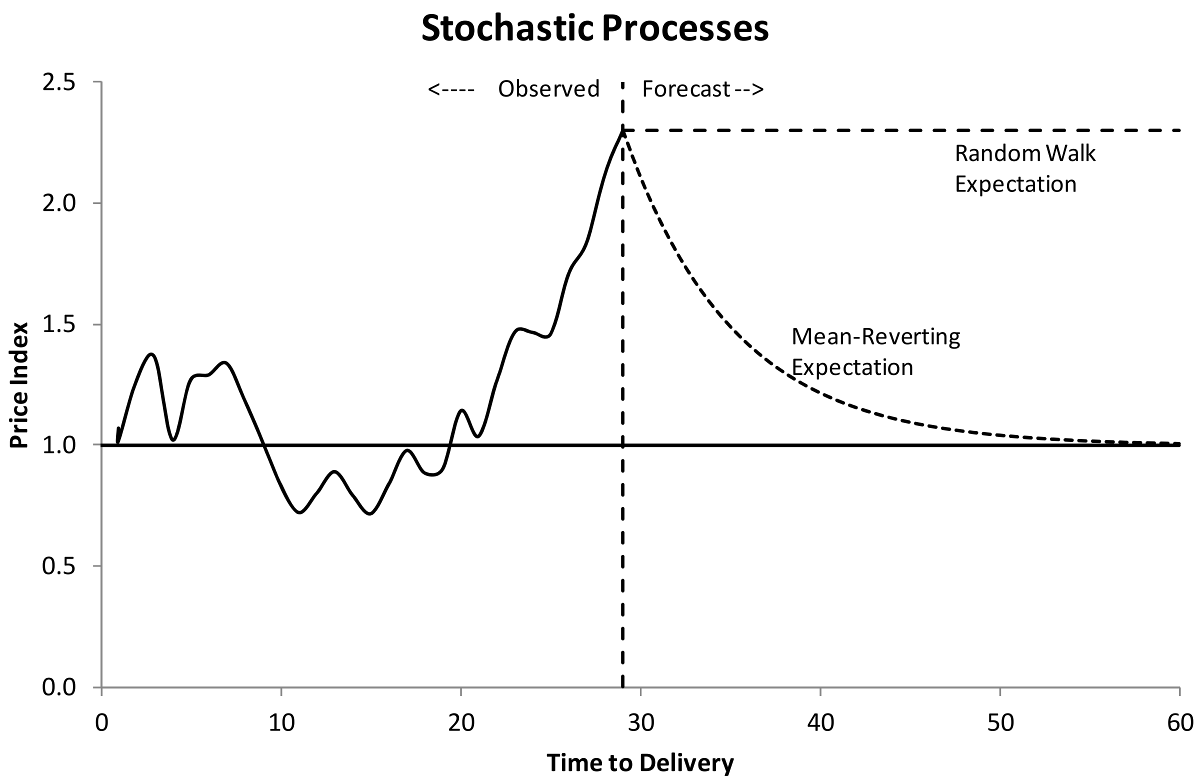
Volatilities are typically quoted on an annual basis but can be specified for any desired time (T). Suppose the annual volatility of load is two percent. This implies that the standard deviation of the range of possible loads a year from now is two percent, while the standard deviation four years from now is four percent.

Mean Reversion

If volatility was constant over the forecast period, then the standard deviation would increase linearly with the square root of time. This is described as a "Random Walk" process and often provides a reasonable assumption for long-term uncertainty. However, for energy commodities as well as many other variables in the short-term, this is not typically the case. Excepting seasonal effects, the standard deviation increases less quickly with longer forecast time. This is called a mean reverting process - variable outcomes tend to revert back towards a long-term mean after experiencing a shock.

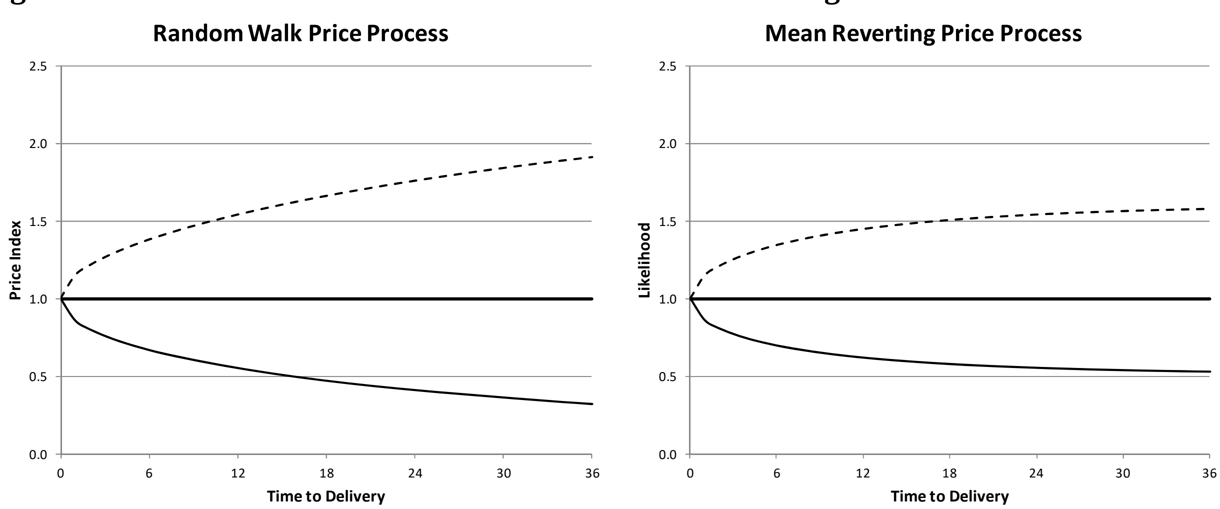
[3] "Standard Deviation" and "Variance" are standard statistical terms describing the spread of possible outcomes. The Variance equals the Standard Deviation squared.

Figure H.1 – Stochastic Processes



For a random walk process, the distribution of possible future outcomes continues to increase indefinitely, while for a mean reverting process, the distribution of possible outcomes reaches a steady-state. Actual observed outcomes will continue to vary within the distribution, but the distribution across all possible outcomes does not increase:

Figure H.2 – Random Walk Price Process and Mean Reverting Process



The volatility and mean reversion rate parameters combine to provide a compact description of the distribution of possible variable outcomes over time. The volatility describes the size of a typical shock or deviation for a particular variable and the mean reversion rate describes how quickly the variable moves back toward the long-run mean after experiencing a shock.

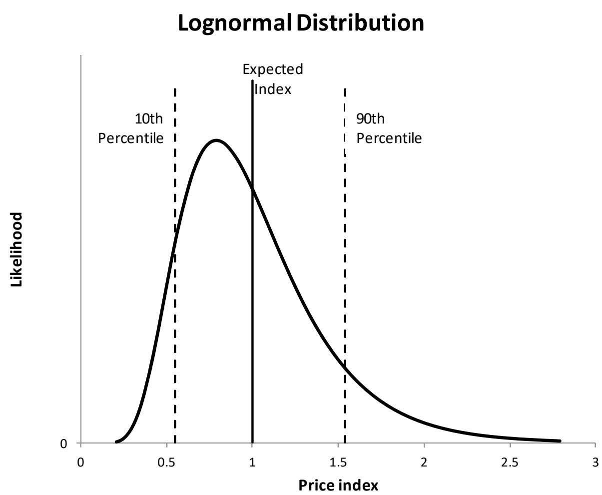
Estimating Short-term Process Parameters

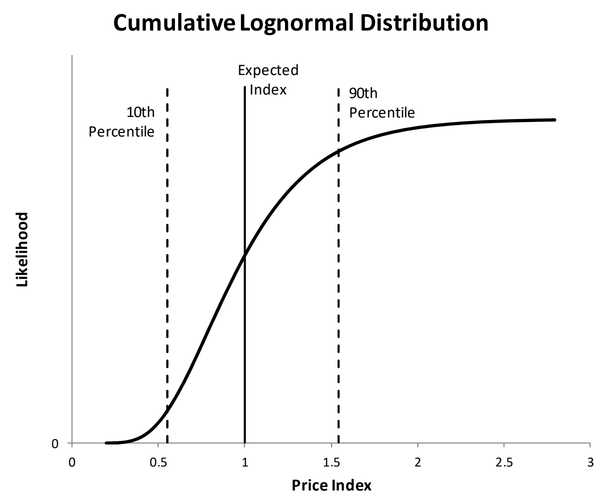
Short-term uncertainty can best be described as a mean reverting process. The factors that drive uncertainty in the short-term are generally short-lived, decaying back to long-run average levels. Short-term uncertainty is mainly driven by weather (temperature, windiness, rainfall) but can also be driven by short-term economic factors, congestion, outages, etc. The process for estimating short-term uncertainty parameters is similar for most variables of interest. However, each of PacifiCorp's variables have characteristics that make their processes slightly different. The process for estimating short-term uncertainty parameters is described in detail below for the most straightforward variable – natural gas prices. Each of the other variables is then discussed in terms of how they differ from the standard natural gas price parameter estimation process.

Stochastic Process Description

The first step in developing process parameter estimates for any uncertain variable is to determine the form of the distribution and time step for uncertainty. In the case of natural gas, and for prices in general, the lognormal distribution is a good representation of possible future outcomes. A lognormal distribution is a continuous probability distribution of a random variable whose logarithm is normally distributed[4]. The lognormal distribution is often used to describe prices because it is bounded on the bottom by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average:

Figure H.3 – Lognormal Distribution and Cumulative Lognormal Distribution





The time step for calculating uncertainty parameters depends on how quickly a variable can experience a significant change. Natural gas prices can change substantially from day-to-day and are reported on a daily basis, so the time step for analysis will be one day.

[4] A normal distribution is the most common continuous distribution represented by a bell-shaped curve that is symmetrical about the mean, or average, value.

All short-term parameters were calculated on a seasonal basis to reflect the different dynamics present during different seasons of the year. For instance, the volatility of gas prices is higher in the winter and lower in the spring and summer. Seasons were defined as follows:

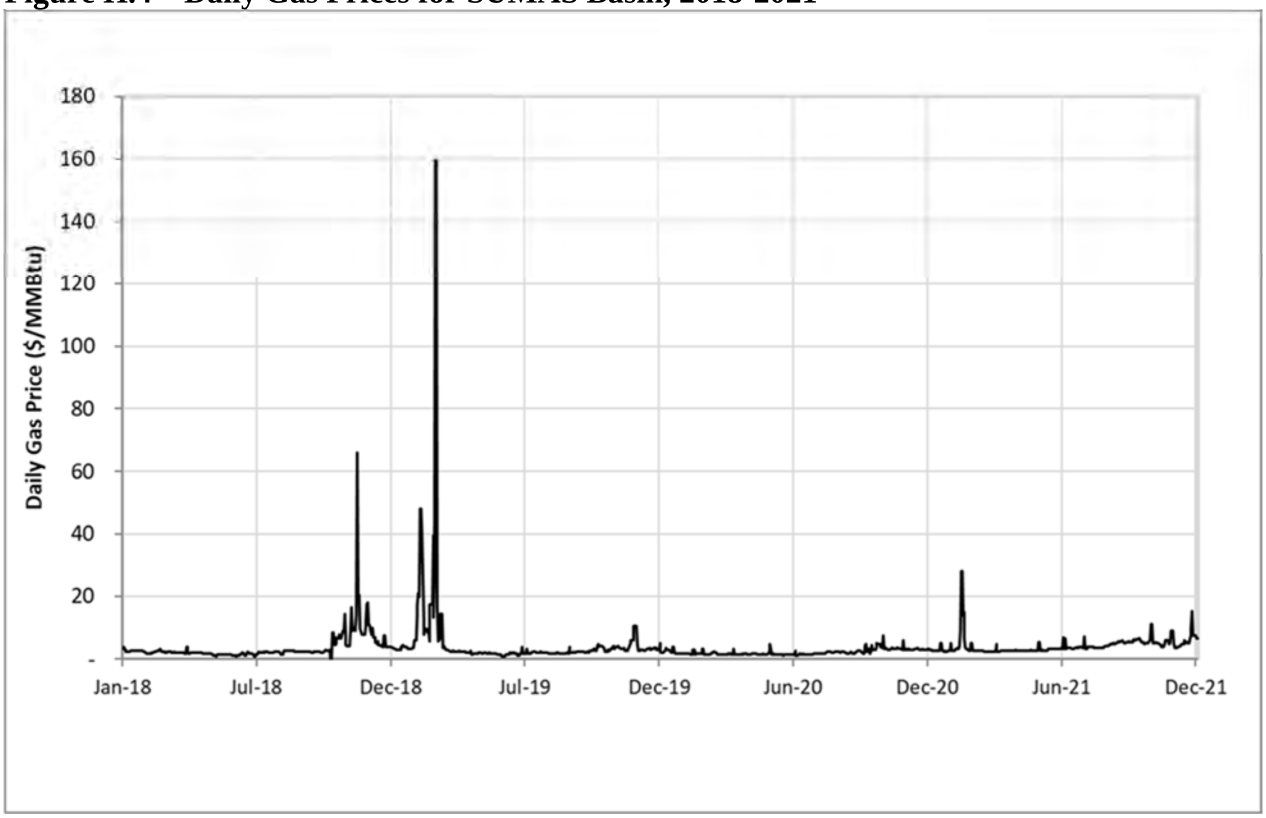
Table H.1 - Seasonal Definitions

Winter	December, January, and February
Spring	March, April, and May
Summer	June, July, and August
Fall	September, October, and November

Data Development

Basic Data Set:
The natural gas price data was organized into a consistent dataset with one natural gas price for each gas delivery point reported for each delivery day. The data was checked to make sure that there were no missing or duplicate dates. If no price is reported for a particular date, the date is included but left blank to maintain a consistent 24-hour time step between all observed prices. Four years of daily data from 2018 to 2021 was used for this short-term parameter analysis. The following chart shows the resulting data set for the Sumas gas basin:

Figure H.4 – Daily Gas Prices for SUMAS Basin, 2018-2021



Development of Price Index:
Uncertainty parameters are estimated by looking at the movement, or deviation, in prices from one day to the next. However, some of this movement is due to expected factors, not uncertainty. For

instance, gas prices are expected to be higher during winter or as we move toward winter. This expectation is already included in the gas price forecast and should not be considered a shock, or random event. To capture only the random or uncertain portion of price movements, a price index is developed that takes into account the expected portion of price movements. Three categories of price expectations are calculated:

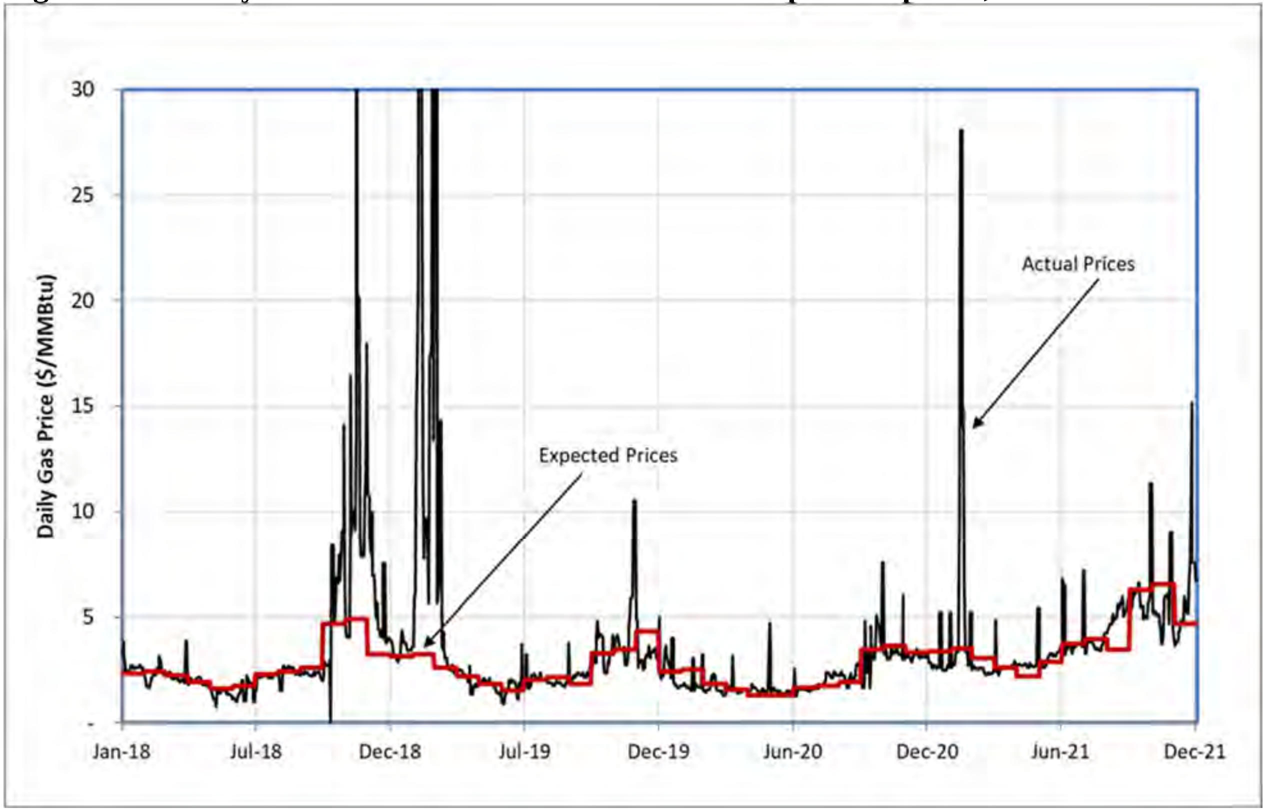
> Seasonal Median: The level of gas prices may be different from one year to the next. While this can be attributed to random movements or shocks in the gas markets, it is not a short-term event and should not be included in the short-term uncertainty process. To account for this possible difference in the level of gas prices, the median gas price for each season and year is calculated. For example, Sumas prices in the winter of 2018 average $2.68/MMBtu.
>
> Monthly Median: Within a season, there are different expected prices by month. For instance, within the fall season, November gas prices are expected to be much higher than September and October prices as winter is just around the corner. A monthly factor representing the ratio of monthly prices to the seasonal median price is calculated. For example, February prices in Sumas are 91 percent of the winter median price.
>
> Weekly Shape: Many variables exhibit a distinct shape across the week. For instance, loads and electricity prices are higher during the middle of the week and lower on the weekends. The expected shape of gas prices across the week was calculated and found to be insignificant (expected variation by weekday did not exceed three percent of the weekly average).

These three components – seasonal median, monthly shape, and weekly shape – combine to form an expected price for each day. For example, the expected price of gas in Sumas on February 1, 2018 was $2.21/MMBtu, the product of the seasonal median and the monthly shape factor

$$Expected\ Gas\ Price\ = Seasonal\ Median. Price * Monthly\ Shape\ within\ the\ Season$$

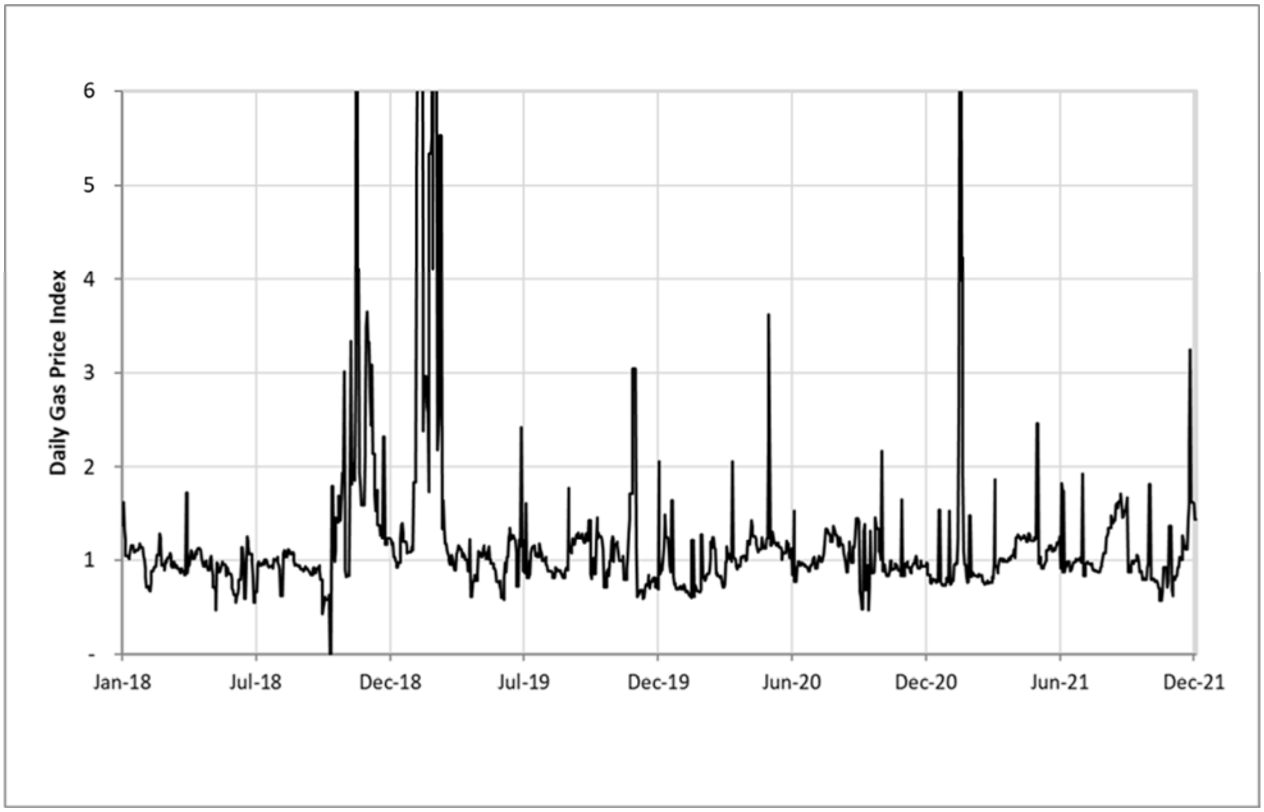
The following chart shows the comparison of the actual Sumas prices with the "expected" prices:

Figure H.5 – Daily Gas Prices for SUMAS Basin with "expected" prices, 2018-2021



Dividing the actual gas prices by the expected prices forms a price index with a median of one. This index, illustrated by the chart below, captures only the random component of price movements—the portion not explained by expected seasonal, monthly, and weekly shape.

Figure H.6 – Gas Price Index for SUMAS Basin, 2018-2021



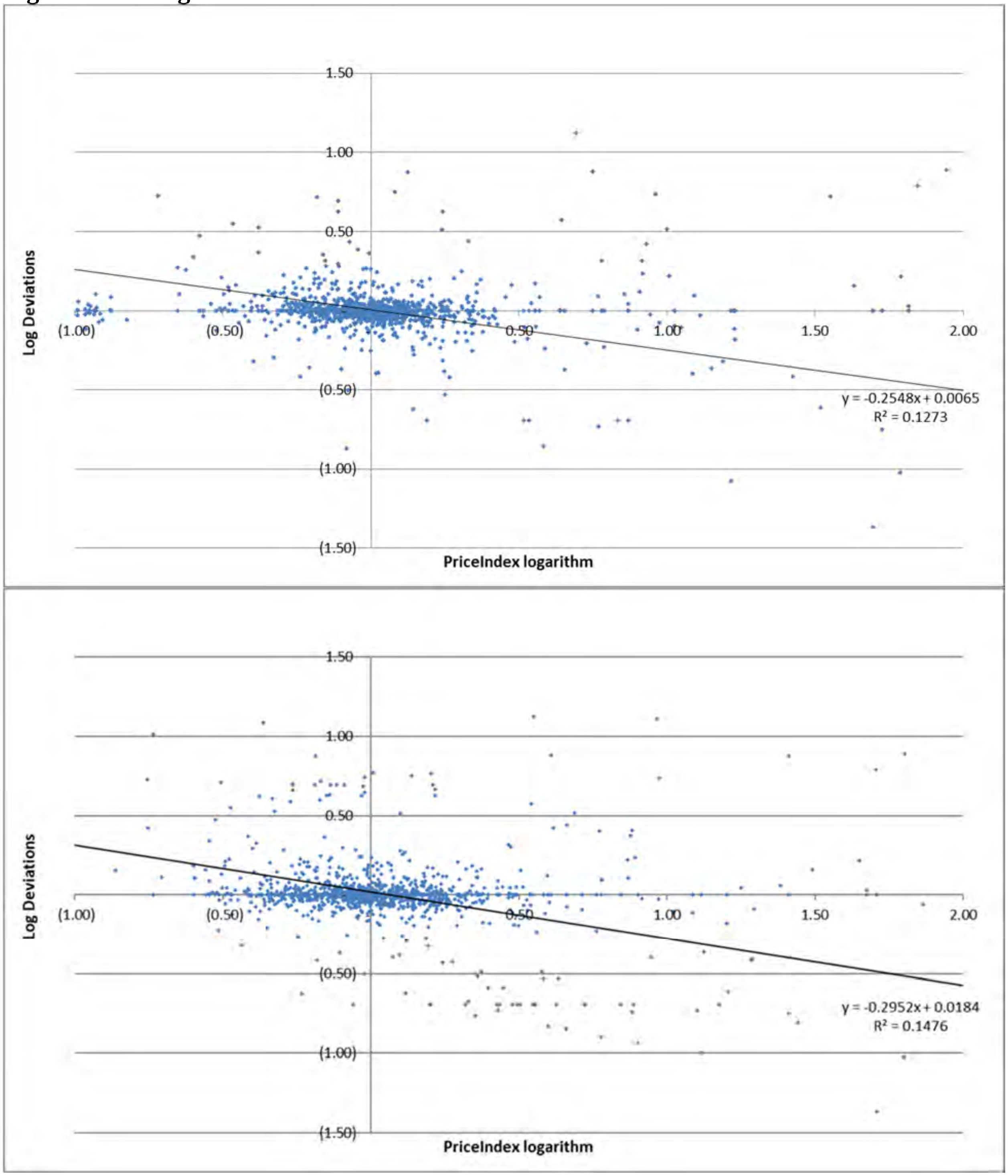
Parameter Estimation – Autoregressive Model

Uncertainty parameters are calculated for each variable by regressing the movement of each region's price index compared to the previous day's index.

Step 1 - Calculate Log Deviation of Price Index
Since gas prices are lognormally distributed, the regression analysis is performed on the natural log of prices and their log deviations. The log deviations are simply the differences between the natural log of one day's price index and the natural log of the previous day's price index.

Step 2 - Perform Regression
The log deviations of price index are regressed against the previous day's logarithm of price index for each season as well as for the entire data set. The following chart shows the log of the price index versus the log deviations for Sumas gas for all seasons and the resulting regression equation:

Figure H.7 – Regression for SUMAS Gas Basin



Step 3 - Interpret the Results

The INTERCEPT of the regression represents the log of the long-run mean. So in this case, the intercept is approximately zero, implying that the long-run mean is equal to one. This is consistent with the way in which the price index is formulated.

The *SLOPE* of the regression is related to the auto correlation and mean reversion rate:

$$auto\ correlation = \emptyset = 1 + slope$$
$$Mean\ Reversion\ Rate\ \ \alpha = \ -\ln(\emptyset)$$

The autocorrelation measures how much of the price shock from the previous time period remains in the next time period. For instance, if the autocorrelation is 0.4 and gas prices yesterday experienced a 10 percent jump over the norm, today's expected price would be 4 percent higher than normal. In addition, today's gas price will experience a shock today that may result in prices higher or lower than this expectation. The mean reversion rate expresses the same thing in a different manner. The higher the mean reversion rate, the faster prices revert to the long-run mean.

The last component of the regression analysis is the *STANDARD ERROR* or *STEYX*. This measures the portion of the price movements not explained by mean reversion and is the estimate of the variable's volatility.

Both the mean reversion rate and volatility calculated with this process are daily parameters and can be applied directly to daily movements in gas prices.

Step 4 - Results
The natural gas price parameters derived through this process are reported in the table below.

Table H.2 - Uncertainty Parameters for Natural Gas

	Winter	Spring	Summer	Fall
KERN OPAL				
Daily Volatility	27.16%	13.44%	13.47%	15.28%
Daily Mean Reversion Rate	0.129	0.304	0.525	0.244
SUMAS				
Daily Volatility	23.66%	22.44%	14.77%	74.31%
Daily Mean Reversion Rate	0.074	0.155	0.405	0.570

Electricity Price Process

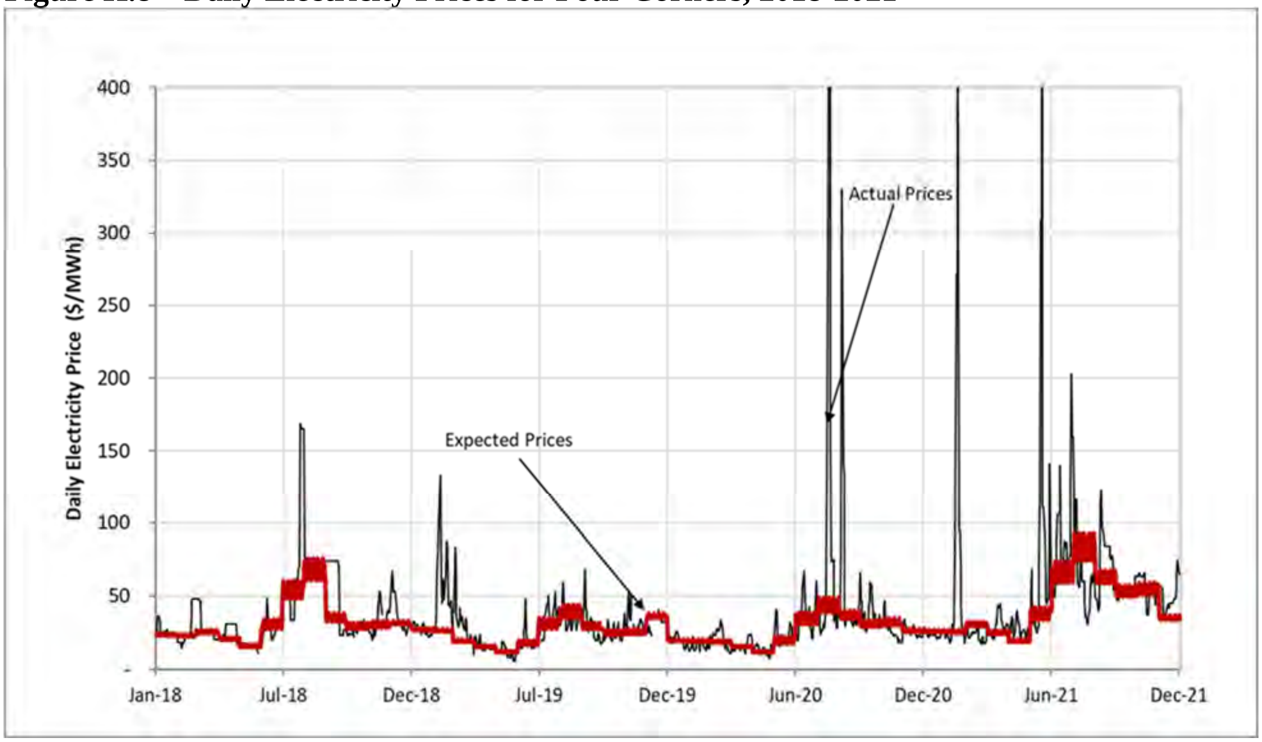
For the most part, electricity prices behave very similarly to natural gas prices. The lognormal distribution is generally a good assumption for electricity. While electricity prices do occasionally go below zero, this is not common enough to be worth using the Normal distribution assumption, and the distribution of electricity prices is often skewed upwards. In fact, even the lognormal assumption is sometimes inadequate for capturing the tail of the electricity price distribution. Like gas prices, electricity price can experience substantial change from one day to the next, so a daily time step should be used.

Basic Data Set:
The electricity price data was organized into a consistent dataset with one price for each region reported for each delivery day, like gas prices. The data covers the 2018 through 2021 period. However, electricity prices are reported for "High Load Level" periods (16 hours for six days a week) and "Low Load Level" periods (eight hours for six days a week and 24 hours on Sunday & NERC holidays). To have a consistent price definition, a composite price, calculated based on 16

hours of peak and eight hours of off-peak prices, is used for Monday through Saturday. The Low Load Level price was used for Sundays since that already reflects the 24-hour price. Missing and duplicate data is handled in a fashion like gas prices. Illiquid delivery point prices are filled using liquid hub prices as reference. Mid-C is the most liquid market in PACW, so missing prices for COB are filled using the latest available spread between COB and Mid-C markets. Similarly, Four Corner prices are filled using Palo Verde prices.

Development of Price Index:
As with gas prices, an electricity price index was developed which accounts for the expected components of price movements. The "expected" electricity price incorporates all three possible adjustments: seasonal median, monthly shape, and weekly shape. For instance, the expected price for January 2, 2018, in the Four Corners region was $24.22/megawatt hours (MWh). This price incorporates the 2018 winter median price of $26.00/MWh times the monthly shape factor for January of 90 percent and the weekday index for Saturday of 98 percent. The following chart shows the Four Corners actual and expected electricity prices over the analysis time period.

Figure H.8 – Daily Electricity Prices for Four Corners, 2018-2021



Electricity Price Uncertainty Parameters
Uncertainty parameters are calculated for each electric region, similar to the process for gas prices. The electricity price parameters derived through this process are reported in the table below.

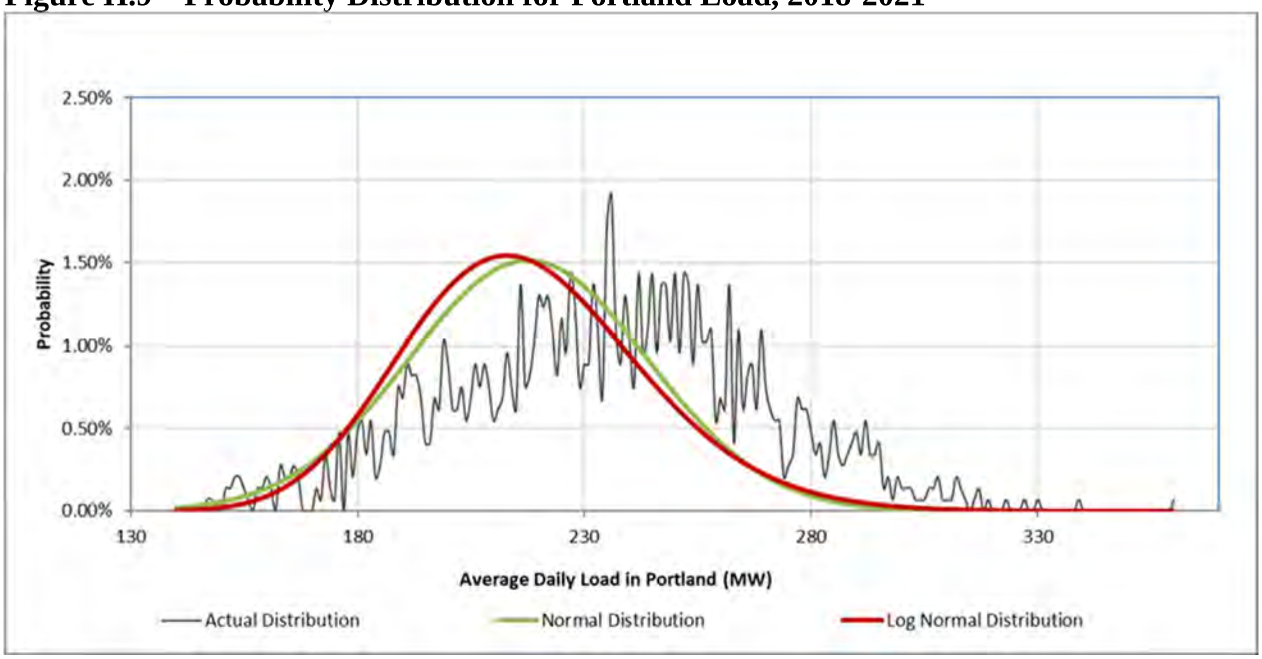
Table H.3 - Uncertainty Parameters for Electricity Regions

	Winter	Spring	Summer	Fall
Four Corners				
Daily Volatility	19.42%	19.26%	31.11%	21.46%
Daily Mean Reversion Rate	0.103	0.216	0.213	0.238
CA-OR Border				
Daily Volatility	19.10%	23.80%	94.62%	18.88%
Daily Mean Reversion Rate	0.101	0.213	1.014	0.297
Mid-Columbia				
Daily Volatility	22.31%	56.40%	39.16%	18.97%
Daily Mean Reversion Rate	0.101	0.477	0.300	0.294
Palo Verde				
Daily Volatility	17.44%	16.45%	28.82%	20.58%
Daily Mean Reversion Rate	0.102	0.199	0.149	0.230

Regional Load Process

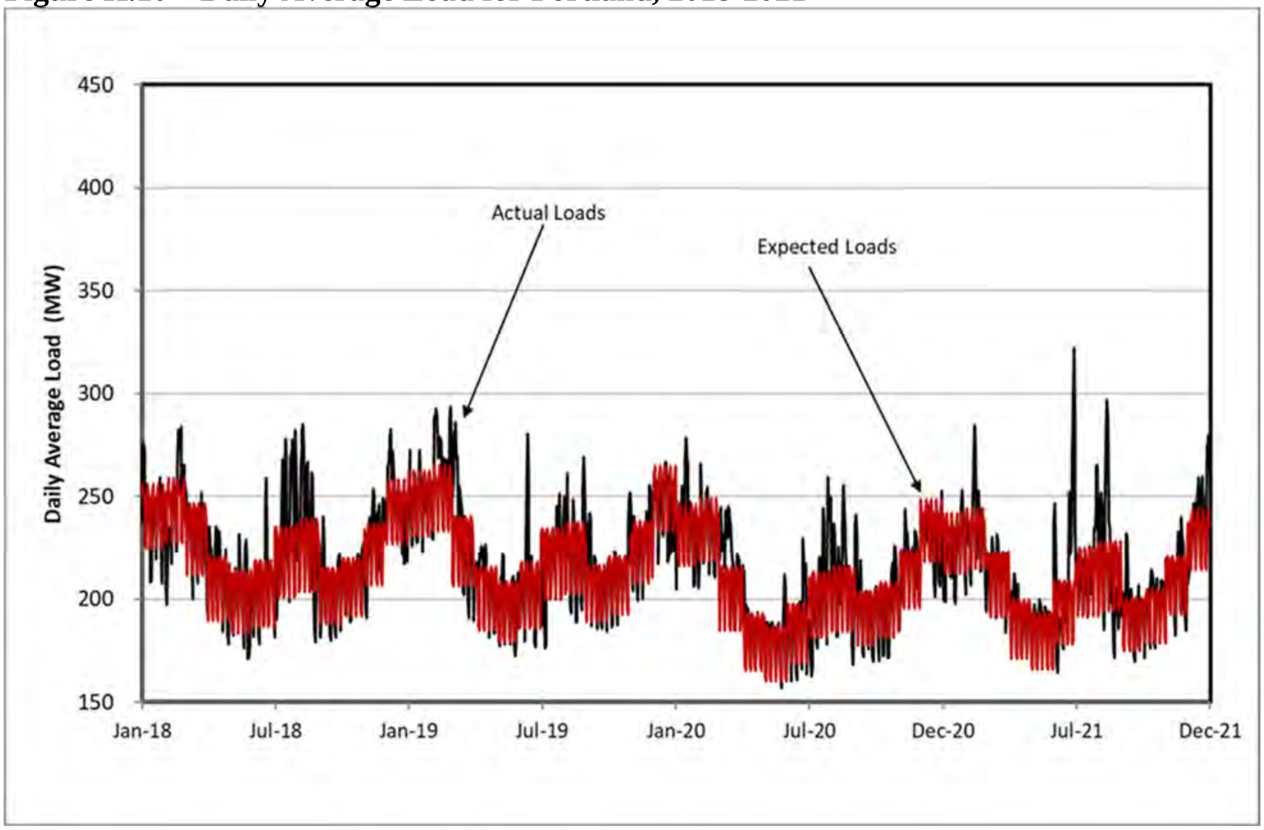
There are only two significant differences between the uncertainty analysis for regional loads and natural gas prices. The distribution of daily loads is somewhat better represented by a normal distribution rather than a lognormal distribution, and similar to electricity prices, loads have a significant expected shape across the week. The chart below shows the distribution of historical load outcomes for the Portland area as well as normal and lognormal distribution functions representing load possibilities. Both distributions do a reasonable job of representing the spread of possible load outcomes, but the tail of the lognormal distribution implies the possibility of higher loads than is supported by the historical data.

Figure H.9 – Probability Distribution for Portland Load, 2018-2021



Development of Load Index:
As with electricity prices, a load index was developed which accounts for the expected components of load movements, incorporating all three possible adjustments. For instance, the expected load for January 2, 2018, in Portland was 275 megawatts (MW). This load incorporates the 2018 winter average load of 245 MW times the monthly shape factor for January of 99 percent and the weekday index for Saturday also of 93 percent. The following chart shows the Portland actual and expected loads over the analysis period.

Figure H.10 – Daily Average Load for Portland, 2018-2021



Load Uncertainty Parameters:
Uncertainty parameters are calculated for each load region, like the process for gas and electricity prices. Since loads are modeled as normally, rather than log-normally distributed, deviations are simply calculated as the difference between the load index and the previous day's index.

The uncertainty parameters for regional loads derived through this process are reported in the table below.

Table H.4 - Uncertainty Parameters for Load Regions

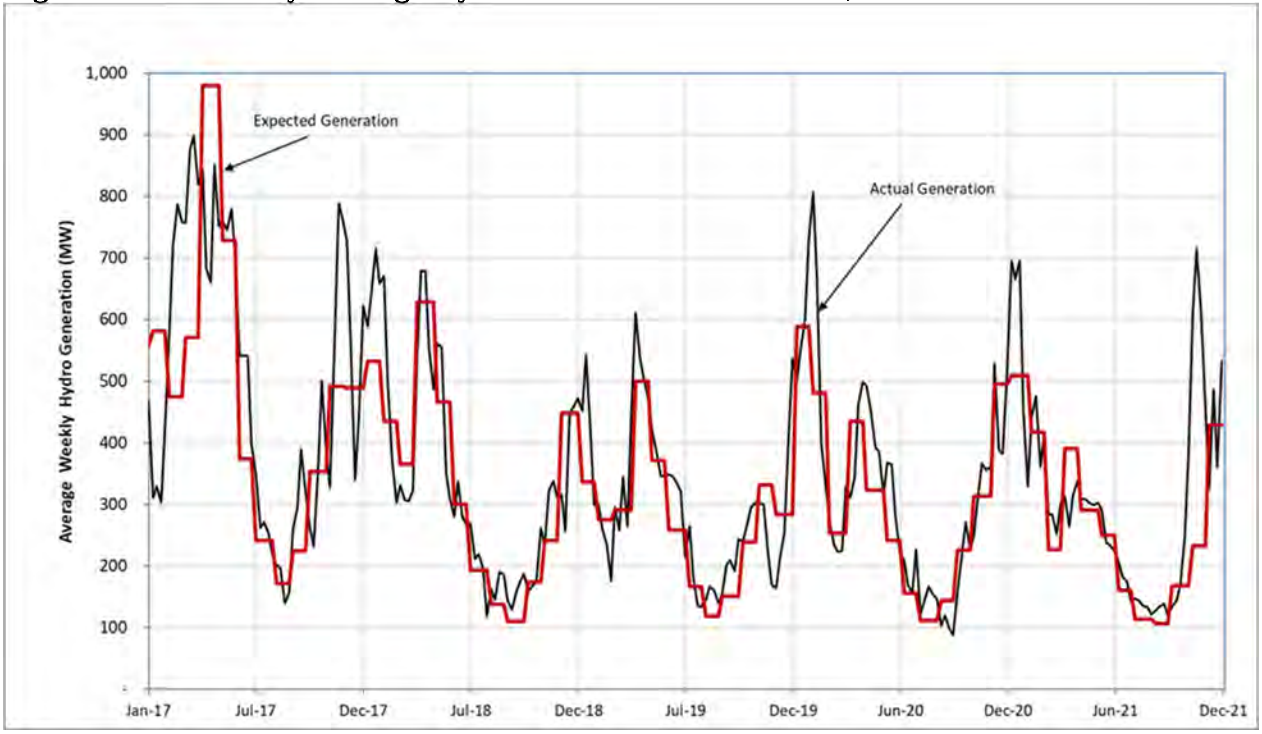
	Winter	Spring	Summer	Fall
California				
Daily Volatility	4.58%	4.15%	4.19%	4.64%
Daily Mean Reversion Rate	0.258	0.153	0.185	0.222
Idaho				
Daily Volatility	3.81%	6.44%	6.11%	4.68%
Daily Mean Reversion Rate	0.263	0.146	0.143	0.128
Portland				
Daily Volatility	4.06%	3.54%	5.95%	3.59%
Daily Mean Reversion Rate	0.252	0.229	0.183	0.365
Oregon Other				
Daily Volatility	4.36%	3.63%	4.55%	4.20%
Daily Mean Reversion Rate	0.261	0.242	0.168	0.253
Utah				
Daily Volatility	2.41%	3.47%	5.41%	3.49%
Daily Mean Reversion Rate	0.380	0.332	0.265	0.234
Washington				
Daily Volatility	5.03%	4.20%	5.37%	4.42%
Daily Mean Reversion Rate	0.171	0.164	0.173	0.213
Wyoming				
Daily Volatility	2.08%	2.08%	2.12%	2.01%
Daily Mean Reversion Rate	0.279	0.109	0.190	0.224

Hydro Generation Process

There are two differences between the uncertainty analysis for hydro generation and natural gas prices. Hydro generation varies on a slower time frame than other variables analyzed. As such, median hydro generation is calculated and analyzed on a weekly, rather than daily, basis. Generation is calculated as the median hourly generation across the 168 hours in a week. The hydro analysis covers the 2017 through 2021 period.

Development of Hydro Index:
A hydro generation index was developed which accounts for the expected components of hydro movements, incorporating seasonal and monthly adjustments. For instance, the expected hydro generation for the week of January 1, 2017, through January 7, 2017 in the Western Region was 467 MW. This generation incorporates the 2017 winter median generation of 515 MW times the monthly shape factor for January of 113 percent. The following chart shows the western hydro actual and expected generation over the analysis period.

Figure H.11 – Weekly Average Hydro Generation in the West, 2017-2021



Hydro Generation Uncertainty Parameters:
Uncertainty parameters are calculated for each hydro region, similar to the process for gas and electricity prices. The uncertainty parameters for hydro generation derived through this process are reported in the table below.

Table H.5 - Uncertainty Parameters for Hydro Generation

	Winter	Spring	Summer	Fall
Weekly Volatility	25.68%	20.11%	19.48%	27.59%
Weekly Mean Reversion Rate	0.68	0.77	1.80	0.36

Short-term Correlation Estimation

Correlation is a measure of how much the random component of variables tend to move together. After the uncertainty analysis has been performed, the process for estimating correlations is relatively straight-forward.

Step 1 - Calculate Residual Errors
Calculate the residual errors of the regression analysis for all the variables. The residual error represents the random portion of the deviation not explained by mean reversion. It is calculated for each period as the difference between the actual value and the value predicted by the linear regression equation:

$$Error = Actual\ Deviation - (Slope * Previous\ Deviation + Intercept)$$

All of the residual errors are compiled by delivery date.

Step 2 - Calculate Correlations
Correlate the residual errors of each pair of variables:

$$Correlation(X,Y) = \frac{\sum_i^n[(x_i - x_{avg.}) * (y_i - y_{avg.})]}{\sqrt{\sum_i^n(x_i - x_{avg.})^2 * \sum_i^n(y_i - y_{avg.})^2}}$$

There are a few things to note about the correlation calculations. First, correlation data must always be organized so that the same period is being compared for both variables. For instance, weekly hydro deviations cannot be compared to daily gas price deviations. Thus, a daily regression analysis was performed for the hydro variables.

Also, note that what is being correlated are the residual errors of the regression – only the uncertain portion of the variable movements. Variables may exhibit similar expected shapes – both loads and electricity prices are higher during the week than on the weekend. This coincidence is captured in the expected weekly shapes input into the planning model. The correlation calculated here captures the extent to which the shocks experienced by two different variables tend to have similar direction and magnitude. The resulting short-term correlations by season are reported below.

Table H.6 - Short-term Winter Correlations

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	69%	40%	30%	34%	45%	1%	-5%	10%	1%	2%	5%	-1%	-12%
SUMAS	69%	100%	20%	26%	29%	24%	7%	6%	11%	6%	1%	13%	3%	-16%
4C	40%	20%	100%	58%	52%	89%	13%	2%	8%	15%	20%	17%	9%	1%
COB	30%	26%	58%	100%	72%	57%	18%	1%	9%	22%	12%	28%	8%	-2%
Mid-C	34%	29%	52%	72%	100%	56%	14%	0%	19%	26%	12%	31%	5%	-3%
PV	45%	24%	89%	57%	56%	100%	8%	-1%	4%	9%	14%	13%	7%	-3%
CA	1%	7%	13%	18%	14%	8%	100%	16%	46%	78%	28%	45%	17%	10%
ID	-5%	6%	2%	1%	0%	-1%	16%	100%	24%	26%	35%	28%	23%	9%
Portland	10%	11%	8%	9%	19%	4%	46%	24%	100%	69%	40%	64%	32%	10%
OR Other	1%	6%	15%	22%	26%	9%	78%	26%	69%	100%	40%	67%	25%	16%
UT	2%	1%	20%	12%	12%	14%	28%	35%	40%	40%	100%	33%	50%	4%
WA	5%	13%	17%	28%	31%	13%	45%	28%	64%	67%	33%	100%	28%	15%
WY	-1%	3%	9%	8%	5%	7%	17%	23%	32%	25%	50%	28%	100%	0%
Hydro	-12%	-16%	1%	-2%	-3%	-3%	10%	9%	10%	16%	4%	15%	0%	100%

Deviation events that impact one part of PacifiCorp's system do not necessarily affect other parts of the system, due to its geographic diversity and transmission constraints. The correlation between these different deviations can be low if the deviations are caused by different drivers. An example from the winter season is the nine percent correlation between the Southeast Idaho load area, which is driven by weather events in PacifiCorp's PACE balancing area, and Hydro, which is predominantly driven by weather events in PacifiCorp's PACW balancing area, the unit commitment stack and unplanned unit outages.

Table H.7 - Short-term Spring Correlations

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	62%	16%	13%	14%	13%	5%	19%	8%	14%	13%	10%	9%	3%
SUMAS	62%	100%	15%	19%	14%	8%	-3%	17%	10%	10%	17%	16%	10%	-5%
4C	16%	15%	100%	38%	41%	72%	18%	10%	26%	27%	20%	22%	5%	5%
COB	13%	19%	38%	100%	58%	28%	18%	1%	22%	26%	11%	28%	6%	12%
Mid-C	14%	14%	41%	58%	100%	27%	19%	0%	20%	21%	3%	29%	3%	7%
PV	13%	8%	72%	28%	27%	100%	16%	7%	22%	18%	15%	14%	9%	1%
CA	5%	-3%	18%	18%	19%	16%	100%	10%	43%	66%	17%	42%	14%	-4%
ID	19%	17%	10%	1%	0%	7%	10%	100%	-4%	6%	50%	11%	14%	3%
Portland	8%	10%	26%	22%	20%	22%	43%	-4%	100%	70%	13%	57%	24%	-11%
OR Other	14%	10%	27%	26%	21%	18%	66%	6%	70%	100%	19%	65%	29%	-3%
UT	13%	17%	20%	11%	3%	15%	17%	50%	13%	19%	100%	22%	27%	-14%
WA	10%	16%	22%	28%	29%	14%	42%	11%	57%	65%	22%	100%	15%	-2%
WY	9%	10%	5%	6%	3%	9%	14%	14%	24%	29%	27%	15%	100%	-17%
Hydro	3%	-5%	5%	12%	7%	1%	-4%	3%	-11%	-3%	-14%	-2%	-17%	100%

Similarly, the spring season shows a very low correlation of 14 percent between the Northern California and Wyoming loads, which are driven by different local weather deviations and different customer types. Wyoming loads are mostly driven by large industrial customers, whose loads are relatively flat across the year.

Table H.8 - Short-term Summer Correlations

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	81%	13%	11%	23%	13%	1%	-4%	8%	4%	-2%	11%	-5%	-1%
SUMAS	81%	100%	11%	6%	21%	7%	1%	-1%	8%	3%	-1%	8%	-4%	1%
4C	13%	11%	100%	22%	40%	78%	19%	6%	26%	22%	26%	21%	10%	-3%
COB	11%	6%	22%	100%	61%	29%	14%	4%	20%	20%	20%	27%	5%	-4%
Mid-C	23%	21%	40%	61%	100%	47%	18%	-2%	39%	34%	5%	30%	0%	-3%
PV	13%	7%	78%	29%	47%	100%	21%	10%	28%	25%	26%	26%	13%	-1%
CA	1%	1%	19%	14%	18%	21%	100%	39%	44%	73%	30%	60%	9%	-9%
ID	-4%	-1%	6%	4%	-2%	10%	39%	100%	6%	19%	49%	17%	31%	0%
Portland	8%	8%	26%	20%	39%	28%	44%	6%	100%	77%	13%	62%	-4%	-1%
OR Other	4%	3%	22%	20%	34%	25%	73%	19%	77%	100%	18%	82%	3%	-2%
UT	-2%	-1%	26%	20%	5%	26%	30%	49%	13%	18%	100%	18%	43%	-5%
WA	11%	8%	21%	27%	30%	26%	60%	17%	62%	82%	18%	100%	5%	-6%
WY	-5%	-4%	10%	5%	0%	13%	9%	31%	-4%	3%	43%	5%	100%	-4%
Hydro	-1%	1%	-3%	-4%	-3%	-1%	-9%	0%	-1%	-2%	-5%	-6%	-4%	100%

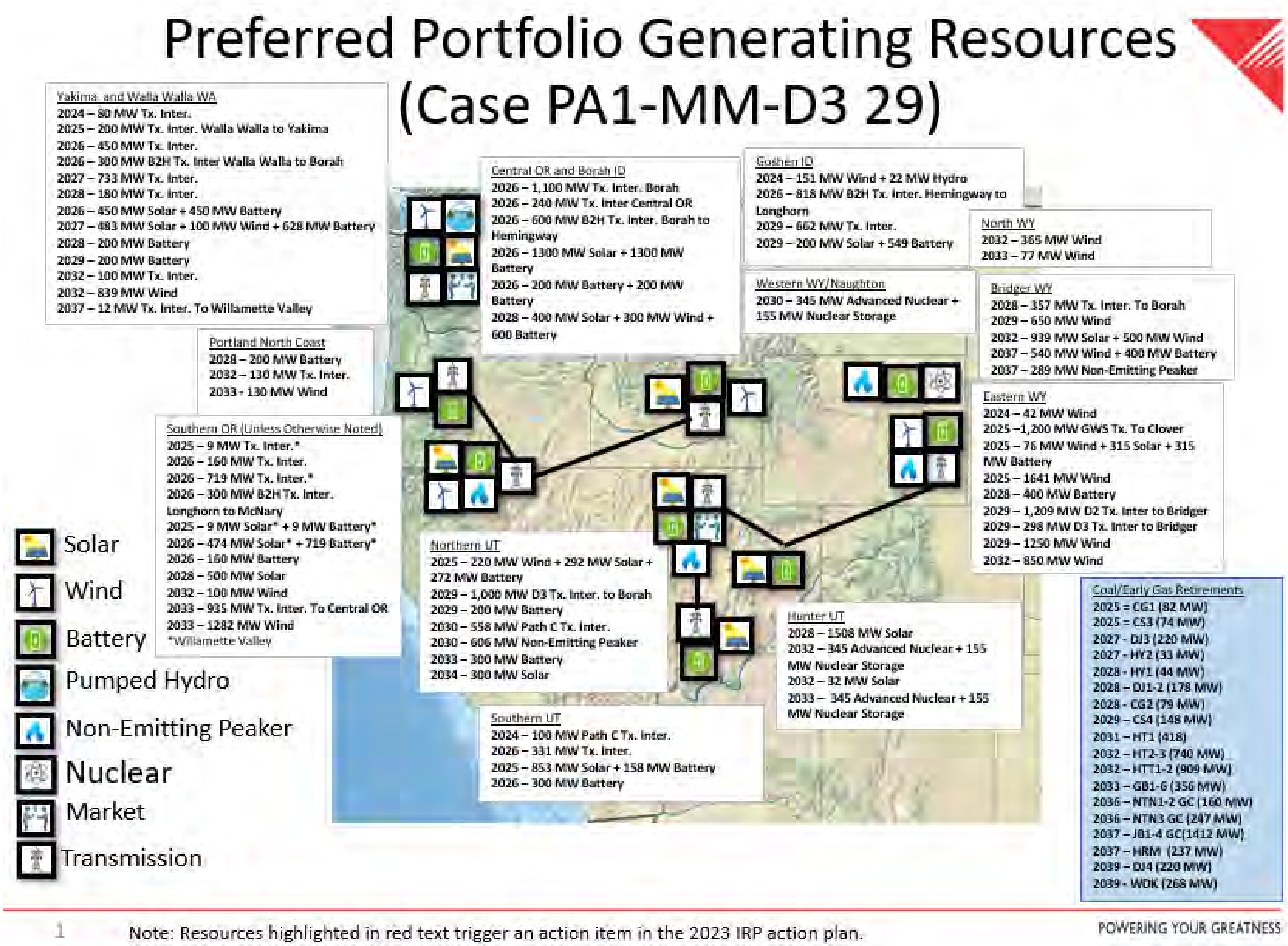
In the summer season, 13 percent correlation has been observed between the deviations of Kern-Opal gas prices and Palo Verde power prices. Palo Verde prices are driven by a resource mix of southwest nuclear operations and gas unit dispatch based off SoCal gas prices. The operations of gas storage facilities and physical planned and unplanned maintenance of Kern-Opal and SoCal pipelines are independent of each other.

Table H.9 - Short-term Fall Correlations

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	20%	5%	13%	12%	3%	19%	-16%	9%	17%	-3%	9%	9%	1%
SUMAS	20%	100%	-1%	-9%	-3%	3%	5%	-3%	4%	5%	-3%	1%	6%	7%
4C	5%	-1%	100%	30%	26%	77%	13%	-3%	1%	8%	24%	10%	-7%	-15%
COB	13%	-9%	30%	100%	71%	37%	25%	-1%	28%	26%	13%	27%	11%	-19%
Mid-C	12%	-3%	26%	71%	100%	34%	23%	-3%	38%	34%	13%	32%	11%	-10%
PV	3%	3%	77%	37%	34%	100%	14%	-1%	2%	7%	17%	6%	-6%	-14%
CA	19%	5%	13%	25%	23%	14%	100%	27%	55%	80%	36%	60%	19%	8%
ID	-16%	-3%	-3%	-1%	-3%	-1%	27%	100%	26%	22%	43%	28%	22%	8%
Portland	9%	4%	1%	28%	38%	2%	55%	26%	100%	78%	37%	69%	33%	-1%
OR Other	17%	5%	8%	26%	34%	7%	80%	22%	78%	100%	41%	77%	32%	6%
UT	-3%	-3%	24%	13%	13%	17%	36%	43%	37%	41%	100%	43%	35%	1%
WA	9%	1%	10%	27%	32%	6%	60%	28%	69%	77%	43%	100%	34%	8%
WY	9%	6%	-7%	11%	11%	-6%	19%	22%	33%	32%	35%	34%	100%	3%
Hydro	1%	7%	-15%	-19%	-10%	-14%	8%	8%	-1%	6%	1%	8%	3%	100%

In the fall, a low correlation of 11 percent has been observed between Mid-C market price deviations and Wyoming load deviations. Market deviations are due to deviations in northwest weather patterns and resource mix while Wyoming loads are mostly dictated by planned or unplanned outages of industrial customer class.

Appendix I – Capacity Expansion Results



P10-Offshore Wind

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	-	289	-	-	-	-	-	895
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,683	1,459	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	500	-	-	-	-	-	8,210
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	987	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	166	195	231	52	41	52	52	52	52	52	52	52	29	32	360
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	547	535	587	158	63	47	50	61	33	85	111	163	208	198	584
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,729**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**3,897**	**1,965**	**1,505**	**4,059**	**889**	**228**	**271**	**390**	**1,591**	**(1,130)**	**352**	**(195)**	**376**	**656**	

W-10 SC CETA

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429	4,977
DSM - Demand Response	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-	930
Renewable - Wind	-	194	1,717	-	-	457	500	120	-	6,486	3,607	-	-	-	-	-	-	-	-	-	13,081
Renewable - Utility Solar	-	-	1,469	1,600	-	2,589	1,298	120	108	600	-	841	-	-	-	-	-	-	-	-	8,625
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	-	1,979	1,647	-	-	600	-	-	-	-	1,207	-	-	-	-	-	7,987
Renewable - Battery (Long Duration)	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-	1,184
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	963	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	148
Front Office Transactions - Winter	1,572	1,745	1,383	805	940	474	368	506	613	176	171	57	38	38	129	125	127	121	160	165	486
Front Office Transactions - Summer	1,656	1,869	1,699	1,769	1,854	630	571	572	595	95	6	-	-	-	-	-	-	-	-	-	566
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-	(1,840)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,070)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	-	(237)	-	-	(247)	(237)	-	-	(64)	-	(657)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,610**	**5,045**	**8,635**	**6,045**	**3,150**	**6,581**	**4,328**	**1,935**	**1,999**	**5,792**	**4,444**	**1,331**	**203**	**326**	**2,723**	**(414)**	**316**	**(293)**	**254**	**594**	

S-08 New Load FlatLoad Increase

Summary Portfolio Capacity by Resource Type and Year, Installed MW	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	881	-	-	345	289	-	-	-	-	-	2,121
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	3,359	-	-	-	540	-	-	-	-	-	11,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	1,600	300	-	-	-	-	-	-	-	-	9,455
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	1,750	-	-	-	200	-	-	-	-	-	9,510
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	899	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	145
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	166	195	231	52	27	27	27	27	37	38	38	39	9	10	350
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	547	535	587	158	47	18	26	45	30	33	88	107	100	148	565
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,641**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**3,897**	**1,965**	**1,505**	**4,159**	**6,840**	**174**	**222**	**694**	**1,273**	**(1,196)**	**315**	**(264)**	**248**	**584**	

P11-Max NG

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	1,044	-	-	-	-	500	-	-	522	-	(1,044)	1,022
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	283	-	-	-	-	-	283
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	166	279	281	52	41	52	52	52	52	52	52	52	47	38	368
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	547	598	595	195	163	158	170	191	132	179	281	170	262	303	639
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**3,897**	**1,006**	**1,563**	**4,740**	**389**	**339**	**391**	**520**	**1,884**	**(1,036)**	**522**	**334**	**448**	**(277)**	

P15-No GWS

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,954
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	296	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-	4,521
Renewable - Utility Solar	-	-	1,469	2,224	483	2,307	600	-	200	972	-	300	-	-	-	-	-	-	-	-	8,555
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,629	628	2,500	1,349	-	-	800	150	-	-	-	200	-	-	-	-	-	9,210
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-	950
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-	2,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,816	977	1,085	950	974	919	938	440	315	316	316	316	422	565	657	679	737	839	834
Front Office Transactions - Summer	1,683	1,874	1,836	1,866	1,826	633	647	632	632	408	196	195	191	191	120	179	207	235	312	369	712
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	(330)	-	-	-	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	(268)	-	-	-	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(1,783)	-	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**7,782**	**7,969**	**4,469**	**6,737**	**3,505**	**2,786**	**2,457**	**5,763**	**1,119**	**640**	**676**	**1,129**	**197**	**890**	**1,053**	**1,102**	**1,188**	**1,634**	

P16-No B2H

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	-	1,900	400	-	2,783	959	-	-	-	540	-	-	-	-	-	8,813
Renewable - Utility Solar	-	-	1,469	2,524	483	1,507	600	-	-	972	600	300	-	-	-	-	-	-	-	-	8,455
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	1,352	1,900	1,149	-	-	-	750	-	-	-	200	-	-	-	-	-	9,234
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	553	556	539	170	177	195	52	41	52	52	52	52	52	52	65	47	106	363
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	622	558	516	585	147	50	47	47	47	34	51	129	156	204	205	583
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**8,443**	**7,803**	**4,373**	**4,615**	**4,312**	**2,328**	**1,467**	**4,148**	**1,576**	**228**	**268**	**721**	**1,292**	**(1,164)**	**370**	**(189)**	**390**	**737**	

P-MN

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	-	-	-	303	578	345	-	-	-	-	-	1,226
DSM - Energy Efficiency	123	220	259	198	217	221	243	259	637	105	160	170	161	288	586	164	170	165	139	412	4,897
DSM - Demand Response	72	39	152	99	126	94	27	13	35	-	-	-	-	-	1	228	19	19	-	-	924
Renewable - Wind	-	194	1,717	-	-	-	500	-	-	6,025	3,565	-	450	-	-	-	-	-	-	-	12,451
Renewable - Utility Solar	-	-	1,469	1,600	-	2,470	1,298	-	254	941	-	-	-	-	600	-	-	-	-	-	8,632
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	-	2,304	1,647	-	-	600	-	-	-	-	2,356	-	-	-	-	-	9,461
Renewable - Battery (Long Duration)	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	963	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	148
Front Office Transactions - Winter	1,640	1,781	1,405	766	831	635	624	624	667	254	65	90	51	69	63	179	245	258	168	182	530
Front Office Transactions - Summer	1,683	1,874	1,764	1,835	1,966	650	617	620	636	47	-	4	-	-	-	-	-	-	-	1	585
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	340	(354)	-	-	-	-	(160)	(210)	(699)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	(64)	-	(657
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,705**	**5,086**	**8,720**	**6,056**	**3,148**	**6,521**	**4,628**	**1,509**	**1,875**	**6,905**	**3,790**	**(92)**	**965**	**775**	**3,494**	**(365)**	**434**	**(156)**	**243**	**595**	

P-LN

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	303	-	-	-	-	1,240	-	-	-	-	-	1,543
DSM - Energy Efficiency	123	220	259	197	216	219	240	258	637	103	160	170	161	281	586	163	170	165	139	412	4,879
DSM - Demand Response	72	39	143	38	161	120	33	16	33	-	-	-	51	-	-	170	19	19	-	-	914
Renewable - Wind	-	194	1,717	-	-	-	500	-	11	5,477	1,821	-	-	-	-	-	-	-	-	-	9,720
Renewable - Utility Solar	-	-	1,469	1,600	-	2,519	1,298	-	288	241	-	-	-	-	1,400	-	-	-	-	-	8,815
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	160	2,008	1,647	-	-	-	400	-	-	-	2,560	-	-	-	-	-	9,329
Renewable - Battery (Long Duration)	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-	800
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,572	1,745	1,187	776	822	718	620	726	757	108	78	69	78	69	87	72	103	181	158	160	504
Front Office Transactions - Summer	1,656	1,869	1,665	2,003	2,040	660	620	596	591	66	70	79	74	72	10	38	71	78	59	30	617
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	(811)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	-	-	-	(2,067)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	598	-	-	699	-	(330)	-	-	-	-	(370)	(1,413)	-	(268)	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	(598)	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(2,368)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	-	(237)	-	-	(247)	(237)	-	-	(64)	-	(657)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,647**	**5,045**	**8,394**	**6,172**	**3,407**	**6,591**	**4,630**	**1,948**	**2,317**	**4,782**	**2,529**	**81**	**364**	**422**	**5,466**	**(1,207)**	**363**	**175**	**292**	**602**	

P-SC

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																					
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429	4,977
DSM - Demand Response	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-	930
Renewable - Wind	-	194	1,717	-	-	457	500	-	-	6,486	3,607	-	-	-	-	-	-	-	-	-	12,961
Renewable - Utility Solar	-	-	1,469	1,600	-	2,589	1,298	-	108	600	-	841	-	-	-	-	-	-	-	-	8,505
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	-	1,979	1,647	-	-	600	-	-	-	-	1,207	-	-	-	-	-	7,987
Renewable - Battery (Long Duration)	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-	1,184
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	930	999	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	146
Front Office Transactions - Winter	1,572	1,745	1,383	805	940	474	368	520	626	184	171	57	41	39	148	126	128	121	164	169	489
Front Office Transactions - Summer	1,656	1,869	1,699	1,769	1,854	630	571	578	595	118	10	-	-	-	-	-	-	-	-	-	567
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-	(1,840)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,070)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	-	(237)	-	-	(247)	(237)	-	-	(64)	-	(657)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,577**	**5,044**	**8,635**	**6,045**	**3,150**	**6,581**	**4,328**	**1,715**	**2,012**	**5,823**	**4,448**	**1,331**	**206**	**327**	**2,742**	**(413)**	**317**	**(293)**	**258**	**598**	

P-HH

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	-	-	-	-	-	951	-	-	-	-	-	951
DSM - Energy Efficiency	123	220	259	210	229	234	255	266	675	116	161	185	162	289	594	165	187	176	172	671	5,349
DSM - Demand Response	72	39	154	119	117	81	26	-	37	5	13	12	26	-	-	239	22	19	-	-	981
Renewable - Wind	-	194	1,717	-	-	174	500	-	-	7,922	2,321	-	-	-	-	-	-	-	-	-	12,828
Renewable - Utility Solar	-	-	1,469	1,600	-	3,006	1,298	-	4	1,288	241	-	-	-	-	-	-	-	-	-	8,906
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	-	2,599	1,647	-	-	600	-	-	-	-	1,541	-	-	-	-	-	8,941
Renewable - Battery (Long Duration)	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-	800
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	500	-	-	-	-	-	2,000
Front Office - Selected Markets	993	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,572	1,745	1,254	864	910	556	551	511	613	101	31	31	31	37	21	65	117	175	131	167	474
Front Office Transactions - Summer	1,656	1,869	1,656	1,783	1,955	622	575	568	587	11	11	23	11	11	7	11	11	11	3	3	569
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	(237)	(237)	-	-	(247)	-	-	-	(500)	-	(1,093)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,640**	**5,045**	**8,463**	**6,134**	**3,211**	**7,627**	**4,524**	**1,697**	**1,916**	**8,857**	**2,541**	**14**	**230**	**337**	**3,197**	**(933)**	**337**	**(217)**	**(194)**	**841**	

P14-All GW

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,195	1,453	696	482	607	518	166	195	231	52	41	52	52	52	52	52	52	62	46	85	307
Front Office Transactions - Summer	1,556	1,709	1,417	1,547	1,524	582	547	535	587	159	83	53	66	65	48	120	132	182	231	252	570
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,170**	**4,593**	**7,884**	**7,754**	**3,689**	**5,254**	**3,897**	**1,965**	**1,505**	**4,160**	**809**	**234**	**287**	**739**	**1,306**	**(1,095)**	**373**	**(166)**	**416**	**763**	

P13-All EE

Summary Portfolio Capacity by Resource Type and Year, Installed MW	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	289	330	334	392	457	1,016	215	301	283	292	457	816	230	253	241	343	1,231	8,082
DSM - Demand Response	72	39	152	109	119	91	29	13	35	-	1	-	2	-	4	265	70	20	-	778	1,799
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	995	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	552	529	481	124	164	173	52	41	52	52	41	52	52	52	52	29	21	349
Front Office Transactions - Summer	1,683	1,874	1,637	1,515	1,516	573	529	480	564	150	53	47	47	47	30	35	102	109	124	141	563
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,081**	**8,443**	**7,884**	**3,705**	**5,333**	**3,995**	**2,072**	**1,788**	**4,254**	**906**	**326**	**393**	**890**	**1,514**	**(1,068)**	**477**	**(176)**	**496**	**2,171**	

P12-RET Coal 30 NG 40

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	1,790	-	-	-	-	-	2,741
DSM - Energy Efficiency	123	954	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	5,687
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	676	-	-	-	-	-	9,249
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	1,323	-	-	-	-	(196)	8,833
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,702	758	296	413	298	79	111	153	52	52	52	52	52	458	549	584	841	876	933	498
Front Office Transactions - Summer	1,683	1,783	1,382	1,138	1,073	530	346	375	423	149	89	66	66	75	508	481	498	545	585	590	619
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	(811)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	(450)	-	-	-	-	(418)	(1,199)	-	-	-	-	-	-	-	-	-	(2,067)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	598	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	(598)	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	(598)	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(2,368)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(2,781)	-	-	-	-	-	(2,890)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,650**	**7,711**	**7,159**	**2,790**	**4,982**	**3,609**	**1,721**	**1,263**	**3,650**	**776**	**247**	**287**	**749**	**2,398**	**0**	**1,271**	**976**	**1,600**	**1,753**	

P08-No D3-D2

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,954
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-	6,162
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	800	150	-	-	-	200	-	-	-	-	-	8,710
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-	950
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-	2,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	525	632	594	613	236	78	107	79	105	80	160	249	374	446	547	519
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	607	608	631	353	192	186	191	191	97	139	136	196	268	269	645
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**8,443**	**7,804**	**3,646**	**5,265**	**2,523**	**2,437**	**1,931**	**5,504**	**878**	**422**	**439**	**918**	**1,843**	**(968)**	**574**	**160**	**853**	**1,242**	

P07-D3-D2 32

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	-	-	-	6,165	1,755	-	-	-	-	-	-	-	-	-	10,451
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	(196)	7,710
Renewable - Battery (Long Duration)	-	-	600	-	-	-	-	-	-	-	150	-	(600)	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	940	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	147
Front Office Transactions - Winter	1,640	1,781	962	448	625	533	636	592	610	52	41	52	52	52	52	52	52	64	47	86	421
Front Office Transactions - Summer	1,683	1,874	1,405	1,522	1,506	570	603	608	631	143	47	18	18	20	30	38	113	134	141	193	565
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,682**	**5,086**	**8,538**	**7,695**	**3,885**	**5,257**	**2,523**	**2,435**	**1,928**	**7,526**	**1,169**	**199**	**(361)**	**694**	**748**	**(1,177)**	**354**	**(212)**	**327**	**509**	

P03-Hunter3-SCR

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	198	216	220	240	258	637	105	149	170	161	288	586	163	186	176	143	429	4,927
DSM - Demand Response	72	53	167	105	111	90	31	13	35	-	-	2	-	-	-	225	19	38	-	-	961
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,832	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,780
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,778	1,025	552	552	528	172	197	237	52	41	52	52	52	52	52	52	65	47	98	365
Front Office Transactions - Summer	1,683	1,872	1,629	1,524	1,535	586	554	547	587	165	88	57	66	65	48	120	132	186	235	257	597
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,178)	-	-	-	-	-	-	(268)	-	-	(1,864)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,095**	**8,440**	**7,798**	**3,625**	**5,203**	**3,918**	**1,973**	**1,496**	**4,159**	**1,259**	**225**	**279**	**750**	**1,298**	**(1,090)**	**389**	**(133)**	**425**	**784**	

P06-No Forward Tech

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429	4,917
DSM - Demand Response	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-	1,005
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	600	-	-	-	-	-	8,455
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-	8,310
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	300	450	-	-	-	200	-	-	-	-	-	950
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Front Office - Selected Markets	903	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	145
Front Office Transactions - Winter	1,640	1,752	964	551	556	523	165	279	268	65	52	52	52	52	52	52	57	326	365	358	409
Front Office Transactions - Summer	1,683	1,850	1,561	1,521	1,534	585	547	585	595	362	200	191	196	215	173	222	293	408	480	503	685
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,645**	**5,214**	**8,343**	**7,711**	**3,604**	**5,249**	**3,916**	**1,591**	**1,548**	**4,370**	**923**	**360**	**485**	**900**	**1,979**	**(1,090)**	**554**	**351**	**986**	**1,290**	

P05-No NUC

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	Installed Capacity, MW																				
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	895	-	303	303	-	-	345	289	-	-	-	-	-	2,135
DSM - Energy Efficiency	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429	4,917
DSM - Demand Response	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-	1,005
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-	8,310
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Front Office - Selected Markets	963	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	148
Front Office Transactions - Winter	1,640	1,752	964	551	556	523	165	279	267	64	52	52	52	52	52	55	106	348	384	412	416
Front Office Transactions - Summer	1,683	1,850	1,561	1,521	1,534	585	547	583	595	362	200	191	196	215	217	270	370	461	493	582	701
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,705**	**5,214**	**8,343**	**7,711**	**3,604**	**5,249**	**3,916**	**1,878**	**1,547**	**4,372**	**926**	**360**	**485**	**900**	**1,423**	**(1,039)**	**680**	**426**	**1,018**	**1,423**	

P04-Huntington RET28

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	Installed Capacity, MW																				Total
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	208	228	219	240	258	637	109	161	171	161	288	542	163	184	176	141	428	4,916
DSM - Demand Response	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-	1,001
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	2,300	1,149	-	-	-	-	-	-	-	100	-	-	-	-	-	8,060
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	200
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,752	964	551	556	509	163	195	233	52	41	52	52	52	52	52	52	65	47	95	359
Front Office Transactions - Summer	1,683	1,850	1,561	1,521	1,533	586	546	532	587	156	78	51	64	62	48	120	132	177	231	248	588
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	(459)	-	-	-	(418)	(1,190)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,214**	**8,343**	**7,711**	**3,605**	**5,173**	**3,913**	**1,952**	**1,468**	**4,154**	**949**	**220**	**385**	**747**	**1,154**	**(1,190)**	**388**	**(141)**	**419**	**771**	

P02-JB3-4 EOL

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	208	228	219	241	259	637	116	163	172	163	288	542	163	183	175	141	428	4,928
DSM - Demand Response	72	220	193	6	83	61	41	10	8	-	-	-	117	-	-	121	21	20	-	-	973
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,752	969	551	555	523	164	195	233	52	41	52	52	52	52	52	52	65	47	92	360
Front Office Transactions - Summer	1,683	1,850	1,561	1,521	1,533	585	546	532	587	155	78	52	65	65	48	120	132	179	231	247	589
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	(699)	-	(330)	-	-	(1,840)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,070)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,214**	**8,342**	**7,705**	**3,610**	**5,242**	**3,913**	**1,954**	**1,465**	**4,160**	**792**	**220**	**397**	**750**	**1,254**	**(1,194)**	**388**	**(159)**	**419**	**767**	

P19-Cluster West

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	2,406	200	-	-	972	-	300	-	-	-	-	-	-	-	-	8,354
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	2,399	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	8,409
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	483	152	184	213	52	41	52	52	52	52	52	52	52	46	65	358
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	567	476	419	539	150	50	46	50	50	30	45	121	146	189	193	566
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**8,443**	**7,803**	**3,646**	**6,202**	**3,812**	**1,838**	**1,439**	**4,151**	**776**	**227**	**271**	**724**	**1,288**	**(1,170)**	**362**	**(212)**	**374**	**684**	

P18-Cluster East

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	Installed Capacity, MW																				Total
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	2,373	-	-	972	-	300	-	-	-	-	-	-	-	-	10,028
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	3,322	-	-	-	150	-	-	-	200	-	-	-	-	-	10,083
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	66	84	128	52	41	51	41	41	52	52	52	52	29	27	343
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	303	328	374	58	18	16	-	-	-	3	14	30	40	36	503
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,742**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**7,899**	**1,647**	**1,189**	**4,059**	**744**	**196**	**210**	**663**	**1,258**	**(1,212)**	**255**	**(328)**	**208**	**489**	

P01-JB3-4 GC

Summary Portfolio Capacity by Resource Type and Year, Installed MW	Installed Capacity, MW																				
Resource	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	208	228	219	240	258	637	115	161	171	161	288	542	163	184	176	141	428	4,922
DSM - Demand Response	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-	1,001
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	987	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149
Front Office Transactions - Winter	1,640	1,752	964	551	555	523	164	195	233	52	41	52	52	52	52	52	52	65	47	94	359
Front Office Transactions - Summer	1,683	1,850	1,561	1,521	1,533	585	546	532	587	156	78	52	66	65	48	120	132	179	231	247	589
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	1,069	-	-	-	-	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(1,056)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,729**	**5,214**	**8,343**	**7,711**	**3,604**	**5,245**	**3,914**	**1,952**	**1,468**	**4,160**	**790**	**221**	**387**	**750**	**1,254**	**(1,190)**	**388**	**(139)**	**419**	**769**	

P-MM

Summary Portfolio Capacity by Resource Type and Year, Installed MW	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-	9,113
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-	7,910
Renewable - Battery (Long Duration)	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	987	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149
Front Office Transactions - Winter	1,640	1,781	1,035	553	553	524	166	195	231	52	41	52	52	52	52	52	52	62	46	85	364
Front Office Transactions - Summer	1,683	1,874	1,637	1,525	1,535	586	547	535	587	158	83	53	66	65	48	120	132	182	231	252	595
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-	(1,141)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(1,770)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(247)	(237)	-	-	-	-	(593)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,729**	**5,086**	**8,443**	**7,803**	**3,646**	**5,264**	**3,897**	**1,965**	**1,505**	**4,159**	**809**	**234**	**287**	**739**	**1,306**	**(1,095)**	**373**	**(166)**	**416**	**763**	

W-11 CETA Max Benefit

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
	Installed Capacity, MW																				
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429	4,977
DSM - Demand Response	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-	930
Renewable - Wind	-	194	1,717	-	100	457	500	-	-	4,788	3,607	-	-	-	-	-	-	-	-	-	11,363
Renewable - Utility Solar	-	-	1,469	1,600	483	2,589	1,298	120	108	600	-	841	-	-	-	-	-	-	-	-	9,108
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	628	1,979	1,647	400	-	600	-	-	-	-	1,207	-	-	-	-	-	9,015
Renewable - Battery (Long Duration)	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-	1,184
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,572	1,745	1,342	776	704	441	305	384	520	200	46	31	31	31	31	38	38	59	24	39	418
Front Office Transactions - Summer	1,656	1,869	1,608	1,691	1,717	607	541	546	583	184	26	3	3	3	3	3	3	3	3	3	553
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-	(1,840)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,070)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	-	(237)	-	-	(247)	(237)	-	-	(64)	-	(657)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,647**	**5,045**	**8,503**	**5,938**	**3,988**	**6,525**	**4,235**	**2,067**	**1,894**	**4,207**	**4,339**	**1,308**	**199**	**322**	**2,628**	**(498)**	**230**	**(352)**	**121**	**471**	

W-11 CETA No Climate

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-	1,240
DSM - Energy Efficiency	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429	4,977
DSM - Demand Response	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-	930
Renewable - Wind	-	194	1,717	-	-	457	500	-	-	6,486	3,607	-	-	-	-	-	-	-	-	-	12,961
Renewable - Utility Solar	-	-	1,469	1,600	-	2,589	1,298	120	108	600	-	841	-	-	-	-	-	-	-	-	8,625
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	954	1,600	-	1,979	1,647	-	-	600	-	-	-	-	1,207	-	-	-	-	-	7,987
Renewable - Battery (Long Duration)	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-	1,184
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	27	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-	1,500
Front Office - Selected Markets	1,000	997	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,639	1,813	1,518	942	1,071	624	508	554	672	185	15	16	16	16	-	7	7	15	53	51	486
Front Office Transactions - Summer	1,623	1,821	1,652	1,711	1,818	622	544	559	591	66	-	-	-	-	-	-	-	-	-	-	550
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-	(1,840)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-	(2,335)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,070)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	(119)	-	(237)	-	-	(247)	(237)	-	-	(64)	-	(657)
Retire - Non-Thermal	(21)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(21)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,683**	**5,062**	**8,723**	**6,124**	**3,245**	**6,723**	**4,441**	**1,850**	**2,054**	**5,772**	**4,282**	**1,290**	**181**	**304**	**2,594**	**(532)**	**196**	**(399)**	**147**	**480**	

P12-RET Coal 30 NG 40

Summary Portfolio Capacity by Resource Type and Year, Installed MW	Installed Capacity, MW																				
Resource	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	Total
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas - Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	606	-	-	-	-	-	345	1,790	-	-	-	-	-	2,741
DSM - Energy Efficiency	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426	4,953
DSM - Demand Response	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-	929
Renewable - Wind	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	676	-	-	-	-	-	9,249
Renewable - Utility Solar	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-	7,855
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery	-	-	754	2,929	628	1,900	1,149	-	-	-	150	-	-	-	1,323	-	-	-	-	-	8,833
Renewable - Battery (Long Duration)	-	-	600	-	-	-	-	-	-	-	150	-	(600)	-	200	-	-	-	-	-	350
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35
Nuclear	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	500
Front Office - Selected Markets	998	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150
Front Office Transactions - Winter	1,640	1,781	962	448	691	531	216	290	298	79	65	62	65	65	719	742	805	1,069	1,085	1,100	636
Front Office Transactions - Summer	1,683	1,874	1,405	1,515	1,501	566	547	529	570	273	182	181	191	191	577	597	599	652	664	664	748
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-	(811)
Coal Early Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SCR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - SNCR	-	-	-	-	(450)	-	-	-	-	(418)	(1,199)	-	-	-	-	-	-	-	-	-	(2,067)
Coal - Duel Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	713	-	370	598	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	(598)	-	-	0
Coal Plant ceases running as Coal	-	(713)	-	(357)	(598)	-	-	(699)	-	-	-	-	-	-	-	-	-	-	-	-	(2,368)
Gas Plant End-of-life Retirements	247	-	-	-	-	-	-	-	-	-	-	(356)	-	-	(2,781)	-	-	-	-	-	(2,890)
Retire - Non-Thermal	(23)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23)
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - QF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Other	-	(22)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(22)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**4,740**	**5,086**	**8,538**	**7,688**	**3,300**	**5,251**	**3,947**	**2,054**	**1,555**	**3,801**	**882**	**372**	**(175)**	**878**	**2,728**	**309**	**1,593**	**1,311**	**1,888**	**2,190**	

Table 9.1 – Non-Emitting Peaking (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	-	-	-	-	303	-	-	-	-	1,240	-	-	-	-	-
P-MN		-	-	-	-	-	-	-	-	-	-	-	303	578	345	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P-HH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	951	-	-	-	-	-
P-SC	-	-	-	-	-	-	-	-	-	606	-	-	-	-	634	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	895	-	303	303	-	-	345	289	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P07-D3-D2 32	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	606	-	-	-	-	-	-	289	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	606	-	-	-	-	-	345	1,790	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	606	-	-	-	-	-	345	289	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.2 - DSM Energy Efficiency (Installed Capacity MW)

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	123	220	259	197	216	219	240	258	637	103	160	170	161	281	586	163	170	165	139	412
P-MN	123	220	259	198	217	221	243	259	637	105	160	170	161	288	586	164	170	165	139	412
P-MM	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P-HH	123	220	259	210	229	234	255	266	675	116	161	185	162	289	594	165	187	176	172	671
P-SC	123	220	259	206	225	230	245	265	637	114	160	170	162	288	586	165	170	165	158	429
P01-JB3-4 GC	123	220	259	208	228	219	241	259	637	116	163	172	163	288	542	163	183	175	141	428
P02-JB3-4 EOL	123	220	259	208	228	219	240	258	637	115	161	171	161	288	542	163	184	176	141	428
P03-Hunter3-SCR	123	220	259	198	216	220	240	258	637	105	149	170	161	288	586	163	186	176	143	429
P04-Huntington RET28	123	220	259	208	228	219	240	258	637	109	161	171	161	288	542	163	184	176	141	428
P05-No NUC	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429
P06-No Forward Tech	123	220	259	208	228	219	240	260	638	106	161	171	161	288	542	163	184	176	141	429
P07-D3-D2 32	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P08-No D3-D2	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P09-No WY OTR	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P10-Offshore Wind	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P11-Max NG	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P12-RET Coal 30 NG 40	123	954	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P13-All EE	123	220	259	289	330	334	392	457	1,016	215	301	283	292	457	816	230	253	241	343	1,231
P14-All GW	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P15-No GWS	123	220	259	198	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P16-No B2H	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P17-Col3-4 RET25	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P18-Cluster East	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P19-Cluster West	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426
P20-JB3-4 CCUS	123	220	259	197	214	219	236	261	665	112	175	185	162	277	594	150	170	169	139	426

Table 9.3 – DSM Demand Response (Installed Capacity MW)

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	72	39	143	38	161	120	33	16	33	-	-	-	51	-	-	170	19	19	-	-
P-MN	72	39	152	99	126	94	27	13	35	-	-	-	-	-	1	228	19	19	-	-
P-MM	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P-HH	72	39	154	119	117	81	26	-	37	5	13	12	26	-	-	239	22	19	-	-
P-SC	72	39	154	107	123	75	27	-	46	-	-	-	3	-	-	246	19	19	-	-
P01-JB3-4 GC	72	220	193	6	83	61	41	10	8	-	-	-	117	-	-	121	21	20	-	-
P02-JB3-4 EOL	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-
P03-Hunter3-SCR	72	53	167	105	111	90	31	13	35	-	-	2	-	-	-	225	19	38	-	-
P04-Huntington RET28	72	220	199	12	77	64	43	9	11	-	-	2	108	-	-	125	20	39	-	-
P05-No NUC	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-
P06-No Forward Tech	72	220	199	12	75	68	43	9	47	-	-	2	76	-	-	123	20	39	-	-
P07-D3-D2 32	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P08-No D3-D2	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P09-No WY OTR	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P10-Offshore Wind	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P11-Max NG	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P12-RET Coal 30 NG 40	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P13-All EE	72	39	152	109	119	91	29	13	35	-	1	-	2	-	4	265	70	20	-	778
P14-All GW	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P15-No GWS	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P16-No B2H	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P17-Col3-4 RET25	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P18-Cluster East	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P19-Cluster West	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-
P20-JB3-4 CCUS	72	39	152	109	133	81	27	16	22	-	-	-	7	-	-	233	19	19	-	-

Table 9.4 – Renewable Wind (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	194	1,717	-	-	-	500	-	11	5,477	1,821	-	-	-	-	-	-	-	-	-
P-MN	-	194	1,717	-	-	-	500	-	-	6,025	3,565	-	450	-	-	-	-	-	-	-
P-MM	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P-HH	-	194	1,717	-	-	174	500	-	-	7,922	2,321	-	-	-	-	-	-	-	-	-
P-SC	-	194	1,717	-	-	457	500	-	-	6,486	3,607	-	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P02-JB3-4 EOL	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P03-Hunter3-SCR	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P04-Huntington RET28	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P05-No NUC	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P06-No Forward Tech	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P07-D3-D2 32	-	194	1,937	-	100	300	-	-	-	6,165	1,755	-	-	-	-	-	-	-	-	-
P08-No D3-D2	-	194	1,937	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-
P09-No WY OTR	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P10-Offshore Wind	-	194	1,937	-	100	300	1,900	-	-	2,683	1,459	-	-	-	540	-	-	-	-	-
P11-Max NG	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P12-RET Coal 30 NG 40	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	676	-	-	-	-	-
P13-All EE	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P14-All GW	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P15-No GWS	-	194	296	-	100	300	-	-	-	2,349	1,282	-	-	-	-	-	-	-	-	-
P16-No B2H	-	194	1,937	-	100	-	1,900	400	-	2,783	959	-	-	-	540	-	-	-	-	-
P17-Col3-4 RET25	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P18-Cluster East	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P19-Cluster West	-	194	1,937	-	100	300	1,900	-	-	2,783	1,359	-	-	-	540	-	-	-	-	-
P20-JB3-4 CCUS	-	194	1,937	-	100	300	1,900	-	-	2,733	1,359	-	-	-	540	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.5 – Renewable Solar (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	1,469	1,600	-	2,519	1,298	-	288	241	-	-	-	-	1,400	-	-	-	-	-
P-MN	-	-	1,469	1,600	-	2,470	1,298	-	254	941	-	-	-	-	600	-	-	-	-	-
P-MM	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P-HH	-	-	1,469	1,600	-	3,006	1,298	-	4	1,288	241	-	-	-	-	-	-	-	-	-
P-SC	-	-	1,469	1,600	-	2,589	1,298	-	108	600	-	841	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P02-JB3-4 EOL	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P03-Hunter3-SCR	-	-	1,469	2,524	483	1,832	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P04-Huntington RET28	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P05-No NUC	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P06-No Forward Tech	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	600	-	-	-	-	-
P07-D3-D2 32	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P08-No D3-D2	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P09-No WY OTR	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P10-Offshore Wind	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P11-Max NG	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P13-All EE	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P14-All GW	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P15-No GWS	-	-	1,469	2,224	483	2,307	600	-	200	972	-	300	-	-	-	-	-	-	-	-
P16-No B2H	-	-	1,469	2,524	483	1,507	600	-	-	972	600	300	-	-	-	-	-	-	-	-
P17-Col3-4 RET25	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P18-Cluster East	-	-	1,469	2,524	483	1,907	2,373	-	-	972	-	300	-	-	-	-	-	-	-	-
P19-Cluster West	-	-	1,469	2,524	483	2,406	200	-	-	972	-	300	-	-	-	-	-	-	-	-
P20-JB3-4 CCUS	-	-	1,469	2,524	483	1,907	200	-	-	972	-	300	-	-	-	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.6 – Battery Storage (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	954	1,600	160	2,008	1,647	-	-	-	400	-	-	-	2,560	-	-	-	-	-
P-MN	-	-	954	1,600	-	2,304	1,647	-	-	600	-	-	-	-	2,356	-	-	-	-	-
P-MM	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P-HH	-	-	954	1,600	-	2,599	1,647	-	-	600	-	-	-	-	1,541	-	-	-	-	-
P-SC	-	-	954	1,600	-	1,979	1,647	-	-	600	-	-	-	-	1,207	-	-	-	-	-
P01-JB3-4 GC	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P02-JB3-4 EOL	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P03-Hunter3-SCR	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P04-Huntington RET28	-	-	954	2,929	628	2,300	1,149	-	-	-	-	-	-	-	100	-	-	-	-	-
P05-No NUC	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-
P06-No Forward Tech	-	-	954	2,929	628	1,900	1,149	-	-	200	350	-	-	-	200	-	-	-	-	-
P07-D3-D2 32	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	(196)
P08-No D3-D2	-	-	954	2,929	628	1,900	1,149	-	-	800	150	-	-	-	200	-	-	-	-	-
P09-No WY OTR	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P10-Offshore Wind	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	500	-	-	-	-	-
P11-Max NG	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	754	2,929	824	1,900	1,149	-	-	-	150	-	-	-	1,323	-	-	-	-	(196)
P13-All EE	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P14-All GW	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P15-No GWS	-	-	954	2,629	628	2,500	1,349	-	-	800	150	-	-	-	200	-	-	-	-	-
P16-No B2H	-	-	954	2,929	1,352	1,900	1,149	-	-	-	750	-	-	-	200	-	-	-	-	-
P17-Col3-4 RET25	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P18-Cluster East	-	-	954	2,929	628	1,900	3,322	-	-	-	150	-	-	-	200	-	-	-	-	-
P19-Cluster West	-	-	954	2,929	628	2,399	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-
P20-JB3-4 CCUS	-	-	954	2,929	628	1,900	1,149	-	-	-	150	-	-	-	200	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.7 – Battery, Long Duration (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P-MN	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P-HH	-	-	-	-	-	600	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P-SC	-	-	-	-	-	400	-	-	-	-	-	-	-	-	784	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	-	-	300	450	-	-	-	200	-	-	-	-	-
P07-D3-D2 32	-	-	600	-	-	-	-	-	-	-	150	-	(600)	-	200	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	-	-	600	150	-	-	-	200	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	-	-	-	150	-	-	-	200	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.8 – Nuclear (Installed Capacity MW)[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	-	-	-	-	-	-
P-MM	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P-HH	-	-	-	-	-	-	-	500	-	1,000	-	-	-	-	500	-	-	-	-	-
P-SC	-	-	-	-	-	-	-	500	-	-	500	500	-	-	-	-	-	-	-	-
P01-JB3-4 GC	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P02-JB3-4 EOL	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P03-Hunter3-SCR	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P04-Huntington RET28	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P05-No NUC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P06-No Forward Tech	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P07-D3-D2 32	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P08-No D3-D2	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-
P09-No WY OTR	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P10-Offshore Wind	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P11-Max NG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P12-RET Coal 30 NG 40	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P14-All GW	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P15-No GWS	-	-	-	-	-	-	-	500	-	500	500	-	-	-	1,000	-	-	-	-	-
P16-No B2H	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P17-Col3-4 RET25	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P18-Cluster East	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P19-Cluster West	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-
P20-JB3-4 CCUS	-	-	-	-	-	-	-	500	-	500	500	-	-	-	-	-	-	-	-	-

1 – Positive values indicate installed capacity in the first full year of operations

Table 9.9 – Coal End-of-life Retirements[1]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-MM	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-HH	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P-SC	-	-	-	(82)	-	(253)	(328)	(148)	-	(699)	-	-	-	-	-	-	-	(330)	-	-
P01-JB3-4 GC	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	(699)	-	(330)	-	-
P02-JB3-4 EOL	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P03-Hunter3-SCR	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P04-Huntington RET28	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P05-No NUC	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P06-No Forward Tech	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P07-D3-D2 32	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P08-No D3-D2	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P09-No WY OTR	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P10-Offshore Wind	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P11-Max NG	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P12-RET Coal 30 NG 40	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P14-All GW	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P15-No GWS	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	(330)	-	-	-	-	-
P16-No B2H	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P17-Col3-4 RET25	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P18-Cluster East	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P19-Cluster West	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-
P20-JB3-4 CCUS	-	-	-	(82)	-	(253)	(328)	(148)	-	-	-	-	-	-	-	-	-	(330)	-	-

1 – Negative values indicate retirement of coal fueled capacity

Table 9.10 – Coal with SNCR Installation[1,2]

Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	-	-	2,067	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	-	-	-
P-MN	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P-MM	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P-HH	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P-SC	-	-	-	2,335	-	-	-	-	-	(2,067)	-	-	-	-	-	-	-	(268)	-	-
P01-JB3-4 GC	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P02-JB3-4 EOL	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P03-Hunter3-SCR	-	-	-	1,864	-	-	-	-	-	(418)	(1,178)	-	-	-	-	-	-	(268)	-	-
P04-Huntington RET28	-	-	-	2,335	-	(459)	-	-	-	(418)	(1,190)	-	-	-	-	-	-	(268)	-	-
P05-No NUC	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P06-No Forward Tech	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P07-D3-D2 32	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P08-No D3-D2	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P09-No WY OTR	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P10-Offshore Wind	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P11-Max NG	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P12-RET Coal 30 NG 40	-	-	-	2,067	(450)	-	-	-	-	(418)	(1,199)	-	-	-	-	-	-	-	-	-
P13-All EE	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P14-All GW	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P15-No GWS	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	(268)	-	-	-	-	-
P16-No B2H	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P17-Col3-4 RET25	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P18-Cluster East	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P19-Cluster West	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-
P20-JB3-4 CCUS	-	-	-	2,335	-	-	-	-	-	(418)	(1,649)	-	-	-	-	-	-	(268)	-	-

1 – Positive values indicate first full year of operations with SNCR installed
2 – Negative values indicate retirement of coal fueled capacity with SNCR

Table 9.11 – Coal to Natural Gas Conversions[1,2]

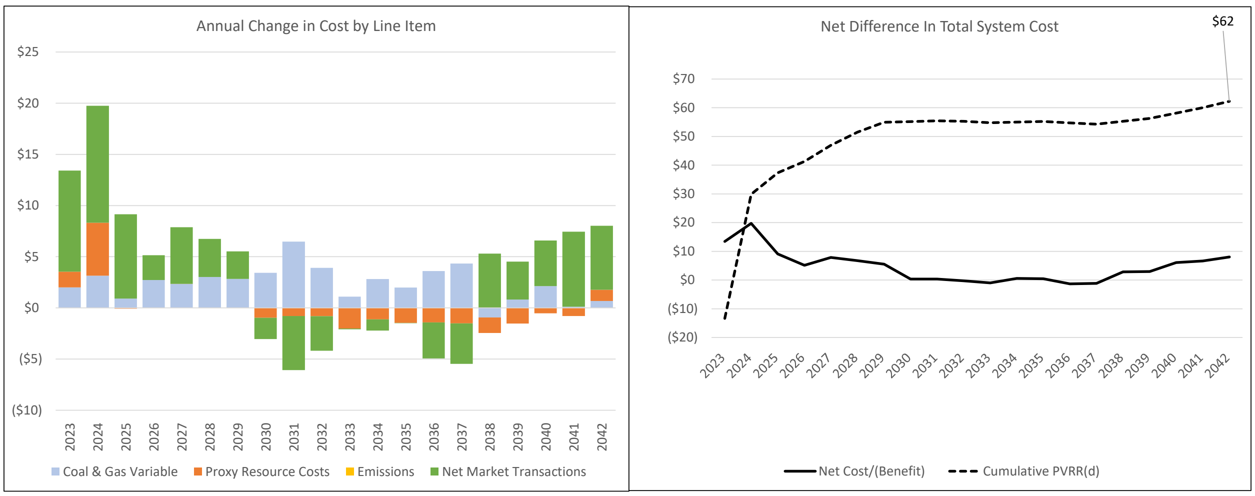
Study	Installed Capacity, MW																			
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
P-LN	-	713	-	370	598	-	-	699	-	(330)	-	-	-	-	(370)	(1,413)	-	(268)	-	-
P-MN	-	713	-	370	-	-	-	340	(354)	-	-	-	-	(160)	(210)	(699)	-	-	-	-
P-MM	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P-HH	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P-SC	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-
P01-JB3-4 GC	-	713	-	370	-	-	-	-	-	-	-	-	-	-	(370)	(713)	-	-	-	-
P02-JB3-4 EOL	-	713	-	1,069	-	-	-	-	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P03-Hunter3-SCR	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P04-Huntington RET28	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P05-No NUC	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P06-No Forward Tech	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P07-D3-D2 32	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P08-No D3-D2	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P09-No WY OTR	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P10-Offshore Wind	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P11-Max NG	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P12-RET Coal 30 NG 40	-	713	-	370	598	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	(598)	-	-
P13-All EE	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P14-All GW	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P15-No GWS	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(1,783)	-	-	-	-	-
P16-No B2H	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P17-Col3-4 RET25	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P18-Cluster East	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P19-Cluster West	-	713	-	370	-	-	-	699	-	-	-	-	-	-	(370)	(1,413)	-	-	-	-
P20-JB3-4 CCUS	-	713	-	370	-	-	-	349	-	-	-	-	-	-	(370)	(1,062)	-	-	-	-

1 – Positive values indicate first full year of natural gas-fueled operation
2 – Negative values indicate retirement of gas-converted capacity

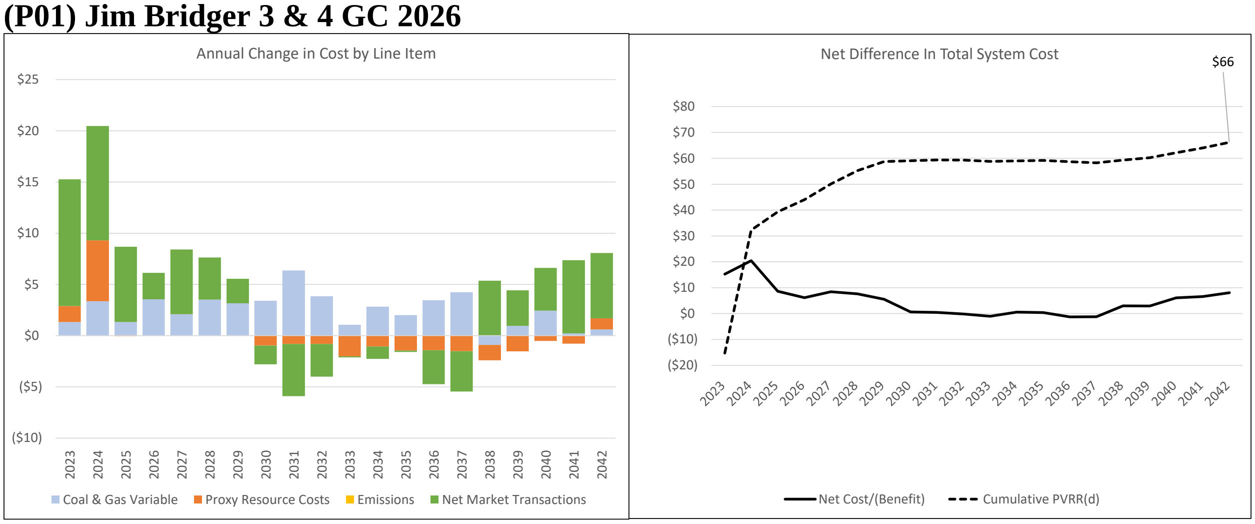
APPENDIX J – STOCHASTIC SIMULATION RESULTS

The following figures provide the cost summary detail comparing the MT model 95th percentile results to the mean results. This can indicate which cost categories pose the largest risks. Note that the 95th percentile sample is determined from the present value impact over the entire IRP study horizon, so it is not the illustrating the range of risk in each individual year.

2023 IRP Preferred Portfolio

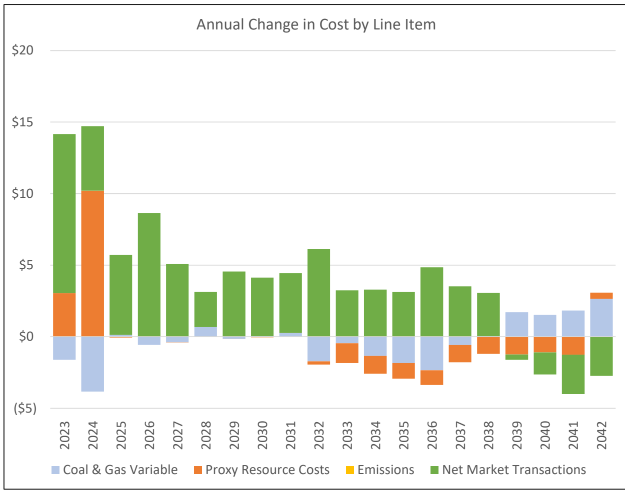


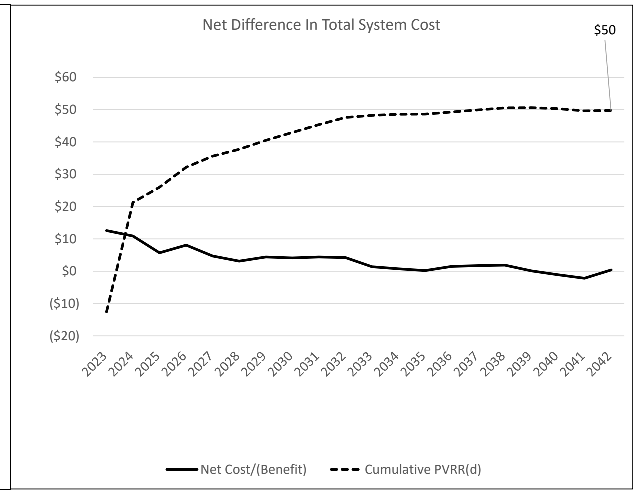
(P01) Jim Bridger 3 & 4 GC 2026



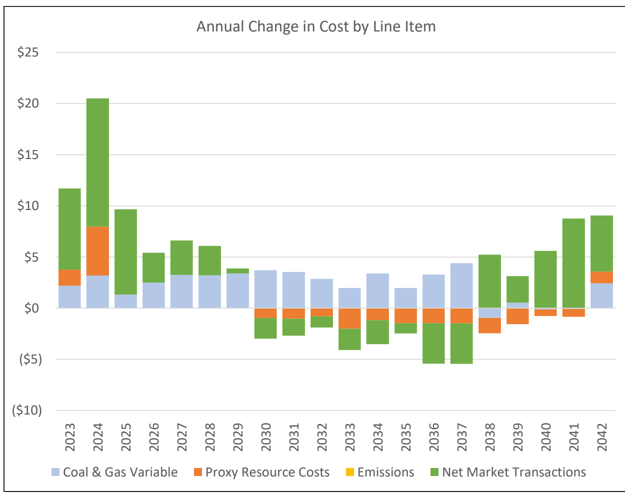
215

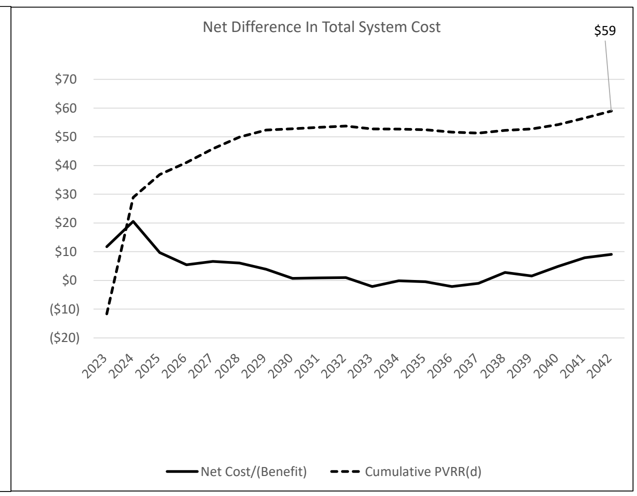
(P02) Jim Bridger 3 & 4 Coal EOL



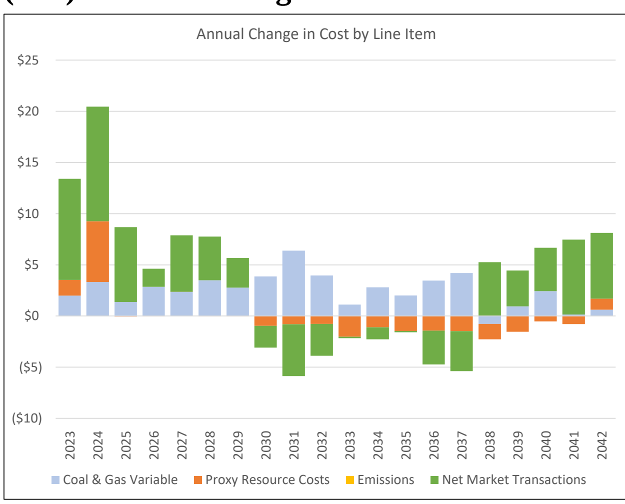


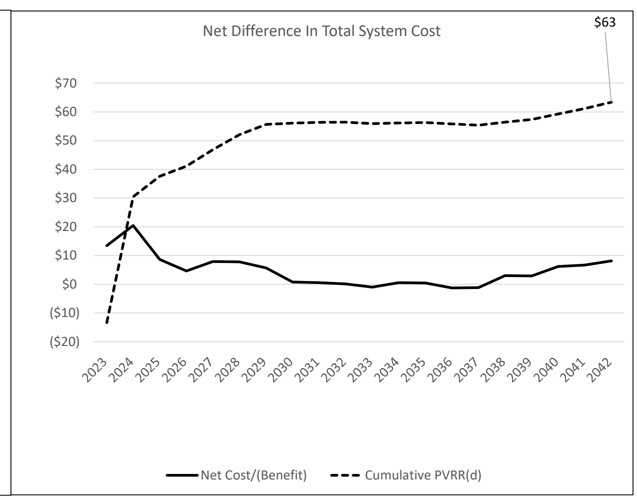
(P03) Hunter 3 SCR



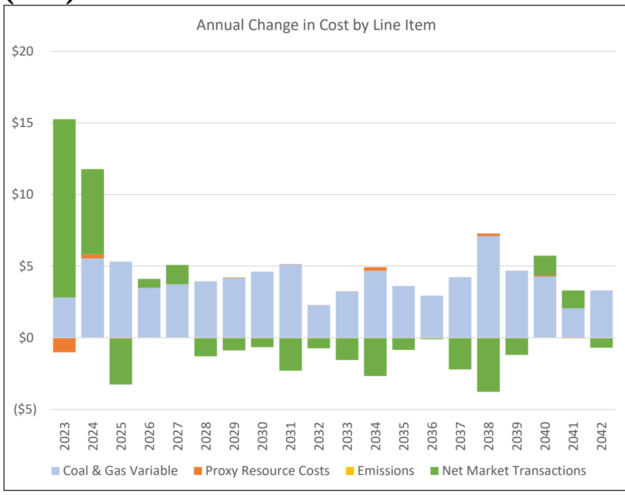


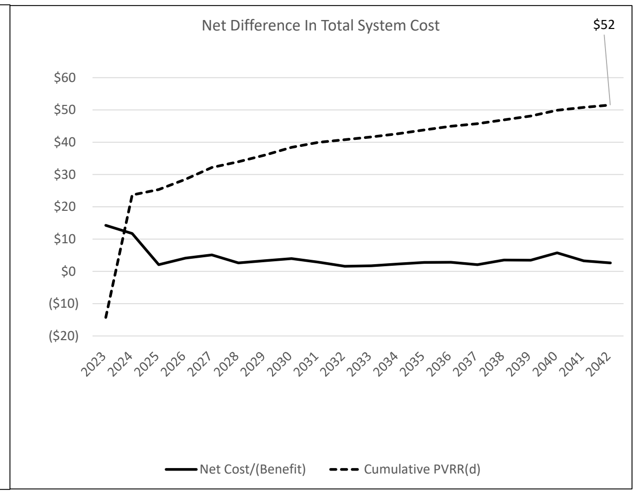
(P04) Retire Huntington 2028



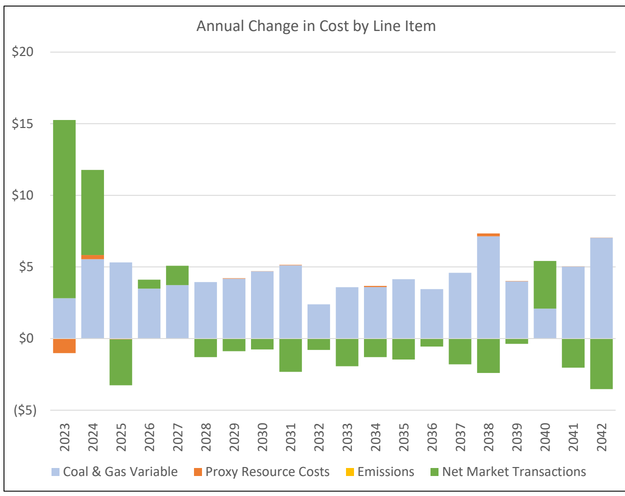


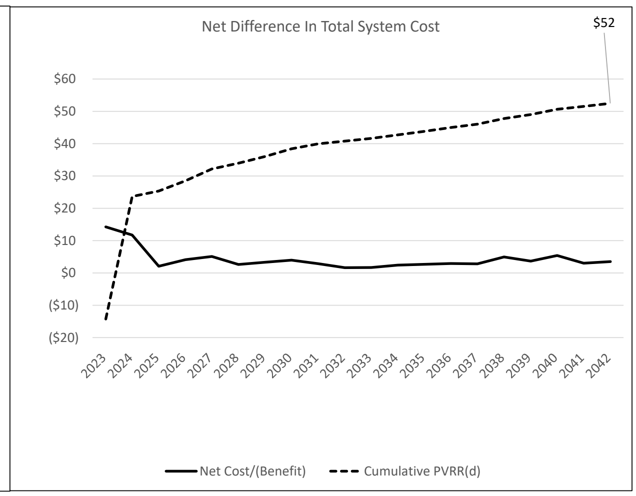
(P05) No NUC add Peaker



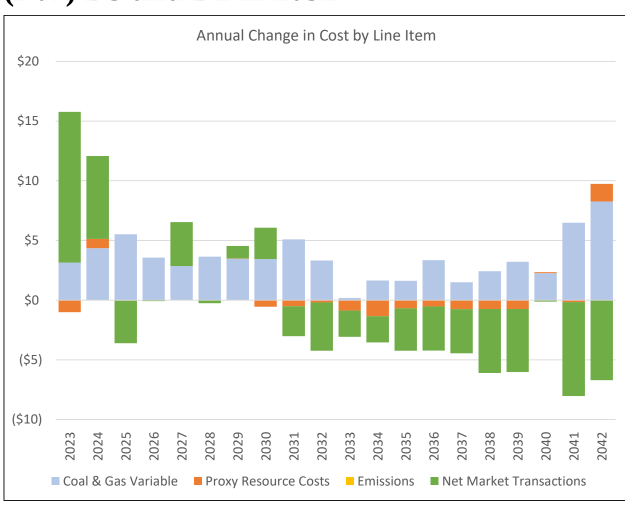


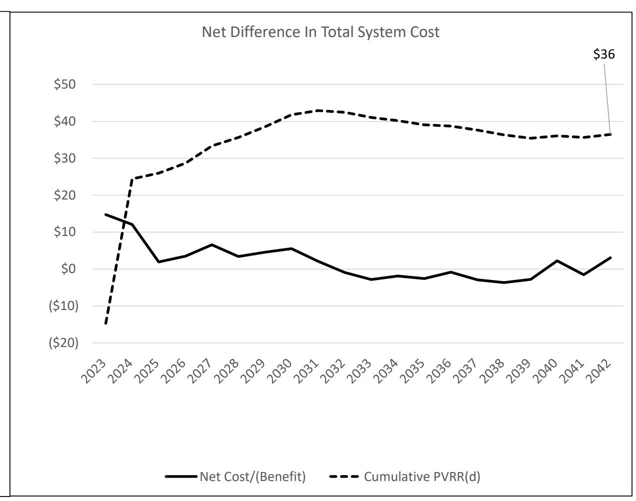
(P06) No NUC No Forward Tech



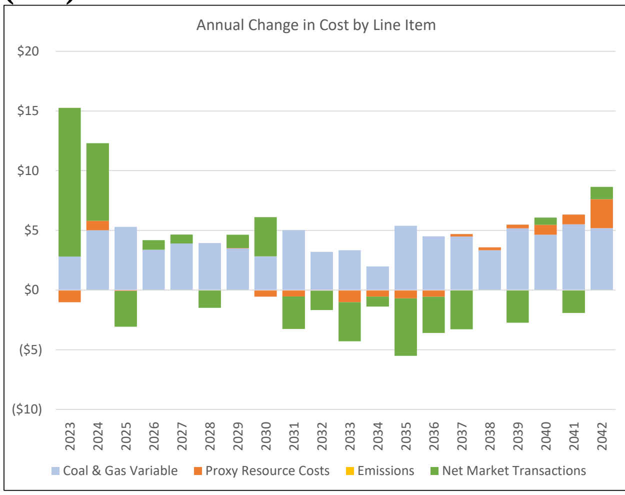


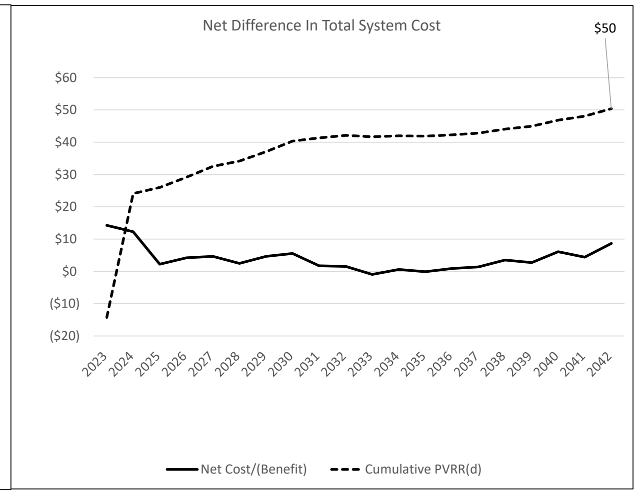
(P07) D3 and D2 in 2032



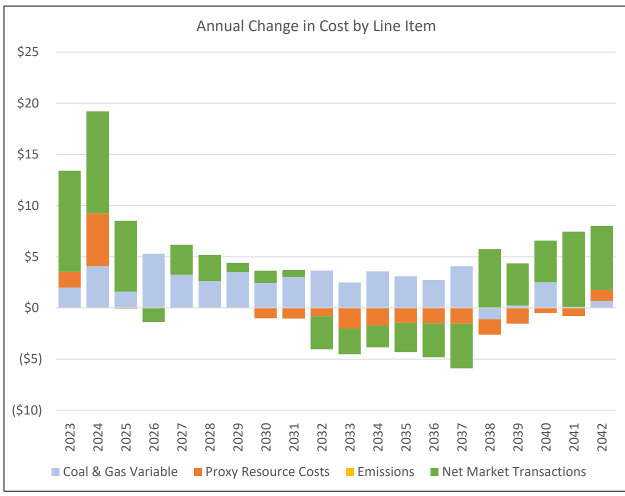


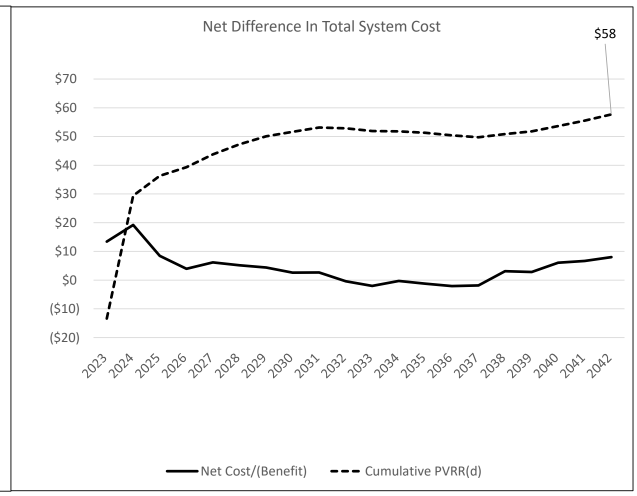
(P08) No D3 and D2



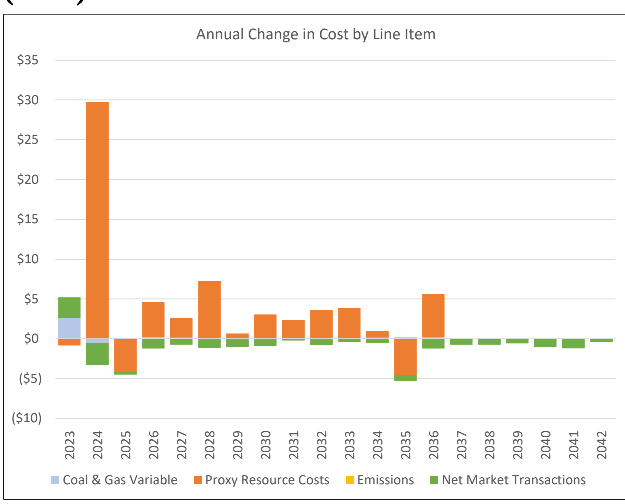


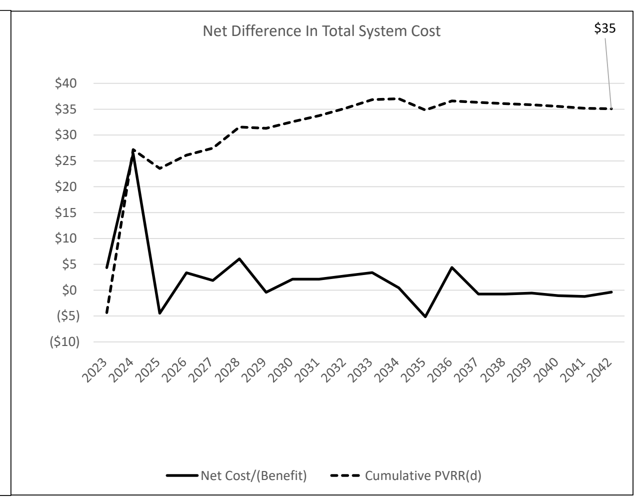
(P09) WY No OTR



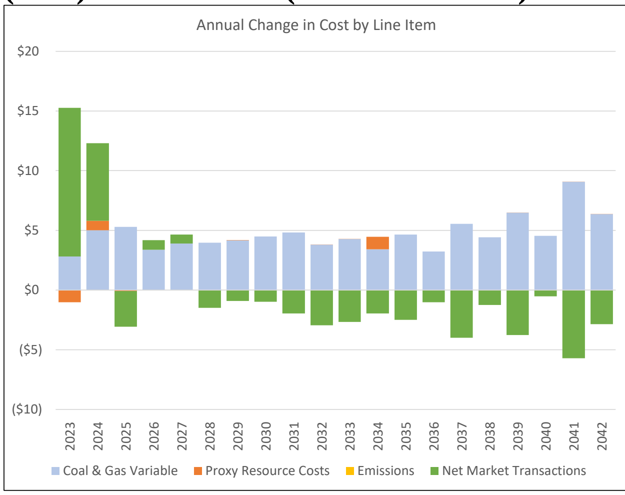


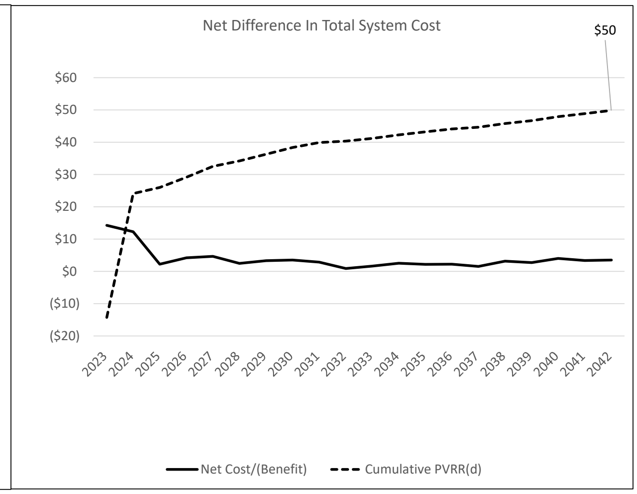
(P-10) Offshore Wind



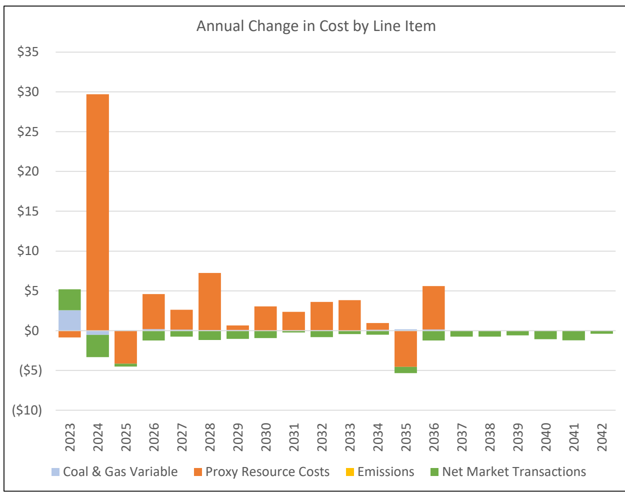


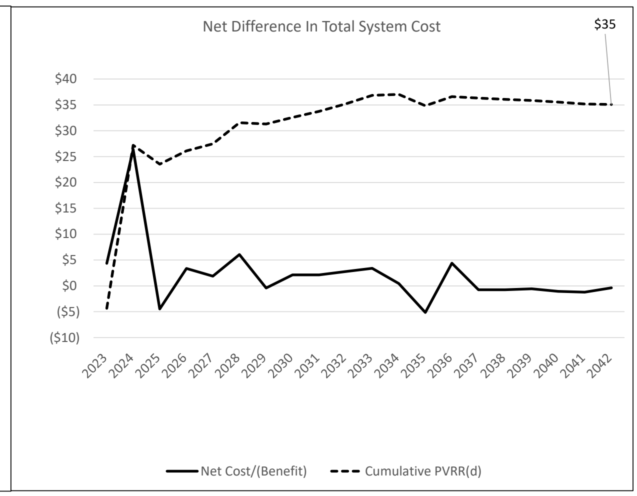
(P-11) Max Nat Gas (No NuC Peaker)



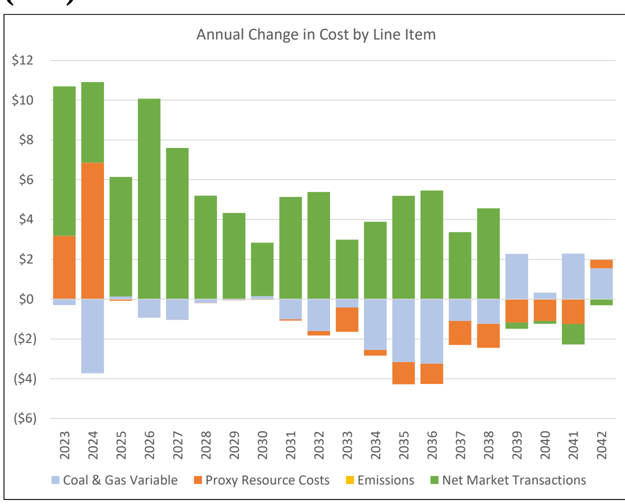


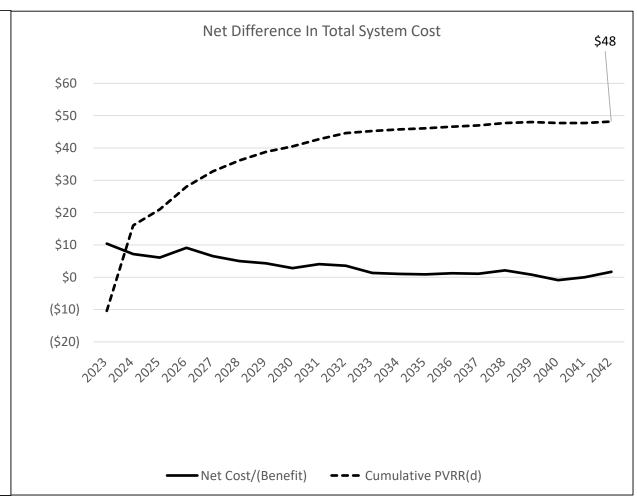
(P12) Coal Retire end 2029 Gas end of 2039



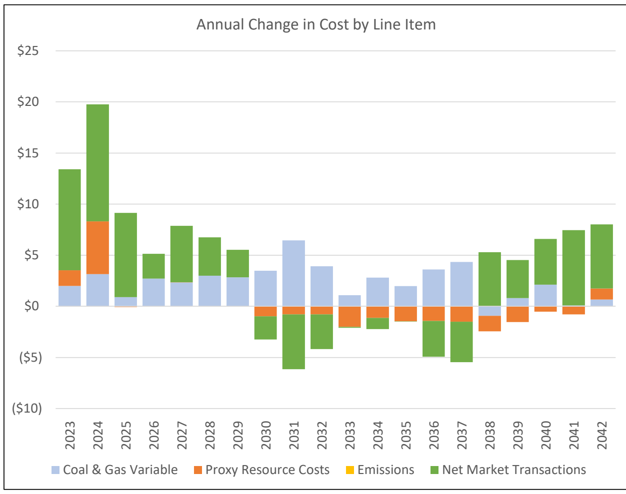


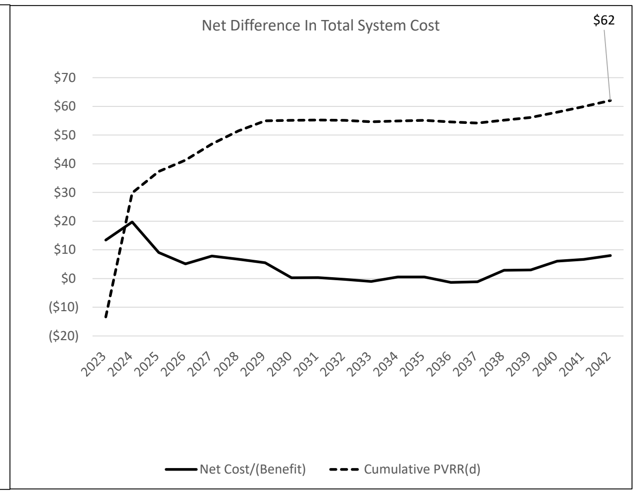
(P13) - ALL EE



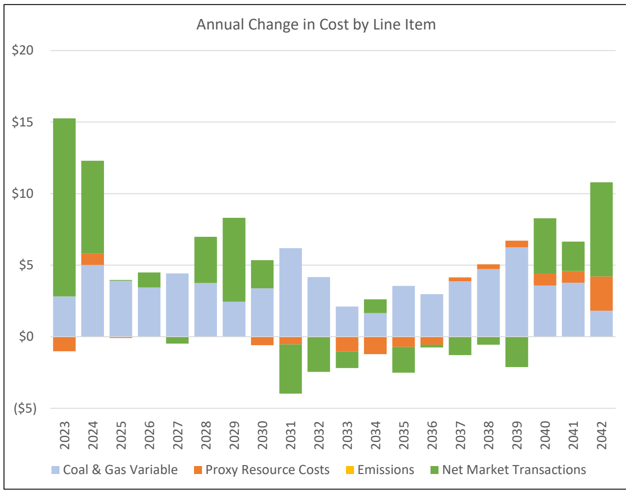


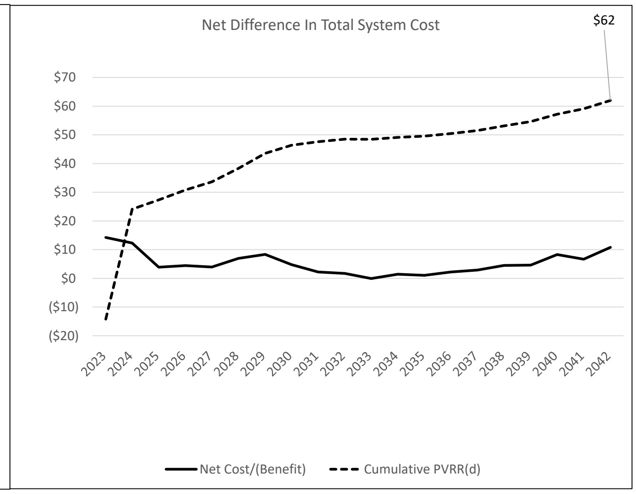
(P14) All Gateway



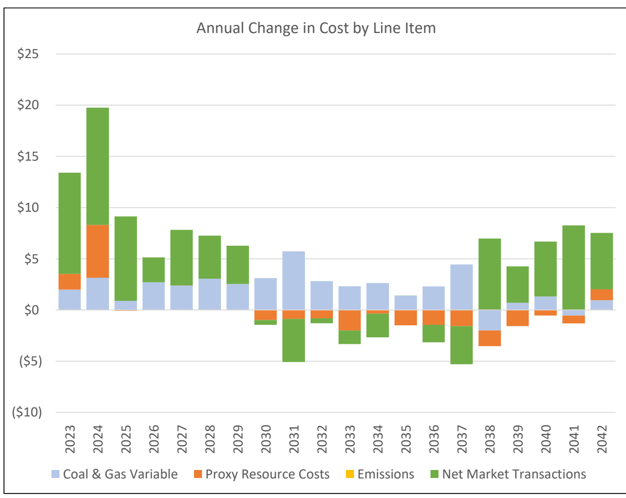


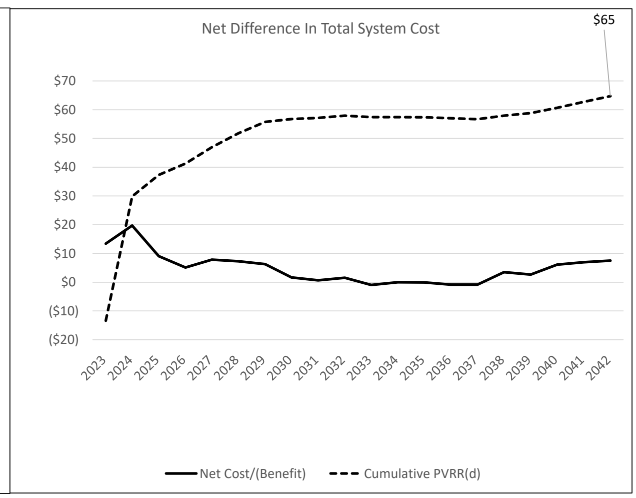
(P15) No GWS



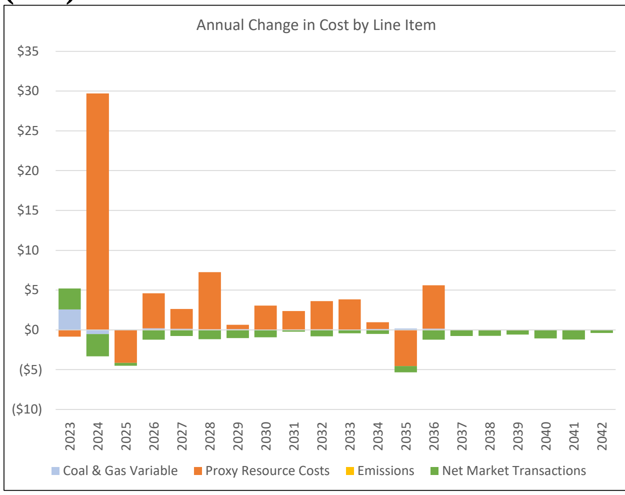


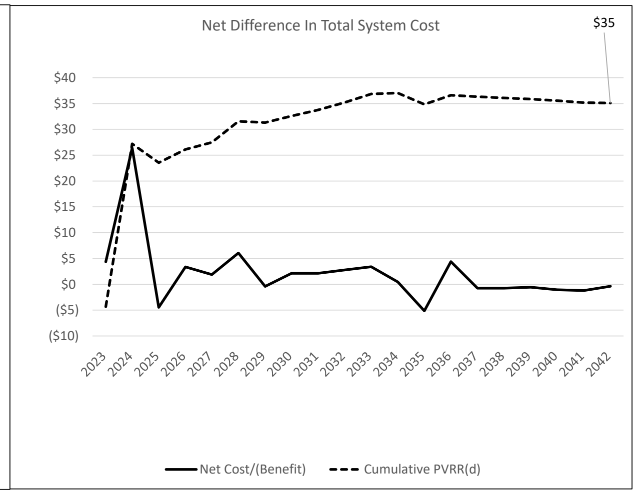
(P16) No B2H



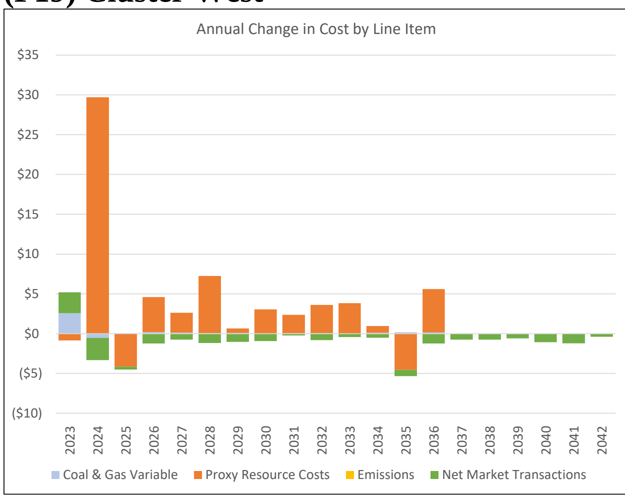


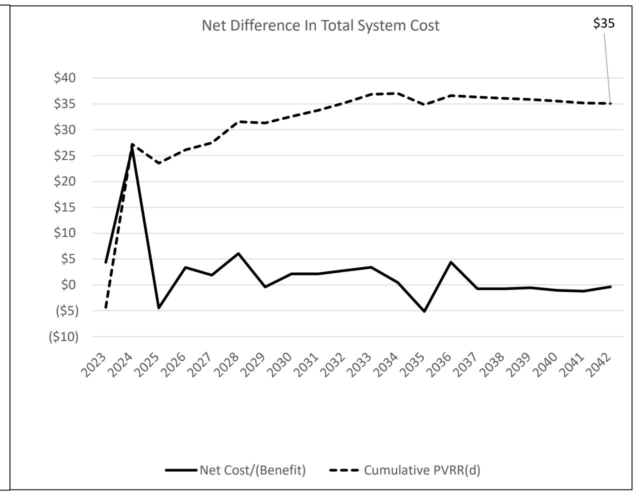
(P18) Cluster East





(P19) Cluster West





APPENDIX K – CAPACITY CONTRIBUTION

Introduction

The capacity contribution of a resource is represented as a percentage of that resource's nameplate or maximum capacity and is a measure of the ability of a resource to reliably meet demand. This capacity contribution affects PacifiCorp's resource planning activities, which are intended to ensure there is sufficient capacity on its system to meet its load obligations inclusive of a planning reserve margin. Because of the increasing penetration of variable energy resources (such as wind and solar) and energy-limited resources (such as storage and demand response), planning for coincident peak loads is no longer sufficient to determine the necessary amount and timing of new resources. To ensure resource adequacy is maintained over time, all resource portfolios evaluated in the integrated resource plan (IRP) have sufficient capacity to meet PacifiCorp's load obligations and a planning reserve margin in all hours of each year. Because all resources provide both energy and capacity benefits, identifying the resource that can provide additional capacity at the lowest incremental cost to customers is not straightforward. A resource's energy value is dependent on its generation profile and location, as well as the composition of resources and transmission in the overall portfolio. Similarly, a resource's capacity value (or contribution to ensuring reliable system operation) is also dependent on both its characteristics and the composition of the overall portfolio. To further complicate the analysis, PacifiCorp's portfolio composition changes dramatically over time, as a result of retirements and [Grab your reader's attention with a great quote from the document or use this space to emphasize a key point. To place this text box anywhere on the page, just drag it.]
expiring contracts.

In the 2019 IRP, PacifiCorp developed initial capacity contribution estimates for wind and solar capacity that accounted for expected declining contributions as the level of penetration increased. A key assumption in this analysis was that only a single variable was modified, for example, when evaluating solar penetration level, the capacity from wind and energy storage resources in the portfolio were held constant. As the preparation of the 2019 IRP continued, PacifiCorp identified that these initial estimates did not adequately account for the interactions between solar, wind, and energy storage and thus did not ensure that each portfolio was adequately reliable. Therefore, as part of the 2019 IRP PacifiCorp assessed each portfolio to verify that it would support reliable operation in each hour of the year. PacifiCorp has continued to perform this portfolio-wide reliability assessment as part of the 2021 and 2023 IRPs.

PacifiCorp calculates the capacity contribution values for wind and solar resources using the capacity factor approximation method (CF Method) as outlined in a 2012 report produced by the National Renewable Energy Laboratory (NREL Report)[1]. The CF Method calculates a capacity contribution based on a resource's expected availability during periods when the risk of loss of load events is highest, based on the loss of load probability (LOLP) in each hour. This CF Method analysis is performed using a portfolio that is comparable to the preferred portfolio. For the reasons discussed above, this analysis provides a reasonable estimate of capacity contribution value so long as the changes relative to the preferred portfolio are small, since in effect, the CF

[1] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report) at: www.nrel.gov/docs/fy12osti/54704.pdf

Method calculates the marginal capacity contribution of a one megawatt resource addition. Changes to the locations and quantities of wind, solar, and energy storage are key drivers of the marginal capacity contribution results.

CF Methodology

The NREL Report summarizes several methods for estimating the capacity value of renewable resources that are broadly categorized into two classes: 1) reliability-based methods that are computationally intensive; and 2) approximation methods that use simplified calculations to approximate reliability-based results. The NREL Report references a study from Milligan and Parsons that evaluated capacity factor approximation methods, which use capacity factor data among varying sets of hours, relative to a more computationally intensive reliability-based metric. As discussed in the NREL Report, the CF Method was found to be the most dependable technique in deriving capacity contribution values that approximate those developed using a reliability-based metric.

As described in the NREL Report, the CF Method "considers the capacity factor of a generator over a subset of periods during which the system faces a high risk of an outage event." When using the CF Method, hourly LOLP is calculated and then weighting factors are obtained by dividing each hour's LOLP by the total LOLP over the period. These weighting factors are then applied to the contemporaneous hourly capacity factors to produce a capacity contribution value.

The weighting factors based on LOLP are defined as:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j}$$

where w_i is the weight in hour i, $LOLP_i$ is the LOLP in hour i, and T is the number of hours in the study period, which is 8,760 hours for the current study. These weights are then used to calculate the weighted average capacity factor as an approximation of the capacity contribution as:

$$CV = \sum_{i=1}^{T} w_i C_i,$$

where C_i is the capacity factor of the resource in hour i, and CV is the weighted capacity value of the resource.

For fixed profile resources, including wind, solar, and energy efficiency, the average LOLP values across all iterations are sufficient, as the output of these resources is the same in each iteration. To determine the capacity contribution of fixed profile resources using the CF Method, PacifiCorp implemented the following three steps:

1. A multi-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Plexos Short-Term (ST) model. The key stochastic variables assessed as part of this analysis are loads, thermal outages, and hydro conditions. The LOLP for each hour in the year is calculated by counting the number of iterations in which system load and/or reserve obligations could not be met with available resources and dividing by the total

number of iterations.[2] For example, if in hour 19 on December 22nd there are three iterations with shortfalls out of a total of 50 iterations, then the LOLP for that hour would be 6 percent.[3]

2. Weighting factors were determined based upon the LOLP in each hour divided by the sum of LOLP among all hours within the same summer or winter season. In the example noted above, the sum of LOLP among all winter hours is 58 percent.[4] The weighting factor for hour 19 on December 22nd would be 1.0417 percent.[5] This means that 1.0417 percent of all winter loss of load events occurred in hour 19 on December 22nd and that a resource delivering in only in that single hour would have a winter capacity contribution of 1.0417 percent.

3. The hourly weighting factors are then applied to the capacity factors of fixed profile resources in the corresponding hours to determine the weighted capacity contribution value in those hours. Extending the example noted, if a resource has a capacity factor of 41.0 percent in hour 19 on December 22nd, its weighted winter capacity contribution for that hour would be 0.4271 percent.[6]

For resources which are energy limited, such as energy storage or demand response programs, the LOLP values in each iteration must be examined independently, to ensure that the available storage or control hours are sufficient. Continuing the example of December 22nd described above, consider if hour 18 and hour 19 both have three hours with energy or reserve shortfalls out of 500 iterations. If all six shortfall hours are in different iterations, a 1-hour energy storage resource could cover all six hours. However, if the six shortfall hours are in the same three iterations in hour 18 and hour 19 (i.e. 2-hour duration events), then a 1-hour storage resource could only cover three of the six shortfall hours.

Additional considerations are also necessary for hybrid resources which share an interconnection and cannot generate their maximum potential output simultaneously.
The details of the wind and solar resource modeling in the study period are an important aspect of the results. The study includes specific wind and solar volumes by resource for each hour in the period and includes the effects of calm and cloudy days on resource output. Where data was available, the modeled generation profiles for proxy resources are derived from calendar year 2018 hourly generation profiles of existing resources, adjusted to align with the expected annual output of each proxy resource.

The use of correlated hourly shapes produces variability across each month and a reasonable correlation between resources of the same type that are located in close proximity. It also results

[2] While PacifiCorp participates in the Northwest Power Pool (NWPP) reserve sharing agreement, this only provides energy from other participants within the first hour of a contingency event, e.g. a forced outage of a generator or transmission line. Shortfalls in the 2023 IRP are much more likely to result from changes in load, renewable resource output, or energy storage limitations, which do not qualify as contingency events. In light of this, PacifiCorp's analysis includes the first hour of every shortfall event.
[3] 0.6 percent = 3 / 500.
[4] For each hour, the hourly LOLP is calculated as the number of iterations with ENS divided by the total of 500 iterations. There are 288 winter ENS iteration-hours out of total of 5,832 winter hours. As a result, the sum of LOLP for the winter is 288 / 500 = 58 percent. There are 579 summer ENS iteration-hours out of total of 2,928 summer hours. As a result, the sum of LOLP for the summer is 579 / 500 = 116 percent.
[5] 1.0417 percent = 0.6 percent / 58 percent, or simply 1.0417 percent = 3 / 288.
[6] 0.4271 percent = 1.0417 percent x 41.0 percent.

in days with higher generation and days with lower generation in each month. As one would expect, days with lower renewable generation are more likely to result in shortfall events. As a result, basing CF Method capacity contribution calculations on an average or 12-month by 24-hour forecast of renewable generation will tend to overstate capacity contribution, particularly if there is a significant quantity of similarly located resources of the same type already in the portfolio, or if an appreciable quantity of resource additions is being contemplated. Even if an hourly renewable generation forecast is used, capacity contributions can be overstated if the weather underlying the forecast is not consistent with that used for similarly located resources used to develop the CF Method results. Because similarly located resources of the same type would experience similar weather in actual operations, a mismatch in the underlying weather conditions used in renewable generation forecasting will create diversity in the generation supply than would not occur in actual operations.

Because they are both influenced by weather, a relationship between renewable output and load is expected. To assess this relationship, PacifiCorp gathered information on daily wind and solar output from 2016-2019 and compared it to the load data from that period, the same load data that was used to determine stochastic parameters.

Each of the days in the historical period was assigned to a tier based on the rank of its daily average load within that month. This was done independently for the east and west sides of the system. The seven tiers were defined as follows:

Tier 1: The peak load day

Tier 2: 2nd – 5th highest load days

Tier 3: Days 6-10

Tier 4: Days 11-15

Tier 5: Days 16-20

Tier 6: Days 21-25

Tier 7: Days 26-31

The average wind and solar generation on the days in each tier was then compared to the average wind and solar generation for the entire month. The results indicated that west-side wind is often below average during the highest load days in a month, and above average during the lowest load days in a month. The results for other resource types were less pronounced, but do exhibit some patterns, as shown in Figure K.1 and Figure K.2.

Figure K.1 – Renewable Resources vs. High Load Conditions

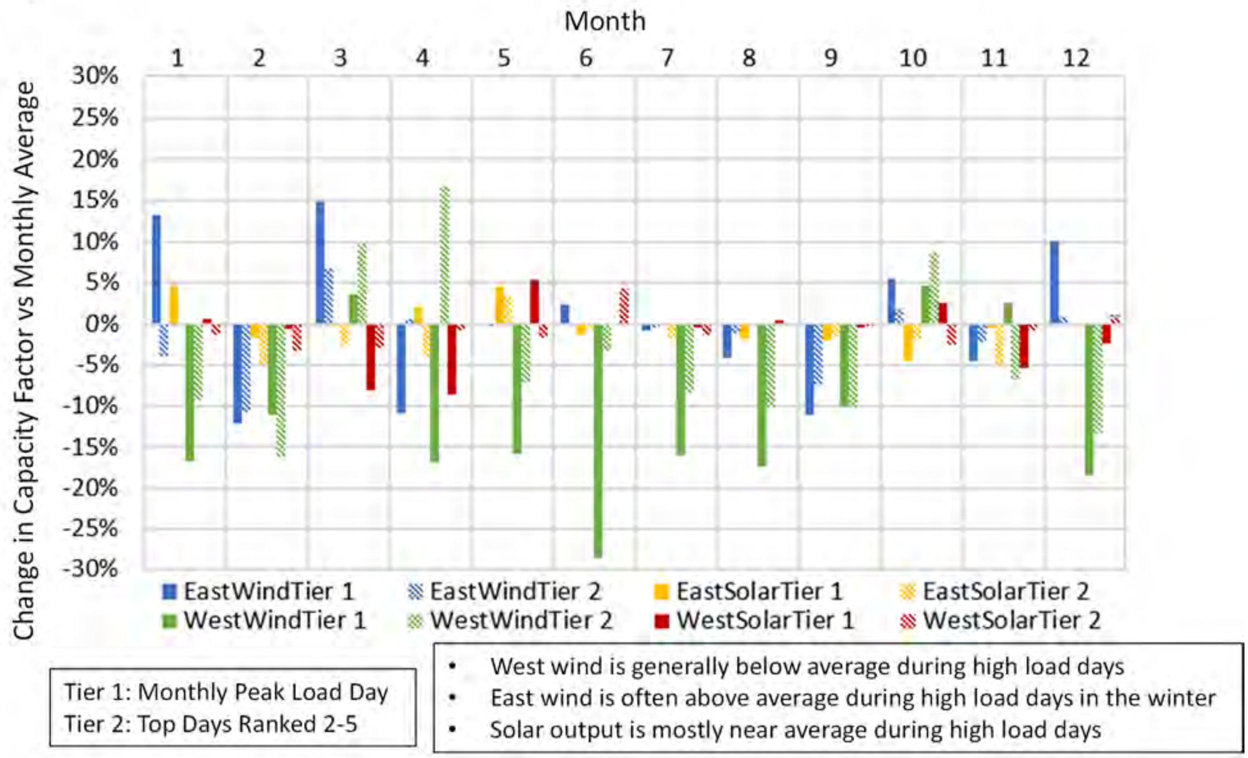
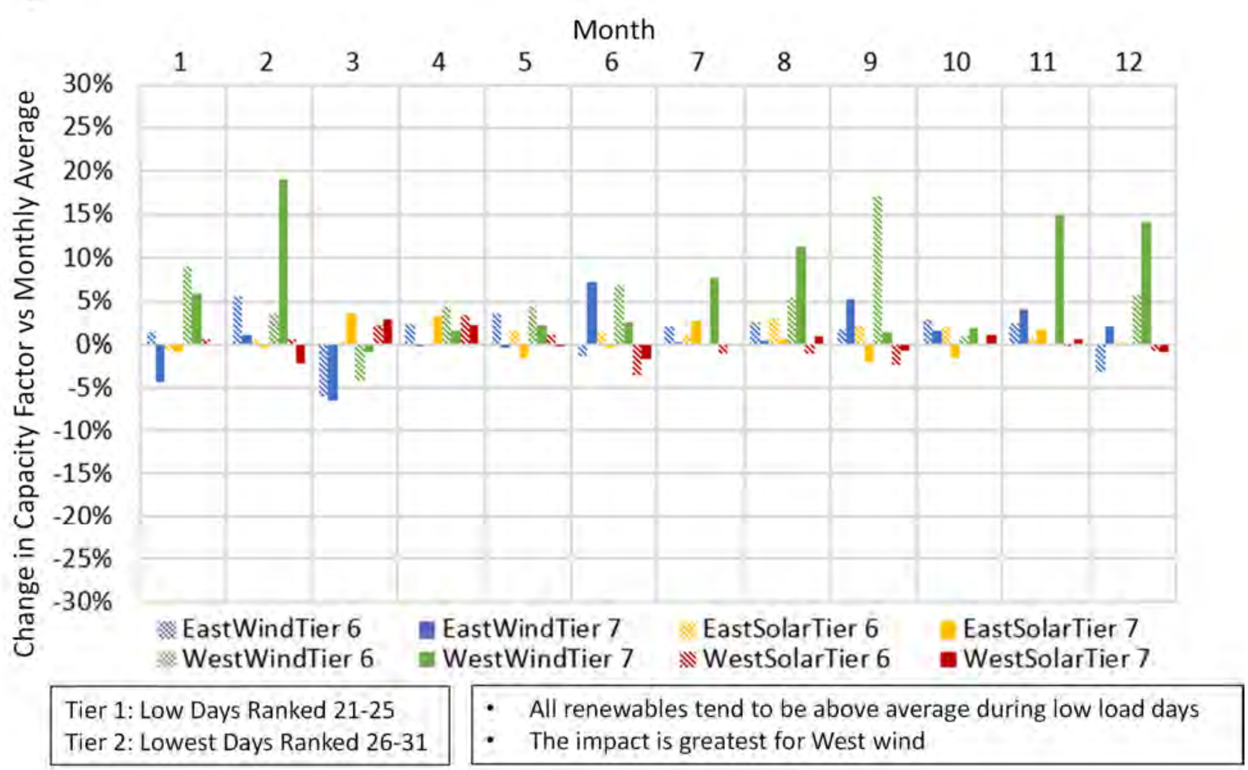


Figure K.2 – Renewable Resources vs. Low Load Conditions



Standard stochastic evaluation of prices, loads, etc. is based on standard deviations and mean reversion statistics. The results indicate that wind and solar output does exhibit relationships with load, but they are poorly represented by standard deviations – a different modeling technique is necessary.

Because of the complexity of the data, PacifiCorp did not attempt to develop wind and solar generation that varies by stochastic iteration for the 2023 IRP. Instead, PacifiCorp used a technique using the existing input framework: a single 8760 profile for each wind and solar resource that repeats every year. Because the load forecast rotates with the calendar, such that the peak load day moves to different calendar days, this creates differences in the alignment of load and renewable output across the IRP study horizon.

The order of the 2018 historical days was rearranged so that the forecasted intra-month variation in renewable output was reasonably aligned with the intra-month variation observed in the historical period for the days in the same load tier. Each day of renewable resource output derived from the 2018 history is mapped to a specific day for modeling purposes – only the order of the day's changes. To maintain correlations within wind and solar output, all wind and solar resources across the entire system are mapped using the same days.

While this technique builds on previous modeling and produces a reasonable forecast that captures some of the relationships between wind, solar, and load, additional work is needed in future IRPs to explore the variation and diversity of solar and wind output and further relationships with load.

APPENDIX L – PRIVATE GENERATION STUDY

Introduction

DNV prepared the Private Long-Term Resource Assessment for PacifiCorp. A key objective of this research is to assist PacifiCorp in developing private generation resource penetration forecasts to support its 2023 Integrated Resource Plan. The purpose of this study is to project the level of private generation resources PacifiCorp's customers might install over the next twenty years under low, base and high penetration scenarios.

PRIVATE GENERATION FORECAST

Behind-The-Meter Resource Assessment

PacifiCorp

Date: February 2, 2023

Table of Contents

List of Figures

List of Tables

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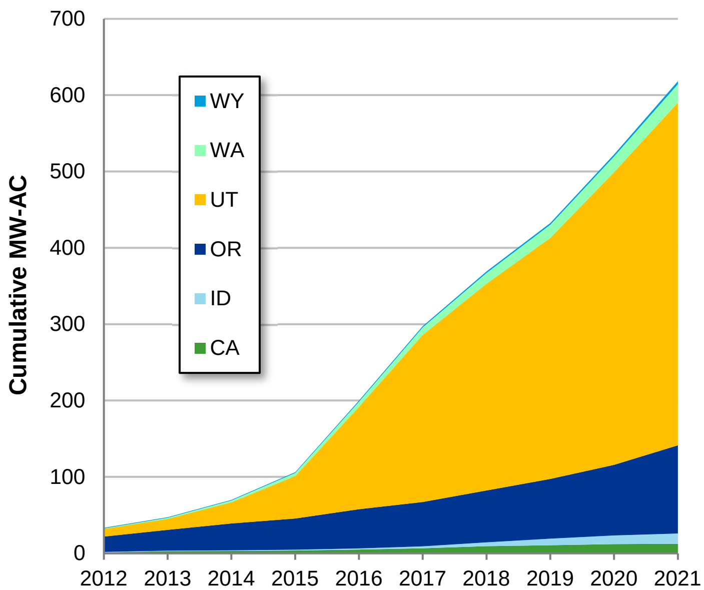
1 EXECUTIVE SUMMARY

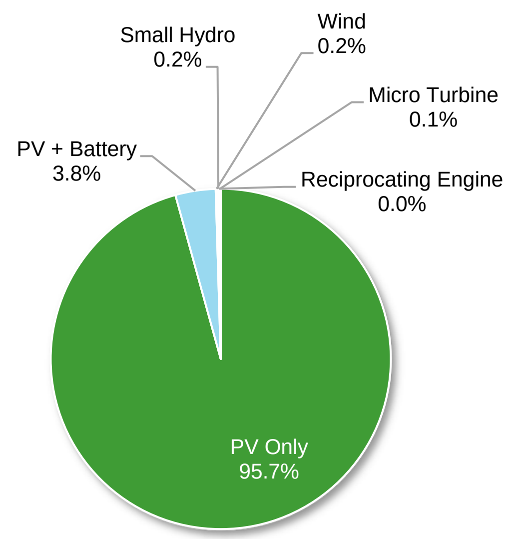
DNV prepared the Long-Term Private Generation (PG) Resource Assessment for PacifiCorp (the Company) covering their service territories in Utah, Oregon, Idaho, Wyoming, California, and Washington to support PacifiCorp's 2023 Integrated Resource Plan (IRP). This study evaluated the expected adoption of behind-the-meter (BTM) distributed energy resources (DERs) including photovoltaic solar (PV only), photovoltaic solar coupled with battery storage (PV + Battery), small wind, small hydro, reciprocating engines and microturbines over a 20-year forecast horizon (2023-2042) for all customer sectors (residential, commercial, industrial, and agricultural). The adoption model DNV developed for this study is calibrated to the current[1] installed and interconnected capacity of these technologies, shown in Figure 1-1.

Figure 1-1 Historic Cumulative Installed Private Generation Capacity, PacifiCorp, 2012-2021

Historic Cumulative Installed PG Capacity by State



Historic Cumulative Installed PG Capacity by Technology



To date, the majority of PG installed capacity and annual growth in capacity has been in Utah, which represents the largest portion go PacifiCorp's customer population—about 50% of all PacifiCorp customers are in the Company's Utah service territory. Roughly 99 percent of existing private generation capacity installed in PacifiCorp's service territory is PV or PV + Battery. To inform the adoption forecast process, DNV conducted an in-depth review of the other technologies and did not find any literature to suggest that they would take on a larger share of the private generation market in the Company's service territory in the future years of this study.

For each technology and sector, DNV developed three adoption scenarios: a base case, a high case, and a low case. The base case is considered the most likely projection as it is based on current market trends and expected changes in technology costs and retail electricity rates; the high and low cases are used as sensitivities to test how changes in costs and retail rates impact customer adoption of these technologies.

[1] PacifiCorp private generation interconnection data as of February 2022.

All scenarios use technology cost and performance assumptions specific to each state in PacifiCorp's service territory in the base year (2022) of the study. The base case uses the 2022 federal income tax credit schedules[2] and state incentives, retail electricity rate escalation from the AEO[3] reference case, and a blended version of the NREL Annual Technology Baseline[4] moderate and conservative technology cost forecasts as inputs to the modelling process. In the high case, retail electricity rates increase more rapidly, and technology costs decline at a faster rate compared to the base case. For the low case, retail electricity rates increase at a slower rate than the base case and technology costs decrease at a slower rate.

1.1 Study Methodologies and Approaches

The forecasting methodologies and techniques applied by DNV in this analysis are commonly used in small-scale, behind-the-meter energy resource and energy efficiency forecasting. The methods used to develop the state and sector-level results are described in more detail below.

1.1.1 State-Level Forecast Approach

DNV developed a behind-the-meter net economic perspective that includes, as costs, the acquisition and installation costs for each technology less the impact of available incentives and, as benefits, the customer's economic benefits of ownership such as energy and demand savings and export credits. For this study we assumed that the current net metering or net billing policies and tariff structures in each state continued throughout the study horizon. This resulted in the model incorporating benefits associated with net metering in Oregon, Washington, and Wyoming and net billing in Utah and California. We assumed customers in Idaho would accrue benefits based on the net billing policy in Utah throughout the study.

This analysis incorporated the current rate structures and tariffs offered to customers in PacifiCorp's service territories. Time-of-use rates, tiered tariffs and retail tariffs that include high demand charges increased the value of PV + Battery configurations compared to PV-Only configurations while other factors such as load profiles and DER compensation mechanisms minimized the impact of such tariffs on the customer economics of PV + Battery systems. The DER compensation mechanism in Oregon, Washington, and Wyoming — traditional net metering — does not incentivize PV + Battery storage co-adoption. In net metering DER compensation schemes, customers receive export credits for excess PV generation at the same dollar-per-kWh rate that they would have otherwise paid to purchase electricity from the grid. Net billing—the mechanism modelled in California, Idaho, and Utah—does incentivize PV + Battery storage co-adoption, as customers can lower their electricity bills by charging their batteries with excess PV generation and dispatching their batteries to meet on-site load during times of day when retail energy prices are high. From the perspective of utility bill savings alone, PV + battery systems are often not the most cost-effective option for most customers. Customers who seek the reassurance and reliability of backup power show more of a willingness to pay for this product, especially if they reside in areas that are prone to outages and severe weather events.

DNV combined technical feasibility characteristics of the identified PG technologies and potential customers with an economic analysis to calculate cost-effectiveness metrics for each technology, within each state that PacifiCorp serves, over the analysis timeframe. DNV then used a bass diffusion model to estimate customer PG adoption based on technical and

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[2] H.R.5376 - Inflation Reduction Act of 2022 (https://www.congress.gov/bill/117th-congress/house-bill/5376/text). Since the passing of the Inflation Recovery Act of 2022, the federal Investment Tax Credit (ITC) has been extended past its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034.

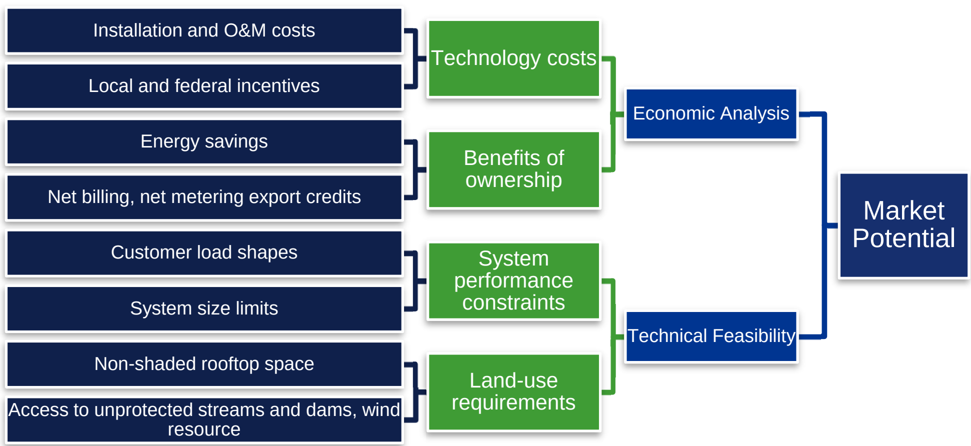
[3] U.S. Energy Information Administration, Annual Energy Outlook 2022 (AEO2022), (Washington, DC, March 2022).

[4] NREL (National Renewable Energy Laboratory). 2021. 2021 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

economic feasibility and incorporated existing adoption of each PG technology by state and customer segment as an input to the adoption model.

Technical feasibility characteristics were used to identify the potential customer base that could technically support the installation of a specific PG technology, or the maximum, feasible, adoption for each technology by sector. These factors included overall PG metrics such as average customer load shapes and system size limits by state, and specific technology factors such as estimated rooftop space and resource access based on location (for hydro and wind resource applicability). Simple payback was used in the customer adoption portion of the model as an input parameter to bass diffusion curves that determined future penetration of all PG technologies. The methodology and major inputs to the analysis are shown in Figure 1-2. Changes to technology costs and retail electricity rates used in the high and low cases impact the economic portion of the analysis.

Figure 1-2 Methodology to Determine Market Potential of Private Generation Adoption



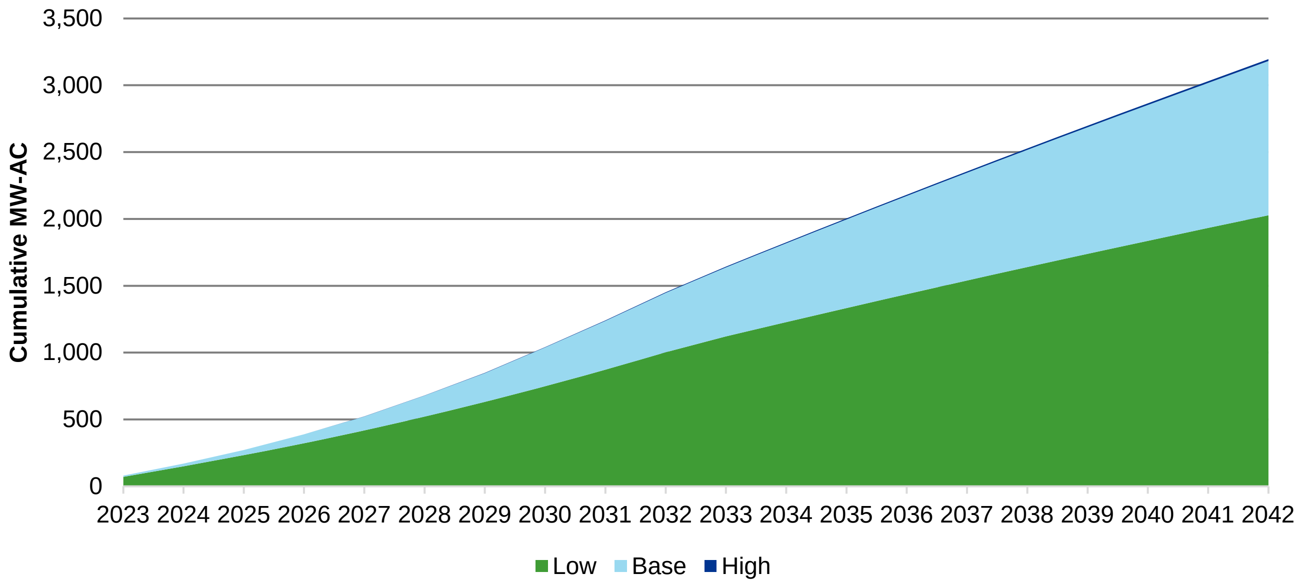
DNV developed Bass diffusion curves customized for each technology, state, and sector that also accounted for variation in willingness-to-adopt as cost effectiveness changes over time. The Bass diffusion curves were used to model annual and cumulative market adoption. Bass diffusion curves are widely used for forecasting technology adoption. Diffusion curves typically take the form of an S-curve with an initial period of slow early adoption that increases as the technology becomes more mainstream and eventually tapers off amongst late adopters. The upper limit of the curve is set to the maximum level of market adoption. In this analysis, the long-term maximum level of market adoption was based on payback. As payback was calculated by year in the economic analysis to capture the changing effects of market interventions over time, the maximum level of market adoption in the diffusion curves vary by year in the study.

The Bass diffusion curves used in the market potential analysis are characterized by three parameters—an innovation coefficient, an imitation coefficient, and the ultimate market potential. Together, these three parameters also determine the time to reach maximum adoption and overall shape of the curve. The innovation and imitation parameters were calibrated for each technology and sector, based on current market penetration and when PacifiCorp started to see the technology being adopted in each of its service territories. The calibrated curves show some segments still in the very early phases of adoption, while other markets are more mature.

1.2 Private Generation Forecast

In the base case scenario, DNV estimates 3,181 MW of new private generation capacity will be installed in PacifiCorp's service territory over the next twenty years (2023-2042). Figure 1-3 shows the base, low and high case scenarios. The low case scenario estimates 2,028 MW of new capacity over the 20-year forecast while the high case estimates 3,196 MW of new private generation capacity installed by 2042.

Figure 1-3 Cumulative New Capacity Installed by Scenario (MW-AC), 2023-2042



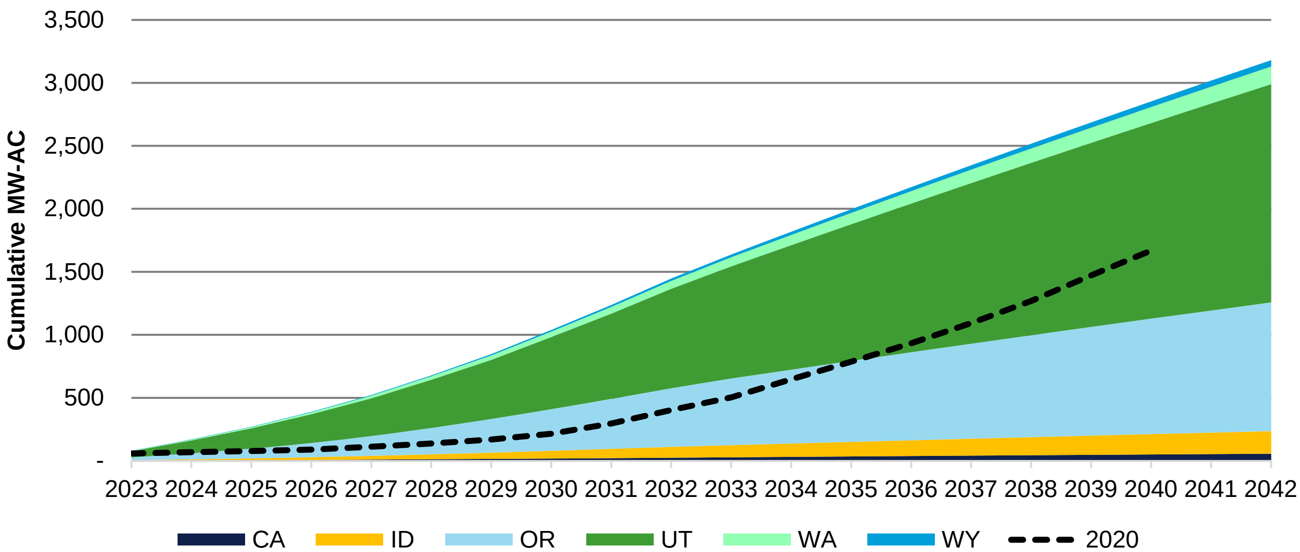
The sensitivity analysis showed a much greater margin of uncertainty on the low side than the high side. The Inflation Reduction Act of 2022 (IRA) extends tax credits for private generation that create very favorable economics for adoption, and those are embedded in the base case. We therefore limited our upper bound forecast to lower technology costs and higher retail electricity rates, and these produced only a small boost to adoption for technologies that were already cost effective under the IRA. In contrast, when we modelled our lower bound, we found that the increases to customer payback period were enough to tamp down adoption by a wider margin. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of private generation despite incentives being unchanged. The low case forecast is 36% less than the base case, while the high case cumulative installed capacity forecasted over the 20-year period is just 0.5% greater than the base case.

Figure 1-4 shows the base case forecast by state, compared to the previous (2020) study's total base case forecast.[5] This figure indicates that Utah and Oregon will drive most PG installations over the next two decades, which is to be expected given these two states represent the largest share of PacifiCorp's customers and sales. The base scenario estimates approximately 1,447 MW of new capacity will be installed over the next 10 years in PacifiCorp's territory—55% of which is in Utah, 32% in Oregon, and 6% in Idaho. Since the 2020 study, the federal Investment Tax Credit (ITC) has been extended for ten years at its original base rate levels and expanded to include energy storage. The tax credit increase and extension lowered the customer payback period for all technologies, making the customer economics of this study's base case more

[5] Cumulative capacity is adjusted to account for the difference in the forecast starting years (2021 in the previous study, versus 2023 in this study). Source: Navigant. 2020. "Private Generation Long-Term Resource Assessment (2021-2040)"

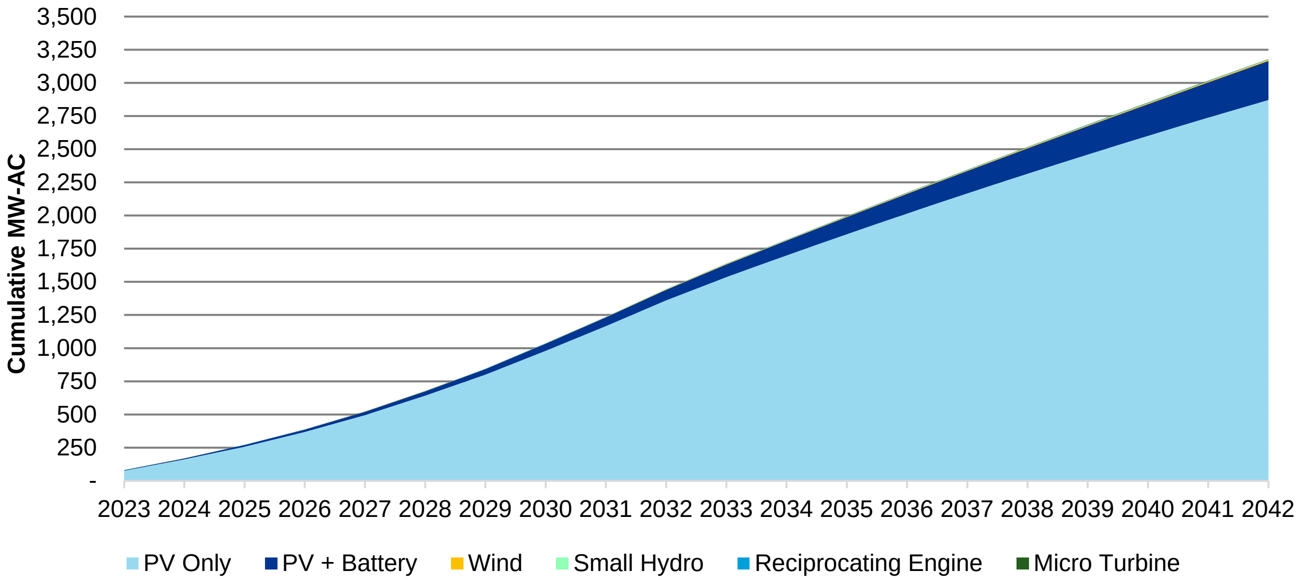
similar to the previous study's high case. In addition to the change in customer economics, projected PV capacity is expected to grow at a faster rate in the early years and at a slower rate towards the end of the forecast period. The key drivers of these differences include larger average PV system sizes, a steeper decline in PV + Battery costs at the start of the forecast period, and the maturity of rooftop PV technology.

Figure 1-4 Cumulative New Capacity Installed by State (MW-AC), 2023-2042, Base Case



In Figure 1-5 below, the base case forecast is presented by technology for all states in PacifiCorp's service territory. First year PV Only is estimated to grow by 76 MW and PV + Battery by 3 MW. These two technologies make up 99% of new installed private generation capacity forecasted. The results section of the report contains results by technology for the high, base, and low sectors. Additionally, total PV capacity forecasted is presented by sector in that section as well.

Figure 1-5 Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, Base Case



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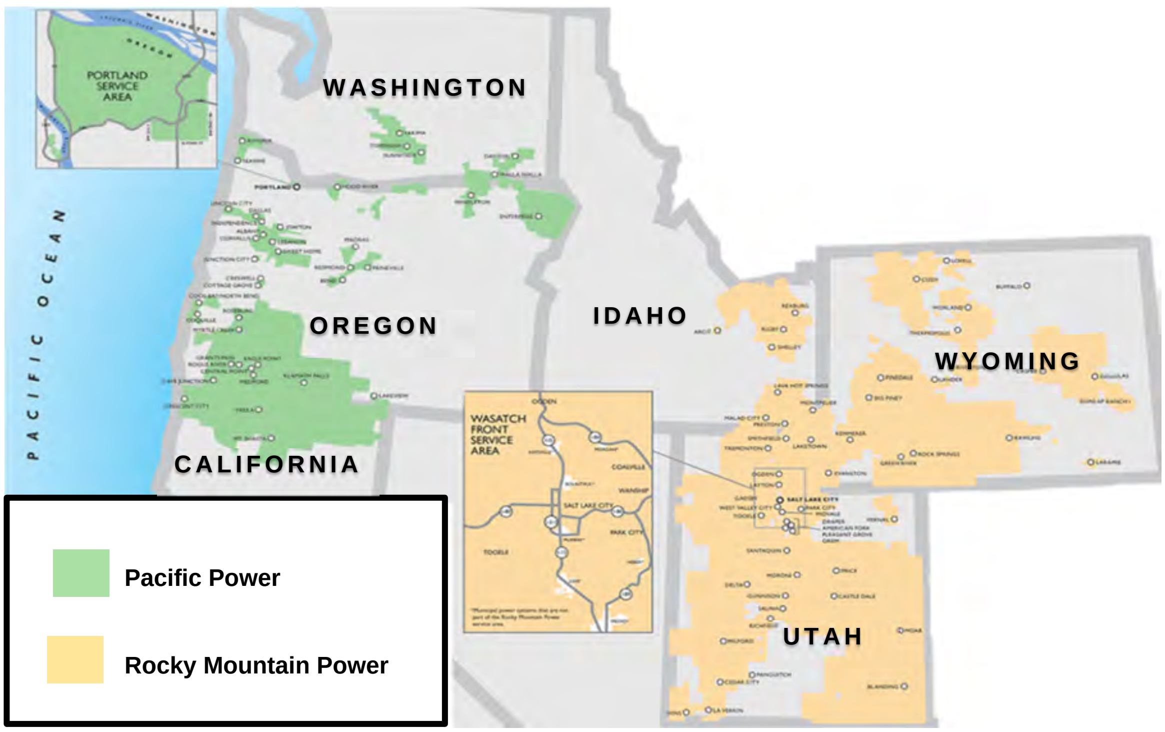
2 STUDY BACKGROUND

DNV prepared this Private Generation Long-term Resource Assessment on behalf of PacifiCorp and representing their service territory in six states—shown in Figure 2-1—California, Idaho, Oregon, Utah, Washington, and Wyoming. In this study, private generation technologies provide behind-the-meter energy generation at the customer site and are designed for the purpose of offsetting customer load and/or peak demand. The purpose of this study is to support PacifiCorp's 2023 Integrated Resource Plan by projecting the level of private generation resources PacifiCorp's customers may install over the next two decades under base, low, and high adoption scenarios. In addition to private generation, DNV also considered the cost-effective potential for high-efficiency cogeneration in Washington, consistent with the 480-109-060 (13) and 480-109-100 (6) of the Washington Administrative Code (WAC).

Figure 2-1 PacifiCorp Service Territory



Although there have been six previous studies involving private generation, DNV developed its assumptions, inputs, methodologies, and forecasts independently from these prior assessments that had been performed for PacifiCorp. The forecasting methodologies and techniques applied by DNV in this analysis are commonly used in small-scale, behind-the-meter energy resource and energy efficiency forecasting. This study evaluated the expected adoption of behind-the-meter technologies over the next 20 years, including:

1. Photovoltaic (Solar PV) Systems
2. Solar PV Paired with Battery Storage
3. Small Scale Wind
4. Small Scale Hydro
5. Reciprocating Engines

6. Microturbines

Project sizes were determined based on average customer load across the commercial, irrigation, industrial and residential customer classes for each state. The project sizes were then limited by each state's respective system size limits. Private generation adoption for each technology was estimated by sector in each state in PacifiCorp's service territory.

3 STUDY APPROACH AND METHODS

DNV used applicability/ technical feasibility, customer perspectives towards PGs, and project economics as the basis for forecasting expected market adoption of each private generation technology.

3.1 Technology Attributes

The technology attributes define the reference systems and their key attributes such as capacity factors, derate factors, and costs which are used in thepayback and adoption analyses. A full list of detailed technology attributes and assumptions by state and sector is provided in Appendix A. The following information provides a high-level summary of the key elements of the technologies assessed in this analysis.

3.1.1 Solar PV

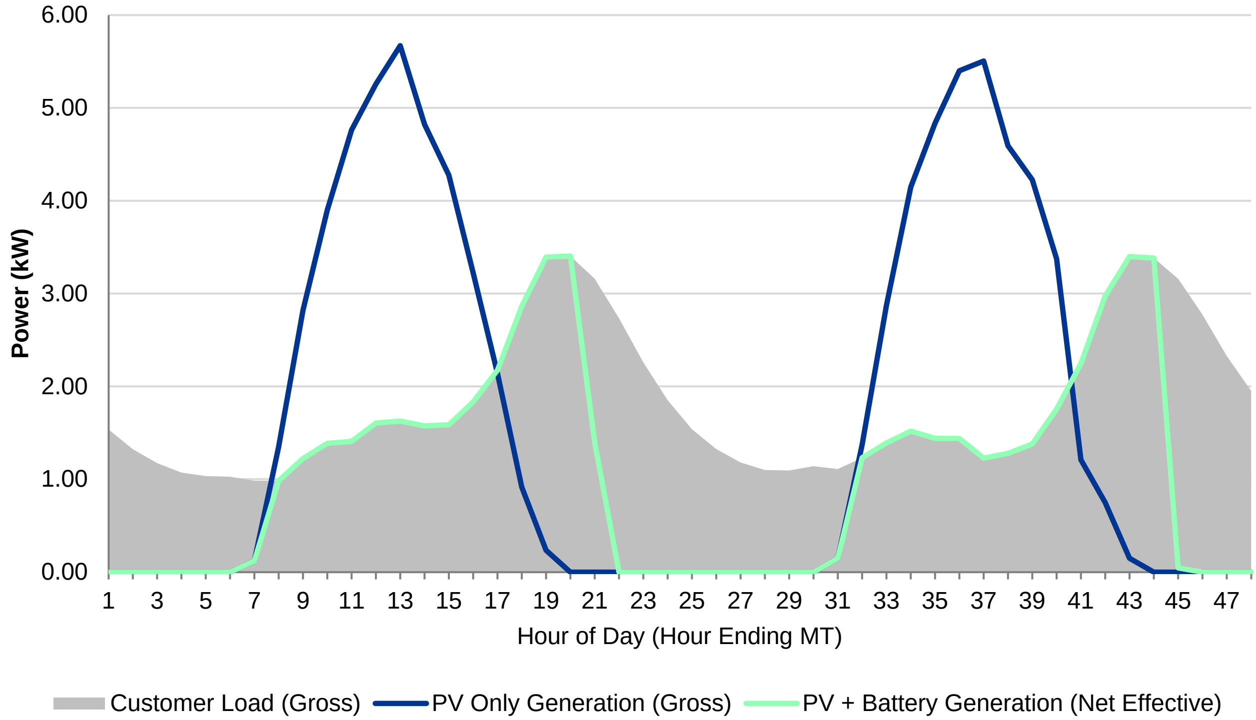
Solar photovoltaic (PV) systems convert sunlight into electrical energy. DNV modeled representative PV system energy output for residential and non-residential systems in each state to estimate first-year production. To model hourly production, DNV leveraged its SolarFarmer and Solar Resource Compass APIs. DNV's Solar Resource Compass API accesses and compares irradiance data from multiple data providers in each region. Solar Resource Compass also generates monthly soiling loss estimates for both dust soiling and snow soiling, as well as a monthly albedo profile. By incorporating industry standard models and DNV analytics, precipitation and snowfall data is automatically accessed and used to estimate the impact on energy generation.

Total PV capacity is forecasted by two different technology configurations: PV Only and PV + Battery.The PV technology in the PV + Battery systems were modeled using the same specifications as the PV Only technology, with the exception of nameplate capacity. DNV determined that average system sizes for PV + Battery configurations are on average larger than PV Only systems.

DNV further segmented the PV + Battery technology by new PV + Battery systems installed together and a Battery Retrofit case—where a battery is added to an existing PV system. The PV Only forecast presented in the results section of this report is net of customers who later adopt an add-on battery system (Battery Retrofit), and therefore become a part of the PV + Battery forecast. DNV assumes that customers in the Battery Retrofit case do not represent new incremental PV MW-AC capacity, however the generation profile of the customer changes from PV Only to PV + Battery.

An example residential customer load profile for two summer days is presented in Figure 3-1 to illustrate the difference between the generation profiles of PV Only and PV + Battery systems in this analysis.

Figure 3-1 Example Residential Summer Load Shape Compared to PV Only and PV + Battery Generation Profiles



3.1.1.1 PV Only

Table 3-1 provides the representative system specifications used to model residential standalone PV adoption. DC/AC ratio assumptions are derived from DNV's experience in the residential PV industry.

Table 3-1 Residential PV Only Representative System Assumptions

System Performance	Units	CA	ID	OR	UT	WA	WY
Nameplate Capacity	kW-DC	6.5	6.0	6.8	5.5	10.0	5.5
Module Type	n/a	c-Si	c-Si	c-Si	c-Si	c-Si	c-Si
PV Inverter	n/a	Microinverter					
Installation Requirements	n/a	Fixed-tilt Roof Mounted					
Capacity Factor	kWh/(kW-DC x 8760 hrs/yr)	13%	15%	16%	15%	13%	16%
DC/AC Derate Factor	n/a	1.118	1.123	1.121	1.129	1.132	1.118

Table 3-2 provides the representative system specification used to model non-residential standalone PV adoption. DC/AC ratio assumptions are derived from Wood Mackenzie's H1 2022 US solar PV system pricing report. The nameplate capacity of the system is dependent on the average customer size for each non-residential sector and state.

Table 3-2 Non-Residential PV Only Representative System Assumptions

System Performance	Units	CA	ID	OR	UT	WA	WY
Nameplate Capacity	kW-DC	30-150	37-100	30-115	60-750	20-100	18-25
Module Type	n/a	c-Si	c-Si	c-Si	c-Si	c-Si	c-Si
PV Inverter	n/a	Three-phase string inverter					
Installation Requirements	n/a	Flat Roof Mounted					
Capacity Factor	kWh/(kW-DC x 8760 hrs/yr)	14%	13%	12%	14%	12%	12%
DC/AC Derate Factor	n/a	1.30	1.30	1.30	1.30	1.30	1.30

The full list of nameplate capacity assumptions by sector and state can be found in Appendix A. For all PV systems, DNV assumed a linear degradation rate of 0.5% across the expected useful life of the system.

3.1.1.2 PV + Battery

Technology attributes consist of a representative system, operational data, cost assumptions, and capital costs which are used in conjunction to develop a total installed cost in dollars per kW. DNV reviewed PacifiCorp's history of interconnected projects to develop its customer level assumptions for number of batteries, usable energy capacity, and rated power at the state level. The resulting representative composite system is used for operational parameters and costs to be used for long-term adoption and forecasting purposes.

DNV assumes a fully integrated battery energy storage system (BESS) product for the residential sector, which will include a battery pack and a bi-directional inverter based on leading residential battery energy storage manufacturers such as Tesla, Enphase, and Sonnen providing fully integrated BESS solutions. Table 3-3 presents the representative residential PV + Battery system assumptions used in this analysis. The system specifications for the commercial, industrial, and irrigation sector are listed in Appendix A.

Table 3-3 Residential PV + Battery Representative System Assumptions

Technology	System Performance	Units	CA	ID	OR	UT	WA	WY
PV	Nameplate Capacity	kW-DC	9.5	8.8	10.6	8.1	13.6	8.6
BESS	Total Usable Energy Capacity	kWh	12.5	12.5	14.0	12.5	14.0	10.0
	Total Power	kW	5.0	5.0	7.0	5.0	7.0	5.0
	Battery Duration	Hrs	2.5	2.5	2.0	2.5	2.0	2.0
	Roundtrip Efficiency	%	89%					
	Battery Pack Chemistry	n/a	Lithium-ion NMC (Nickel, Manganese, Cobalt)					

Residential and non-residential BESS can be installed as a standalone system, added to an existing PV system, or the system can be installed with a new PV system. DNV assumed all battery installations would be co-located with a PV system in an AC-coupled configuration, as standalone systems are ineligible for the federal ITC—explained further in section 3.2.5.

Battery adoption was forecasted separately for PV + Battery systems installed together, and the Battery Retrofit case—where a battery is added to an existing PV system. The basis of the Battery Retrofit forecast is the existing PV capacity in PacifiCorp's service territories and the PV Only capacity forecasted in this analysis. For the purpose of forecasting private generation capacity, the Battery Retrofit forecast is presented in the results section as a part of the PV + Battery capacity forecast. In the behind-the-meter battery storage capacity forecast, presented in Appendix E, the Battery Retrofit case is split out in the presentation of the results.

Battery degradation was modeled using DNV's Battery AI, a data-driven battery analytics tool that predicts short-term and long-term useable energy capacity degradation under different usage conditions. It combines laboratory cell testing data with artificial intelligence (AI) technologies to provide an estimation for battery energy capacity degradation over time. In this analysis, Battery AI models several current-generation, commercially available Nickel Manganese Cobalt (NMC) cells were used to predict expected degradation performance of "generic" cells. These cells were tested in the lab over periods of 6 – 12 months at multiple temperatures, C-rates, SOC ranges, and cycling/resting conditions. Predictions are generally constrained to within the bounds of the testing data. DNV has not explicitly modeled battery end-of-life (EOL), due to a lack of testing data in this region of operation. Earlier of 20-years or 60% capacity retention is generally considered to represent EOL.

Both cycling and calendar effects were considered in the degradation assessment. It is also assumed the battery cell temperature will be controlled to be around 25°C for majority of the time with proper thermal management (ventilation, HVAC). DNV notes that temperature plays a key role in battery degradation. Continuous operation under extreme low or high temperatures will accelerate degradation in battery state of health.

Cost Assumptions

Cost assumptions are used in conjunction with representative system parameters to develop system costs. The costs are developed for each state and sector, inclusive of hardware, labor, permitting and interconnection fees, as well as provisions for sales and marketing, overhead, and profit. For labor costs, we used state level data from the US Bureau of Labor Statistics (BLS) for electricians, laborers (construction), and electrical engineers.

Total installed costs (or capital expenditures) are based on cost assumptions that were developed on a bottom-up basis—including hardware, installation/interconnection, as well as a provision for sales, general, and administrative costs and overhead. Capital expenditures (Cap-Ex) are expenditures required to achieve commercial operation in a given year. Pricing is indicative of a cash sale, not a lease or PPA, and it does not account for ITC or local rebates. Examples of total installed costs by category for residential and commercial customers in Utah are shown in Figure 3-2 and Figure 3-3, respectively. The full set of cost and incentive assumptions used in the analysis can be found in Appendix A.

Figure 3-2 Cost of Residential PV Standalone, Battery Storage Retrofit to Existing PV, and PV + Battery Systems from DNV Bottom-up Cap-Ex Model, Utah

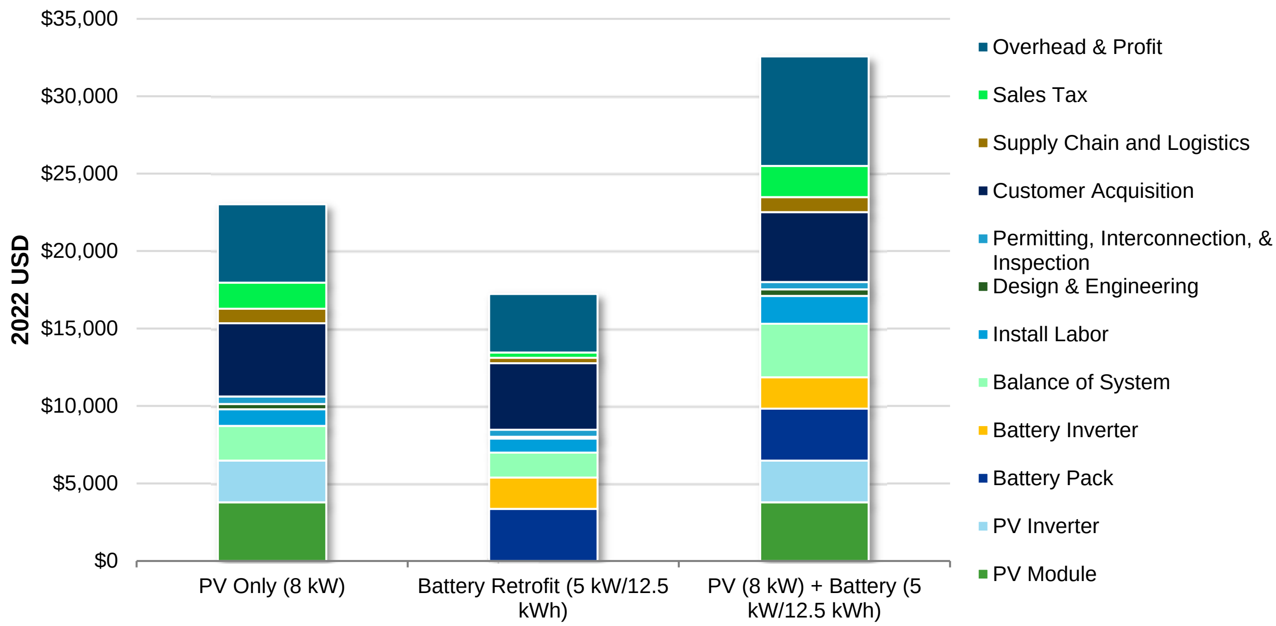
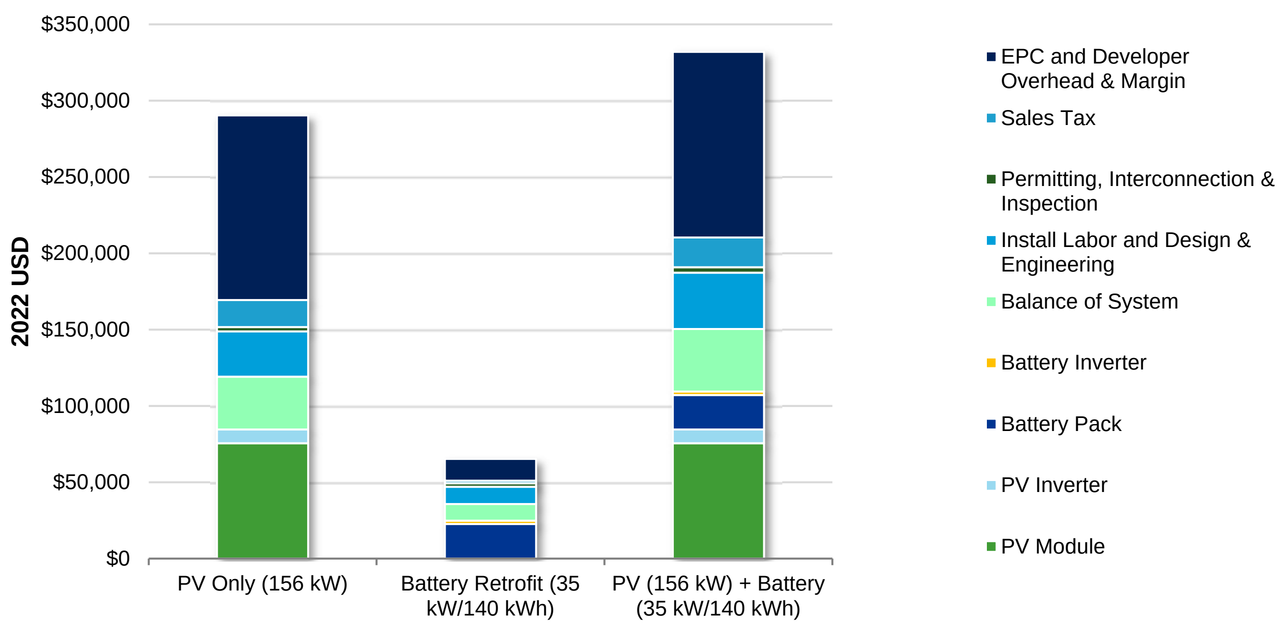


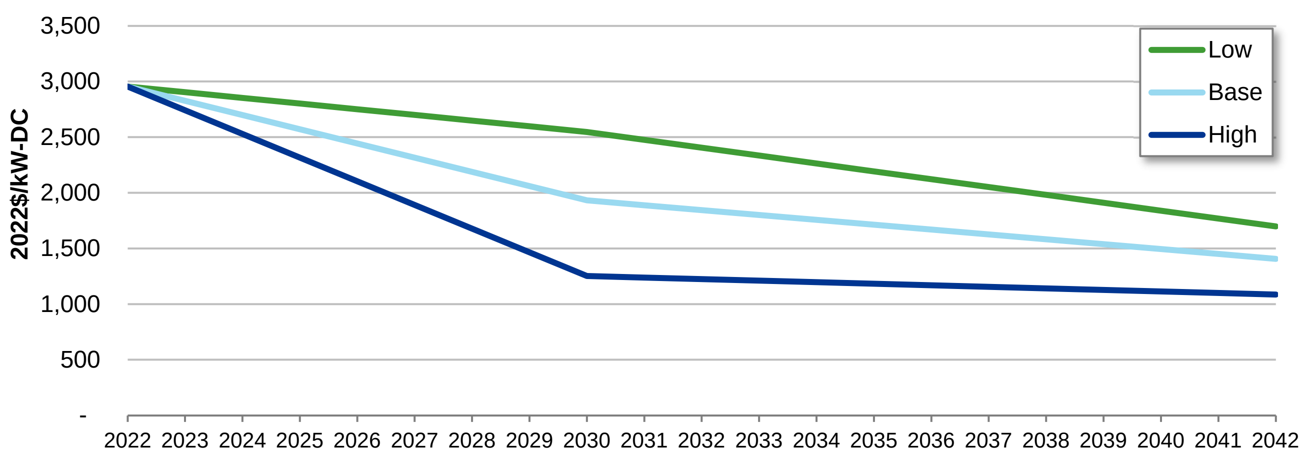
Figure 3-3 Cost of Commercial PV Standalone, Battery Storage Retrofit to Existing PV, and PV + Battery Systems from DNV Bottom-up Cap-Ex Model, Utah



DNV has estimated all CapEx categories for the projects based on Wood Mackenzie's US 2022 H1 cost model, which has been found to be reasonable relative to actual CapEx that DNV has observed on projects it's reviewed in the past. DNV estimated the benchmark CapEx values based on the project capacity, location, and technology assumptions for each state and sector. When technology assumptions were unavailable, DNV made reasonable assumptions. Combined PV + Battery systems were assumed to have cost efficiencies in certain categories that would reduce the total cost of the system when installed at the same time. Cap-Ex categories assumed to have cost efficiencies for combined systems include electrical and structural balance of system, installation labor, design & engineering, permitting, interconnection & inspection costs, customer acquisition costs, supply chain and logistics, and overhead and profit costs.

DNV used a blended version of the NREL Annual Technology Baseline[6] moderate and conservative solar PV and battery energy storage system technology cost forecasts in the base case of this private generation forecast. The average residential and non-residential PV system cost forecasts are presented in Figure 3-4 and Figure 3-5, and the average residential and non-residential battery cost forecasts are shown in Figure 3-6 and Figure 3-7. DNV reviewed the costs presented in the NREL dataset and found that the moderate cost decline forecast for solar PV was much more aggressive than what DNV's national cost models are predicting and what has been seen in the market historically. The technology cost forecast used in the base case has a 37% price decrease in the first 10 years, as opposed to the 50% decrease forecasted in the NREL moderate case.

Figure 3-4 Average Residential Solar PV System Costs, 2023-2042



[6] NREL (National Renewable Energy Laboratory). 2021. 2021 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

Figure 3-5 Average Non-Residential Solar PV System Costs, 2023-2042

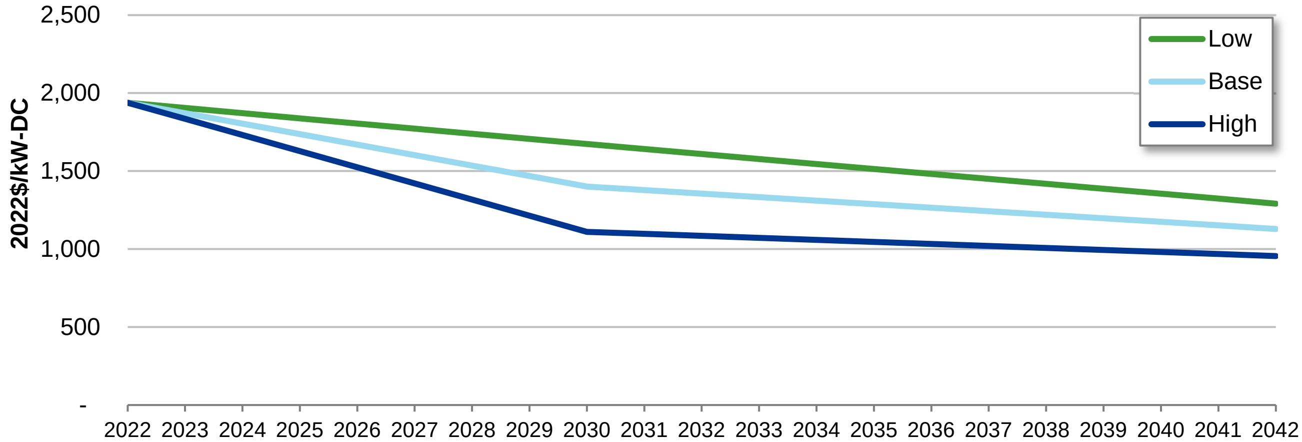


Figure 3-6 Average Residential Battery Energy Storage System (AC-Coupled) Costs, 2023-2042

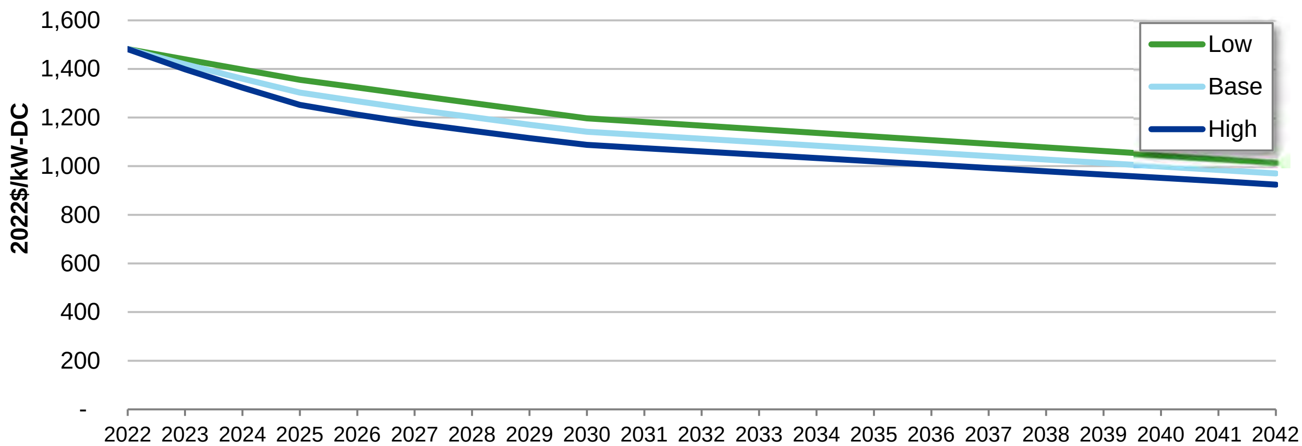
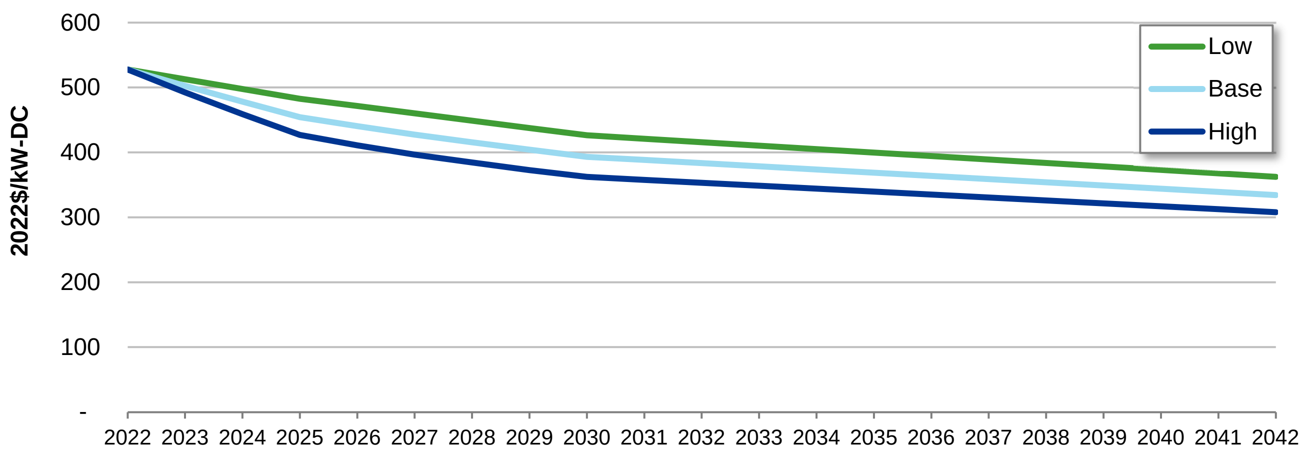


Figure 3-7 Average Non-Residential Battery Energy Storage System (AC-Coupled) Costs, 2023-2042



3.1.2 Small-Scale Wind

Distributed wind technology is a relatively mature DER. Small-scale wind systems typically serve rural homes, farms, and manufacturing facilities due to their size and land requirements. Wind turbines generate electricity by converting kinetic energy in the wind into rotating shaft power that spins an AC generator.

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A. Table 3-4 provides the cost and performance assumptions used in the small-scale wind forecast and the source for each.

Table 3-4 Small Wind Assumptions

Cost & Performance Metric	Units	Residential (20 kW or less)	Commercial (21-100 kW)	Midsize (101-999 kW)	Sources
Installed Cost	2022$/kW	$6,185	$4,686	$3,015	NREL, 2022. Distributed Wind Energy Futures Study. https://www.nrel.gov/docs/fy22osti/82519.pdf
Annual Installed Cost Change	%, 2022-2042	-1.9%			NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Fixed O&M	2022$/kW-yr	$38	$38	$38	NREL, 2022. Distributed Wind Energy Futures Study. https://www.nrel.gov/docs/fy22osti/82519.pdf
Annual Fixed O&M Cost Change	%, 2022-2042	-3.5%	-1.9%	-1.9%	NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Capacity Factor (dependent on state)	%	7.7-10.8%	15.1%-18.5%	15.2%-18.4%	System Advisor Model Version 2021.12.2. National Renewable Energy Laboratory. Golden, CO. https://sam.nrel.gov

3.1.3 Small-Scale Hydropower

Hydroelectric power is an established, mature technology, but small-scale systems are a newer permutation of the technology and therefore are still quite costly compared to other private generation technologies. Small hydro systems generate electricity by transforming potential energy from a water source into kinetic energy that rotates the shaft of an AC generator. Assumptions on system capacity sizes in each state and sector are detailed in Appendix A. Table 3-5 provides the cost and performance assumptions used in the small hydro forecast and the source for each.

Table 3-5 Small Hydro Assumptions

Cost & Performance Metric	Units	Micro-hydro (100 kW or less)	Mini-hydro (100 kW-1 MW)	Sources
Installed Cost	2022$/kW	$5,190	$3,892	International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower"

Annual Installed Cost Change	%, 2022-2042	-0.2%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Fixed O&M	2022$/kW-yr	$208	$156	International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower"
Annual Fixed O&M Cost Change	%, 2022-2042	-1.9%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Capacity Factor	%	45%	45%	International Renewable Energy Agency (IRENA). 2012. "Renewable Energy Cost Analysis: Hydropower"

3.1.4 Reciprocating Engines

Combined heat and power (CHP), or cogeneration, is a mature technology that has been used in the power sector and as a private generation resource for decades. The two most common CHP technologies for commercial and small- to medium-industrial applications are reciprocating engines and microturbines, used to produce both onsite power and thermal energy.

Reciprocating engines are a mature, reliable technology that perform well at part-load operation in both baseload and load following applications. Reciprocating engines can be operated with a wide variety of fuels; however, this analysis assumes natural gas is used to generate electricity as it is the most commonly used fuel in CHP applications. A reciprocating engine uses a cylindrical combustion chamber with a close-fitting piston that travels the length of the cylinder. The piston connects to a crankshaft that converts the linear motion of the piston into rotating motion. Reciprocating engines start quickly and operate on normal natural gas delivery pressures without additional gas compression. The thermal energy output from system operation can be used to produce hot water or low-pressure steam, or chilled water with the additional of an absorption chiller. Typical CHP applications for reciprocating engine systems in the Pacific Northwest include universities, hospitals, wastewater treatment facilities, agricultural applications, commercial buildings, and small- to medium-sized industrial facilities.[7]

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A. Two representative reciprocating engine sizes were used in this analysis based on the ability to meet average customer minimum electric load, ranging from less than 100 kW to 1 MW. Table 3-6 provides the cost and performance assumptions used in the reciprocating engine forecast and the source for each.

Table 3-6 Reciprocating Engine Assumptions

Cost & Performance Metric	Units	Small (100 kW or less)	Medium (100 kW-1 MW)	Sources
Installed Cost	2022$/kW	$4,189	$3,183	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.
Annual Installed Cost Change	%, 2022-2042	-0.5%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/

[7] U.S. Department of Energy Combined Heat and Power and Microgrid Installation Databases (2022). Available at: https://doe.icfwebservices.com/chp

Variable O&M	2022$/MWh	$28	$25	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.
Annual Variable O&M Cost Change	%, 2022-2042	-1.9%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Electric Heat Rate (HHV)	Btu/kWh	11,765	9,721	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.

3.1.5 Microturbines

Microturbines are another CHP application that are commonly used in smaller commercial and inustrial applications. They are smaller combustion turbines that can be stacked in parallel to serve larger loads and provide flexibility in deployment and interconnection at customer sites. Microturbines can use gaseous or liquid fuels, but for CHP applications natural gas is the most common fuel. Therefore for this analysis DNV assumed microturbines will use natural gas to generate electricity and thermal energy at customer sites. Microturbines operate on the Brayton thermodynamic cycle where atmospheric air is compressed, heated by burning fuel and then used to drive a turbine that in turn drives an AC generator. A microturbine can have exhaust temperatures in the range of 500 to 600ºF, which can be used to produce steam, hot water, or chilled water with the additional of an absorption chiller in CHP applications. Microturbine efficiency declines significantly as load decreases, therefore the technology is best suited to operate in base load applications operating at or near full system load. Common microturbine CHP installations in the Pacific Northwestinclude small universities, commercial buildings, small manufacturing operations, hotels, and wastewater treatment facilities.[7]

Assumptions on system capacity sizes in each state and sector are detailed in Appendix A. Two representative microturbine sizes were used in this analysis based on the ability to meet average customer minimum electric load, ranging from less than 100 kW to 1 MW. Table 3-7 provides the cost and performance assumptions used in the reciprocating engine forecast and the source for each.

Table 3-7 Microturbine Assumptions

Cost & Performance Metric	Units	Small (less than 100 kW)	Medium (100 kW-1 MW)	Sources
Installed Cost	2022$/kW	$3,742	$3,686	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.
Annual Installed Cost Change	%, 2022-2042	-0.6%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/
Variable O&M	2022$/MWh	$19	$15	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.
Annual Variable O&M Cost Change	%, 2022-2042	-1.9%		NREL. 2021. "2021 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/

Electric Heat Rate (HHV)	Btu/kWh	13,648	11,566	"A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California." 2019. California Energy Commission.

3.2 Customer Perspectives

Customers' attitudes towards, and general understanding of, private generation technologies, projects, and initiatives currently being promoted in the market today will vary based on a variety of factors covered in this section. DNV has combined internal expertise with an aggregation of customer-focused research from reputable sources to understand overall trends in customer sentiment and insights specifically related to private generation for residential or nonresidential buildings.. Some of the key motivators and barriers to private generation technology adoption are presented in Table 3-8.

Table 3-8 Motivators and Barriers for Private Generation Technology Adoption

TECHNOLOGY	MOTIVATORS	BARRIERS
ALL	• Cost savings • Reducing carbon footprint	• Educational awareness • Proactive involvement from customer • Minimal understanding of technology applications
SOLAR PV	• Cost savings • Reducing carbon footprint • Attractive financing options	• Initial investment • Infrastructure requirements i.e., physical space and roof quality • Perception as a technology for the affluent
BATTERY STORAGE	• Cost savings • Resilience/backup power • likelihood to experience to severe weather • Reduce peak consumption	• Low levels of awareness and understanding • Short duration capability for backup • Limited monetization opportunities • Physical space and roof quality • Initial investment • Limited use cases for storage-only
SOLAR + BATTERY	• Resilience/backup power • ITC applicability window • Maximize solar generation • Cost savings • Reducing carbon footprint	• Initial investment • Infrastructure requirements of solar

Customer adoption of solar, storage, and other PG-related solutions is primarily influenced by financial viability of the overall project and the associated return on investment or payback period. However, while the financial parameters and payment options for a project are certainly an important feature, customers will also face different barriers or motivators that will either encourage or discourage them from adoption despite the financial benefits.

For these reasons, research organizations have typically viewed adoption of new and innovative technologies by customer segments ranging from early adopters and enthusiasts to the majority and the laggards. Some customers may even be considered opposed to the innovation and will never adopt the technology. On the other hand, there also exists a consumer group that will move forward with adoption of DER offerings even when the financial numbers don't show the most desirable ROI or payback. This consumer group is more easilyinfluenced by sales and marketing strategies even when the numbers don't "add up" to a clear economic play. The following sections will provide further insights on how customer awareness, knowledge of energy costs and systems, and incentives can impact customer adoption of PG technologies.

3.2.1 Customer Awareness

While DERs, the term most commonly used to describe PG technologies is a common term within the energy industry, it is not commonly understood by the average consumer. Less than 10% of residential customers are clear on exactly what the term means and how it applies to them. Consumers are lacking a sound understanding of how DERs work, the tangible benefits they provide, and how they would operate within a home or business.

Customer education to build awareness is likely to lead to more growth of PG. Educational outreach and marketing should focus on accessible, feasible use-cases for technology applications in “real-world” settings that customers can relate to and see themselves using. Customers have a desire to improve their understanding of PG opportunities by obtaining quality information – most prefer their electricity provider as the source – about the savings potential of these technologies and details on how they work. [8]

3.2.2 Motivating Factors for Adoption

The primary motivators that prompt customers to consider implementing PG technologies are how much savings they can realize through a project and the level of incentives being awarded. Second to these financial motivators, customers are interested in PG opportunities as a method of reducing their environmental impact. Customers who are aware of PG opportunities often have a curiosity and desire to increase their understanding of the opportunities available to them as committing to a PG system or product requires the customer to have a greater level of involvement in their electricity generation, consumption, and management. While understanding and awareness of PG is a clear barrier to adoption, customers have the desire to obtain information to help them better understand these technologies. Energy providers can prioritize informative, engaging communication to increase the customers’ understanding of DER opportunities, thus increasing their likelihood of adoption and participation.[7]

3.2.3 Barriers to Adoption

Trust and finances are common barriers to PG adoption– customers are often skeptical that these projects will perform as advertised and save the amount of money that is claimed. Customers need quality information to help them validate the investment in certain new technologies or programs that they do not have experience with. If the customer’s goal for a PG system is to save money and they express the need to understand how much money the projects will save, accurate information needs to be available to prove those cases to the customer. Successful implementation of PG technologies and solutions will require changing the behavior and perception of a large portion of the customers.[7]

3.2.4 Other Considerations

Customers who participate in demand response programs are more likely to own a hybrid or electric vehicle, energy management system (EMS), or solar + storage system than customers who do not participate in demand response programs. A foundational piece for growing participation in DER initiatives can be first focusing on demand response programs as a way for customers to get started on their clean energy journeys. This concept of “DER stacking” enables a utility to prioritize targeting customers who are already participating in some form of demand response or PG-related program, thus giving the customer a more holistic solution for their energy management and consumption.[7]

[8] SECC (Smart Energy Consumer Collaborative). 2019. Distributed Energy Resources: MEETING CONSUMER NEEDS. Pages 7 – 13.

3.2.5 Incentives Overview

Since the passing of the Inflation Recovery Act of 2022, the federal Investment Tax Credit (ITC) has been extended past its original expiration date for ten years. For facilities beginning construction before January 1, 2025, the bill will extend the ITC for up to 30 percent of the cost of installed equipment for ten years and will then step down to 26 percent in 2033 and 22 percent in 2034. For projects beginning construction after 2019 that are placed in service before January 1, 2022, the ITC would be set at 26 percent. In addition to the new federal ITC schedule for generating facilities, the updated ITC includes credits for standalone energy storage with a capacity of at least 3 kWh for residential customers and 5 kWh for non-residential customers. The bill also includes a 5-year MACRS depreciation schedule for non-residential energy storage. The federal tax credits in Table 3-9 were included in the economic analysis of all private generation forecast scenarios.

DNV

Table 3-9 Federal Investment Tax Credits for DERs

Cells in green represent the transition to a technology-neutral ITC for clean energy technologies with 0 gCO2e emissions per kWh, under section 48D.

INCENTIVE	SYSTEM SIZE (KW)	TECHNOLOGY	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035+
Residential/ Business ITC	< 1000	PV	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Residential/ Business ITC	< 1000	Energy Storage	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	26%	0%
Residential/ Business ITC	< 1000	Small Wind	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Business ITC	< 1000	Microturbines	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Business ITC	< 1000	Reciprocating Engines	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%
Business ITC	< 150	Small Hydro (hydropowered dams)	30%	30%	30%											
Business ITC	< 25	Small Hydro (Hydrokinetic pressurized conduits)	30%	30%	30%											
Business ITC	< 1000	Small Hydro				30%	30%	30%	30%	30%	30%	30%	30%	26%	22%	0%

A summary of the state incentives included in the economic analysis are provided below in Table 3-10.

Table 3-10 State Incentives for DERs

STATE	RESIDENTIAL		NON-RESIDENTIAL
Oregon[9]	**PV-Only:** Up to $5,000	**PV + Battery:** Up to $2,500	$0.20/watt up to $20,000
Utah[10]	**PV:** 2022—$800 2023—$400	**Non-PV:** Up to $2,000	Up to 10 percent of the eligible system cost or up to $50,000*
Idaho[11]	Annual maximum of $5,000, and $20,000 over four years**		None
California	None		None
Washington	None		None
Wyoming	None		None

* Solar PV, wind, geothermal, hydro, biomass or certain renewable thermal technologies
** Mechanism or series of mechanisms using solar radiation, wind or geothermal resource

3.3 Current Private Generation Market

To date, about 99 percent of existing private generation capacity installed in PacifiCorp's service territory is PV or PV + Battery[12]. To inform the adoption forecast process, DNV conducted an in-depth review of the other technologies and did not find any literature to suggest that they would take on a larger share of the private generation market in the Company's service territory in the future years of this study. Figure 3-8 shows the current share of private generation capacity by technology in each of PacifiCorp's six-state service territory.

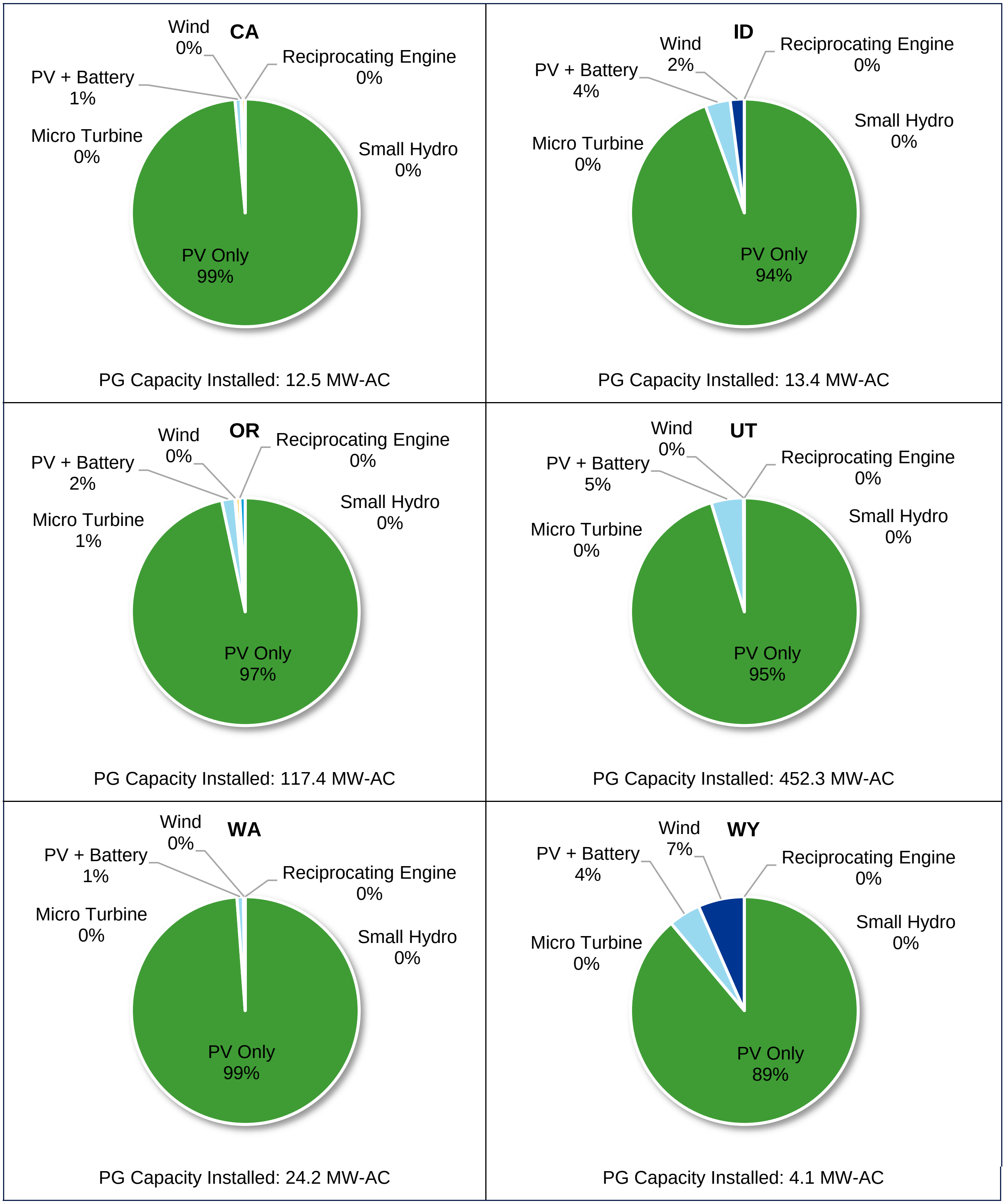
[9] Incentives provided through Energy Trust of Oregon (Solar for Your Home, Solar Within Reach and Solar for Your Business) and Oregon Department of Energy (Solar + Storage Rebate Program for Low-Moderate Income and Non-Income Restricted Homeowners). https://energytrust.org/programs/solar/ https://www.oregon.gov/energy/Incentives/Pages/Solar-Storage-Rebate-Program.aspx

[10] Incentives provided through Utah Office of Energy Development Renewable Energy Systems Tax Credit. https://energy.utah.gov/tax-credits/renewable-energy-systems-tax-credit/

[11] Incentives provided through the State of Idaho Renewable Alternative Tax Deduction. https://legislature.idaho.gov/statutesrules/idstat/title63/t63ch30/sect63-3022c/

[12] PacifiCorp private generation interconnection data as of February 2022.

Figure 3-8 Historic Cumulative Installed Private Generation Capacity by Technology, YTD



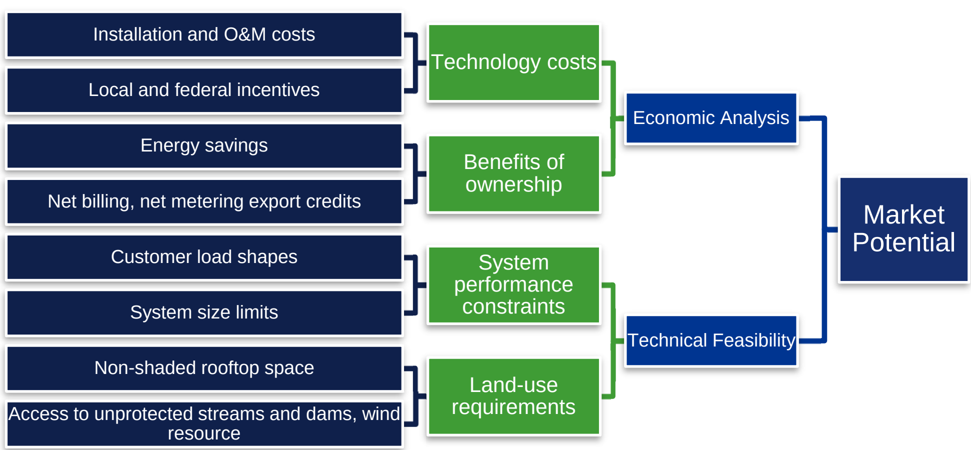
Section 3.4.3 describes in further detail how the historic private generation adoption data is used in the private generation forecast modelling process.

3.4 Forecast Methodology

DNV combined technical feasibility characteristics of the identified PG technologies and potential customers with an economic analysis to calculate cost-effectiveness metrics for each technology, within each state that PacifiCorp serves, over the analysis timeframe. DNV then used a bass diffusion model to estimate customer PG adoption based on technical and economic feasibility and incorporated existing adoption of each PG technology by state and customer segment as an input to the adoption model.

Technical feasibility characteristics were used to identify the potential customer base that could technically support the installation of a specific PG technology, or the maximum, feasible, adoption for each technology by sector. These factors included overall PG metrics such as average customer load shapes and system size limits by state, and specific technology factors such as estimated rooftop space and resource access based on location (for hydro and wind resource applicability). Simple payback was used in the customer adoption portion of the model as an input parameter to bass diffusion curves that determined future penetration of all PG technologies. Figure 3-9 provides a visual representation of how different inputs were used in different portions of the model. Additional detail on the economic and adoption approaches used in this analysis are provided in the subsequent sections.

Figure 3-9 Methodology to Determine Market Potential of Private Generation Adoption



3.4.1 Economic Analysis

The economic analysis portion of overall customer adoption was used a key factor in the Bass diffusion model that calculated future PG adoption. DNV used simple payback as the preferred method of estimating economic viability for PG based on customer perspectives given its widespread use in similar adoption analyses, ability to reflect customer decision making in forecasting efforts, and ease of estimation.

DNV developed a behind-the-meter net economic perspective that includes, as costs, the acquisition and installation costs for each technology less the impact of available incentives and, as benefits, the customer's economic benefits of ownership such as energy and demand savings and export credits. For this study we assumed that the current net metering or net billing policies and tariff structures in each state continued throughout the study horizon. This resulted in the model incorporating benefits associated with net metering in Oregon, Washington, and Wyoming and net billing in Utah and California. We assumed customer's in Idaho would accrue benefits based on the net billing policy in Utah throughout the study. DNV has been following the ongoing Idaho Public Utilities Commission (PUC) review of Idaho Power Company's (Idaho Power) Value of Distributed Resources (VODER) study filing. Idaho Power's VODER study found that excess power generated by rooftop solar owners is worth less than half of retail rate energy and serves as the basis of Idaho Power's proposal for a new compensation rate structure for solar owners. If approved by the Idaho PUC, Idaho Power's proposed compensation rate structure would more closely resemble the current net billing structure in place in Utah[13] and DNV assumed PacifiCorp would implement a similar rate structure in their Idaho territory.

A detailed breakdown of the simple payback calculation and different elements is shown below.

$$\boldsymbol{Simple\ Payback} = \frac{Cumulative\ Net\ Costs}{Cumulative\ Net\ Benefits}$$

$$\boldsymbol{Cumulative\ Net\ Costs} = (Upfront\ System\ Cost - Year\ One\ Incentives) + NPV(Annual\ O\&M\ Costs + Annual\ Fuel\ Costs)$$

$$\boldsymbol{Cumulative\ Net\ Benefits} = NPV(MACRS\ Savings + \ Self\ Consumption\ Savings + Export\ Credits + Peak\ Demand\ Savings)$$

DNV also used an annual hourly profile analysis to estimate electric bill savings and excess generation for each PG technology by customer segment. This analysis used hourly generation and customer load profiles, and tiered, time-of-use (TOU), and peak demand rates for each customer and technology permutation. DNV integrated the energy savings, excess generation, and peak demand benefits into the lifetime simple payback estimation using customer load and individual rate forecasts provided by PacifiCorp. A full breakdown of all inputs used in the economic analysis is provided in Table 3-11 below.

Table 3-11 PG Forecast Economic Analysis Inputs

INPUT TYPE	COST / BENEFIT CATEGORY	SOURCE
TECHNOLOGY COST DATA – INSTALLED COST	PG cost data compiled in $/kW (AC & DC) – used in determining year one installed system costs	DNV
TECHNOLOGY COST DATA – ANNUAL O&M	PG fixed ($/kW) & variable ($/kWh) O&M data – used in determining annual system costs	DNV
FUEL COST DATA	Natural gas cost data ($/MMBtu)	EIA Annual Energy Outlook 2022
TECHNOLOGY GENERATION PROFILES	Hourly generation profiles for each PG technology by state – used in calculating self-consumption savings, excess generation credits, and peak demand savings	DNV
CUSTOMER LOAD PROFILES	Hourly average customer load profiles by state – used in calculating self-consumption savings, excess generation credits, and peak demand savings	PacifiCorp

[13] As of December 19, 2022, the Idaho Power VODER study has been approved by the Idaho PUC. https://puc.idaho.gov/Fileroom/PublicFiles/ELEC/IPC/IPCE2222/OrdNotc/20221219Final_Order_No_35631.pdf

INPUT TYPE	COST / BENEFIT CATEGORY	SOURCE
CUSTOMER RATES	Customer tiered, TOU, and peak demand rates by size, segment, and state – used in calculating self-consumption savings, excess generation credits, and peak demand savings	PacifiCorp
TECHNOLOGY COST FORECASTS	PG cost data forecasts for installed system costs and annual O&M costs – used in determining year one installed system costs and future year annual system costs	NREL ATB
CUSTOMER & LOAD FORECASTS	Individual customer count and load (kWh) forecasts by segment and state – used in calculating future year system costs and benefits	PacifiCorp
CUSTOMER RATE FORECASTS	Rate forecasts applied to each customer segment – used in calculating future year self-consumption savings, excess generation credits, and peak demand savings	EIA Annual Energy Outlook 2022

DNV calculated simple payback for each PG technology (solar PV, solar PV + battery, wind, hydro, reciprocating engines, and microturbines) by applicable individual customer segments (residential, commercial, industrial, and irrigation) for each installation year in the analysis timeframe (2023 – 2035). These payback results were combined with technical feasibility by customer segment and integrated into the bass diffusion adoption model to determine annual PG penetration throughout PacifiCorp's territory.

3.4.2 Technical Feasibility

The maximum amount of technical feasible capacity of private generation was determined individually for each technology considered in the private generation forecast. Each technology was generally limited by customer access factors, system size limits, and energy consumption. The customer load shapes, provided by PacifiCorp, were used to calculate annual energy use (kWh) cutoffs used in identifying the total number of customers that could technically support the installation of a specific PG technology. Other data sources specific to each technology were used to determine the amount of capacity that can be physically installed within PacifiCorp's service territory, such as:

- Hydropower potential data and environmental attributes for all HUC10 watersheds in PacifiCorp's service territory[14]
- Building rooftop hosting area and suitability for solar PV[15]
- Wind resource potential data by state[16]

[14] Kao, Shih-Chieh, Mcmanamay, Ryan A., Stewart, Kevin M., Samu, Nicole M., Hadjerioua, Boualem, Deneale, Scott T., Yeasmin, Dilruba, Pasha, M. Fayzul K., Oubeidillah, Abdoul A., and Smith, Brennan T. New Stream-reach Development: A Comprehensive Assessment of Hydropower Energy Potential in the United States. United States: N. p., 2014. Web. doi:10.2172/1130425.

[15] Gagnon, P., R. Margolis, J. Melius, C. Phillips, and R. Elmore. 2016. Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment. NREL/TP-6A20-65298. Golden, CO: National Renewable Energy Laboratory.

[16] Draxl, C., B.M. Hodge, A. Clifton, and J. McCaa. 2015. "The Wind Integration National Dataset (WIND) Toolkit." Applied Energy 151: 355366.

3.4.3 Market Adoption

DNV modeled market adoption using Bass diffusion curves customized to each state, technology, and sector. The Bass diffusion model was developed in the 1960s and is widely used to model market adoption over time.

The formula for new adoption of a technology in year t is given by[17]

$$s(t) = m\,\frac{(p+q)^2}{p}\,\frac{e^{-t(p+q)}}{(1+\frac{q}{p}e^{-t(p+q)})^2}$$

<u>Where:</u>

s(t) is new adopters at time *t*

m is the ultimate market potential

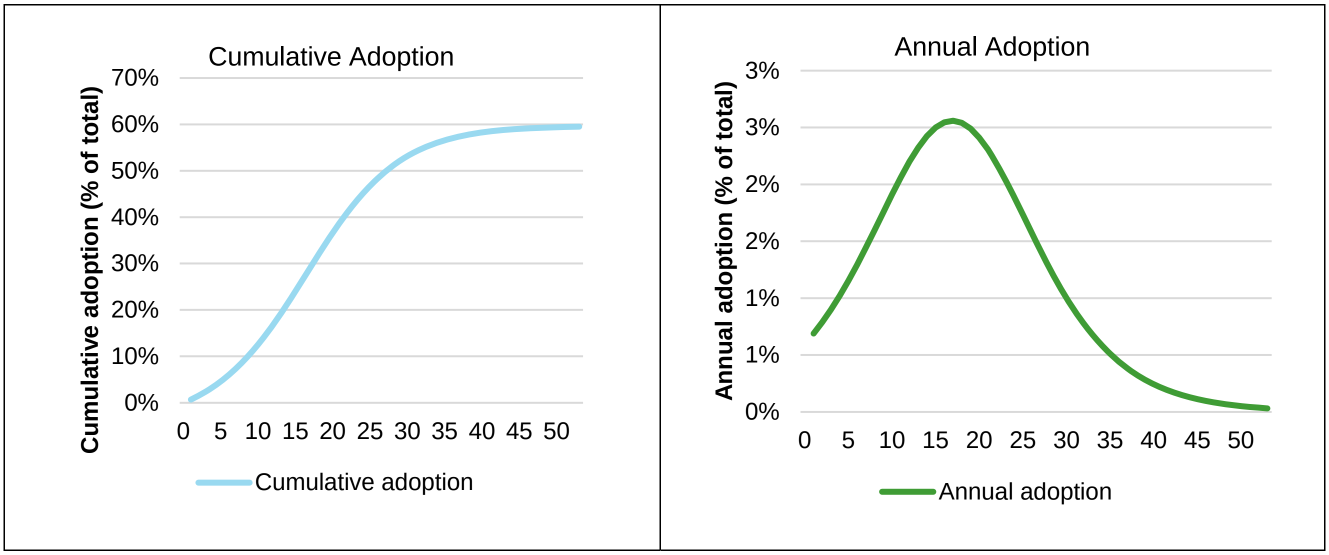
p is the coefficient of innovation

q is the coefficient of imitation

t is time in years

Figure 3-10 shows a generalized Bass diffusion curve. The cumulative adoption curve takes a characteristic “S” shape with a new unknown and unproven technology having relatively slow adoption that accelerates over time as the technology becomes more familiar to a wider segment of the population. As the pool of potential buyers who have not yet adopted the technology shrinks, the rate of adoption (as a percent of the total pool of potential adopters) decreases until eventually everyone who will adopt has adopted. The corresponding chart shows the rate of annual new adoption.

Figure 3-10 Bass Diffusion Curve Illustration



In the illustration, the cumulative curve approaches 60% market penetration asymptotically, corresponding to the value of *m* (ultimate market potential) that we chose for the illustration. For our adoption models, we tied the value of *m* to payback,

[17] Bass, Frank (1969). "A new product growth for model consumer durables". Management Science. 15 (5): 215–227

following Sigrin and Drury's[18] survey findings on willingness to pay for rooftop photovoltaics based on payback. Because payback varied by technology, state, and sector, so did the Bass diffusion curve.

Due to regional and sectoral differences, we made significant adjustments to the willingness-to-adopt curves to better align with the observed relationship between historic cost effectiveness and current market adoption by technology, state, and sector in PacifiCorp's service territory. Based on PacifiCorp data on current levels of PG adoption, Utah in particular showed higher adoption than published willingness-to-pay curves would suggest, which we believe may be due to regional variation in how customers value resilience. To account for this variation across states, we developed three willingness-to-adopt curves to capture observed state variation. Table 3-12 shows which willingness-to-adopt curve was used for solar for each state and sector. Current adoption for the other modeled technologies was too low to discern variation across state, so we assumed average propensity to adopt for wind, small hydro, reciprocating engines and microturbines.

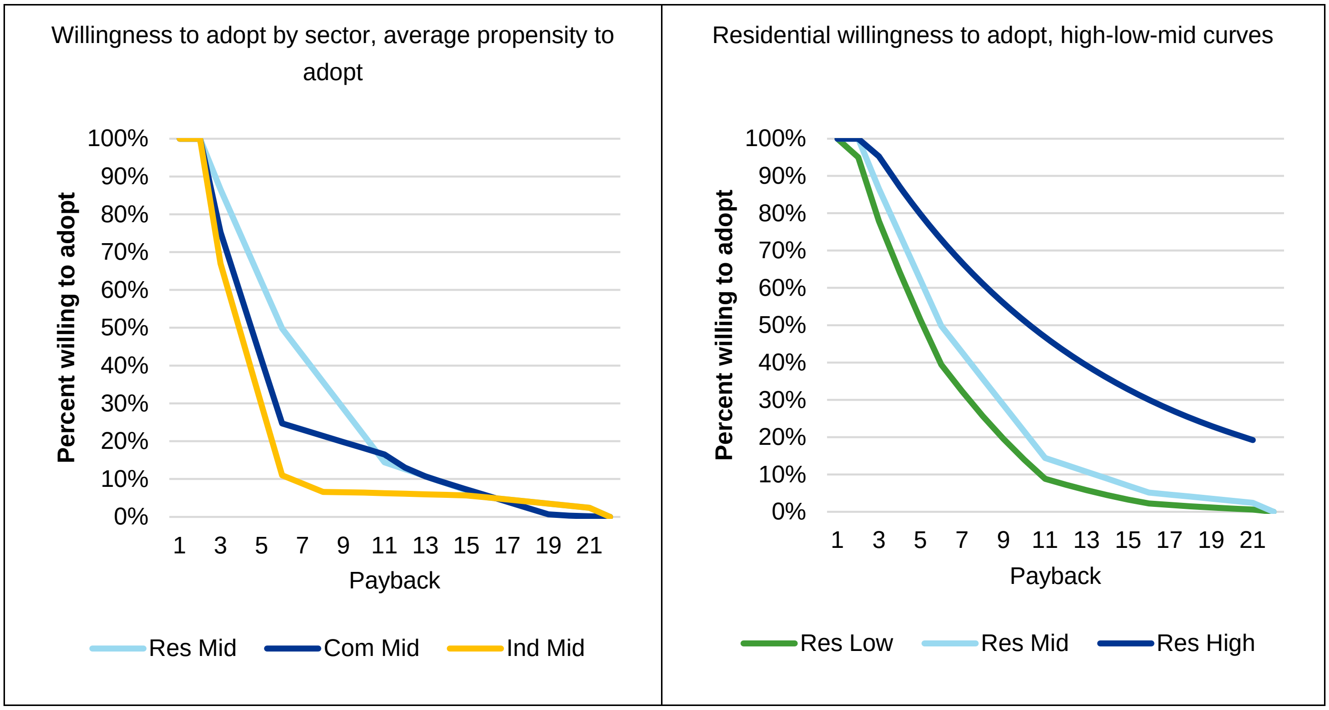
Table 3-12 Solar Willingness-to-Adopt Curve used by State and Sector

AVERAGE PROPENSITY TO ADOPT	HIGH PROPENSITY TO ADOPT	LOW PROPENSITY TO ADOPT
• California residential, commercial, irrigation • Idaho residential • Oregon residential • Washington all sectors	• Utah all sectors • Oregon commercial, industrial, irrigation	• Wyoming all sectors • Idaho commercial, industrial, irrigation • California industrial

Figure 3-11 shows the willingness-to-adopt curves for residential, commercial, and industrial sectors assuming an average propensity to adopt (the "Mid" case). There was too little irrigation adoption to assess the sector independently, so we used the commercial curves for the irrigation sector. The right-hand chart in Figure 3-11 shows the high, mid, and low adoption curves for the residential sector only. The high and low curves for the other sectors show similar variation.

[18] Sigrin, Ben and Easan Drury. 2014. Diffusion into New Markets: Economic Returns Required by Households to Adopt Rooftop Photovoltaics. Energy Market Prediction: Papers from the 2014 AAAI Fall Symposium

Figure 3-11 Willingness to Adopt Based on Technology Payback



The willingness-to-adopt curves established a different *m* parameter for each diffusion curve. In addition to varying by technology, state, and sector, *m* also changed over time due to changing payback resulting from changing technology costs, incentives, and tax credits, among other economic factors).

The timing of our modeled adoption also varied, as we set t_0 for each diffusion curve based on the earliest adoption of each technology by state and sector. For example, the first residential PV installed in PacifiCorp's Oregon service territory was in 2000, while the first commercial PV installation in its Idaho service territory wasn't until 2010. For technology/state/sectors where there is currently no adoption, we assumed that the first adoption would occur in 2023.

The *p* and *q* parameters of the Bass diffusion curves were calibrated so that the predicted cumulative adoption from t_0 through 2021 was equal to the current market penetration of each technology by state and sector (we fixed the relationship between *p* and *q* at $q = 10p$ to make it possible to solve for p). For technology/state/sectors where there is currently no adoption, we assumed average values for *p* and *q*.

The result of this process were Bass diffusion curves customized for each technology, state, and sector that also accounted for variation in willingness-to-adopt as cost effectiveness changes over time. The calibrated curves show some segments still in the very early phases of adoption, while other markets are more mature. Our forecast of annual adoption reflects all of these differences.

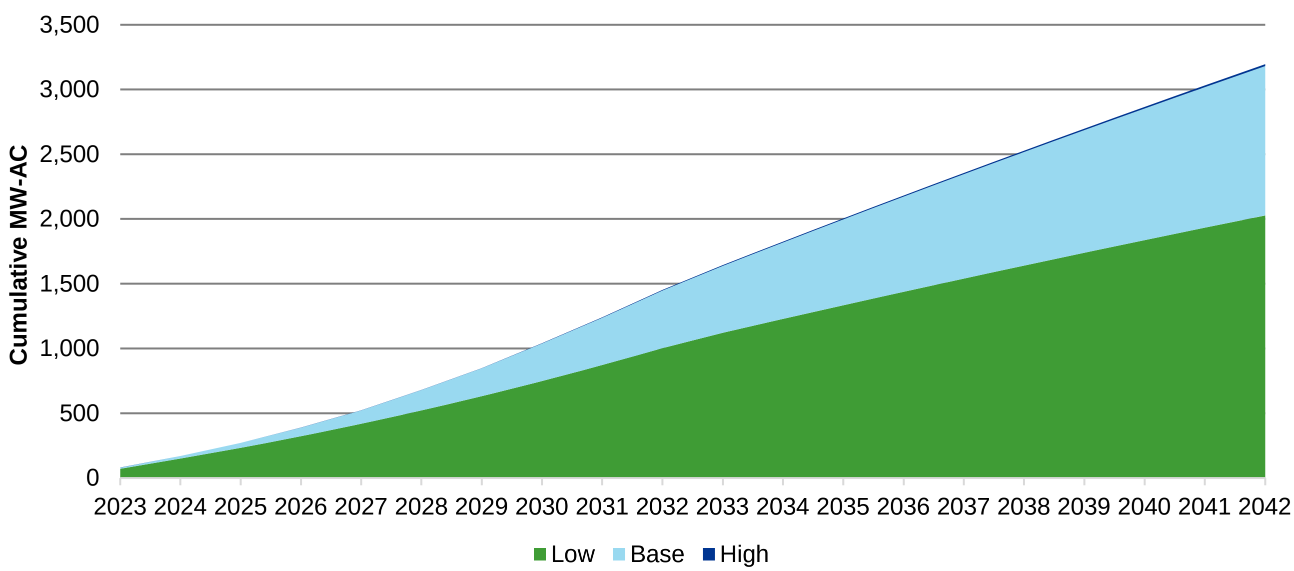
4 RESULTS

In the base case scenario, DNV estimates 3,181 MW of new private generation capacity will be installed in PacifiCorp's service territory over the nest twenty years (2023-2042). Figure 4-1 shows the relationship between the base case and low and high case scenarios. The low case scenario estimates 2,028 MW of new capacity over the 20-year forecast period—compared to base case, retail rates increase at a slower rate and technology costs decrease at a slower rate. In the high case, retail rates increase at a faster rate and technology costs decrease at a faster rate—this results in 3,196 MW of new private generation capacity installed by 2042.

Table 4-1 Cumulative Adopted Private Generation Capacity by 2042, by Scenario

SCENARIO	CUMULATIVE CAPACITY (2042 MW-AC)
Base	3,181
Low	2,028
High	3,196

Figure 4-1 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), 2023-2042



The sensitivity analysis showed a much greater margin of uncertainty on the low side than the high side. The Inflation Reduction Act of 2022 (IRA) extends tax credits that for private generation that create very favorable economics for adoption, and those are embedded in the base case. We therefore limited our upper bound forecast to lower technology costs and higher retail electricity rates, and these produced only a small boost to adoption for technologies that were already cost effective under the IRA. In contrast, when we modelled our lower bound, we found that the decreases in cost effectiveness were enough to tamp down adoption. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of private generation despite incentives being unchanged. The low case forecast is 36% less than the base case, while the high case cumulative installed capacity forecasted over the 20-year period is just 0.5% greater than the base case.

Figure 4-2   Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, Base Case

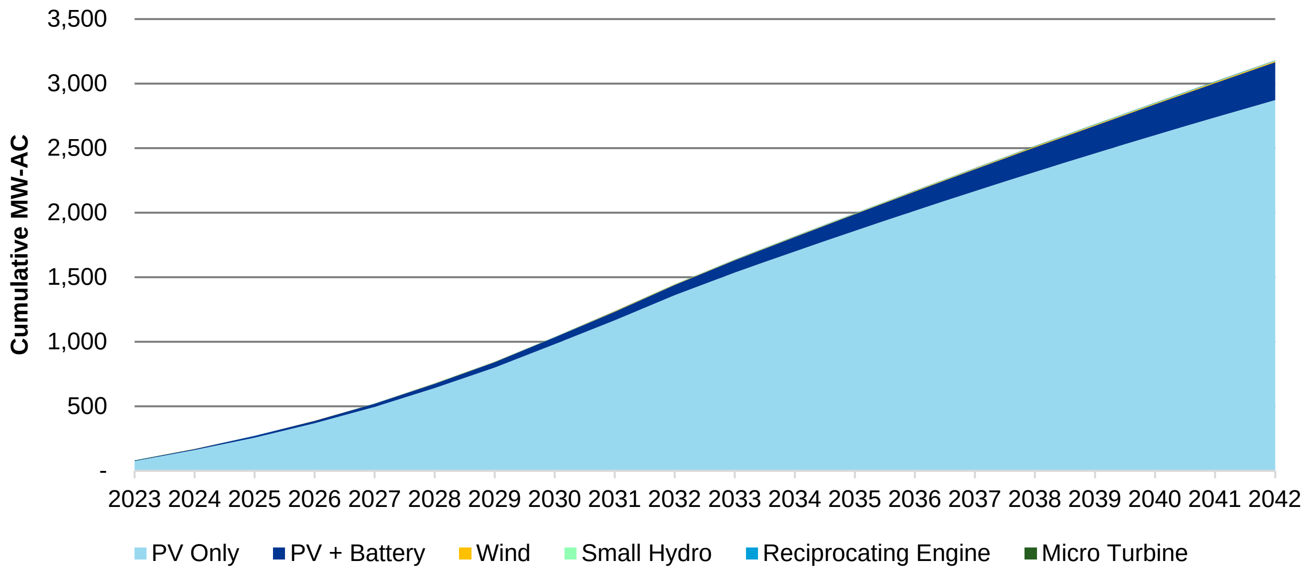


Figure 4-3   Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, Low Case

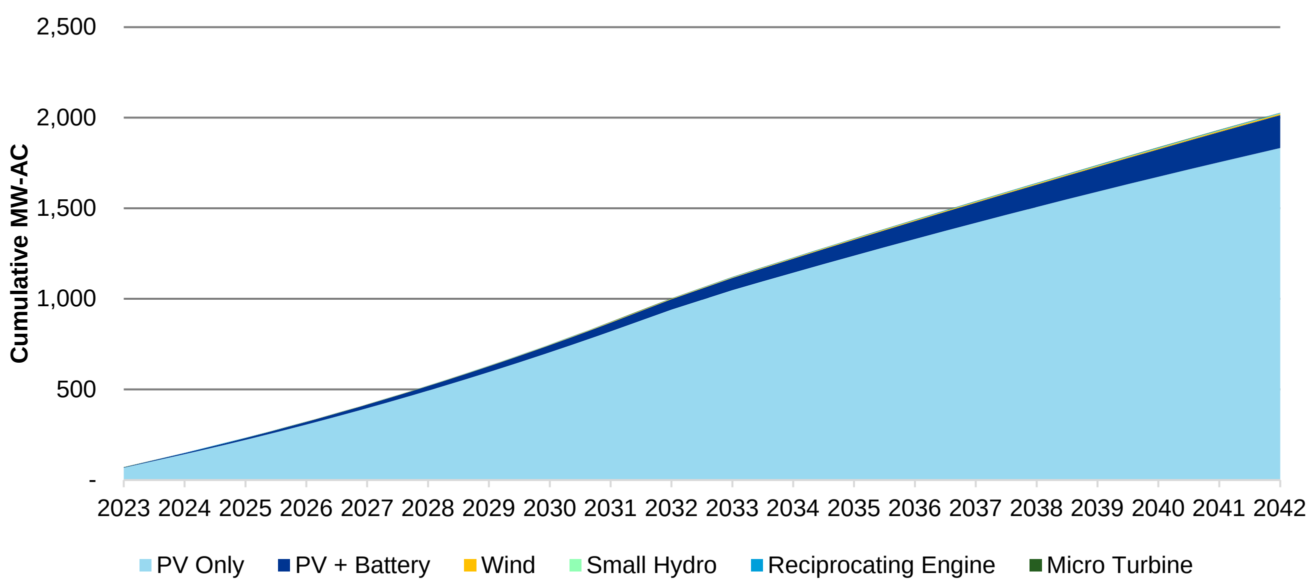
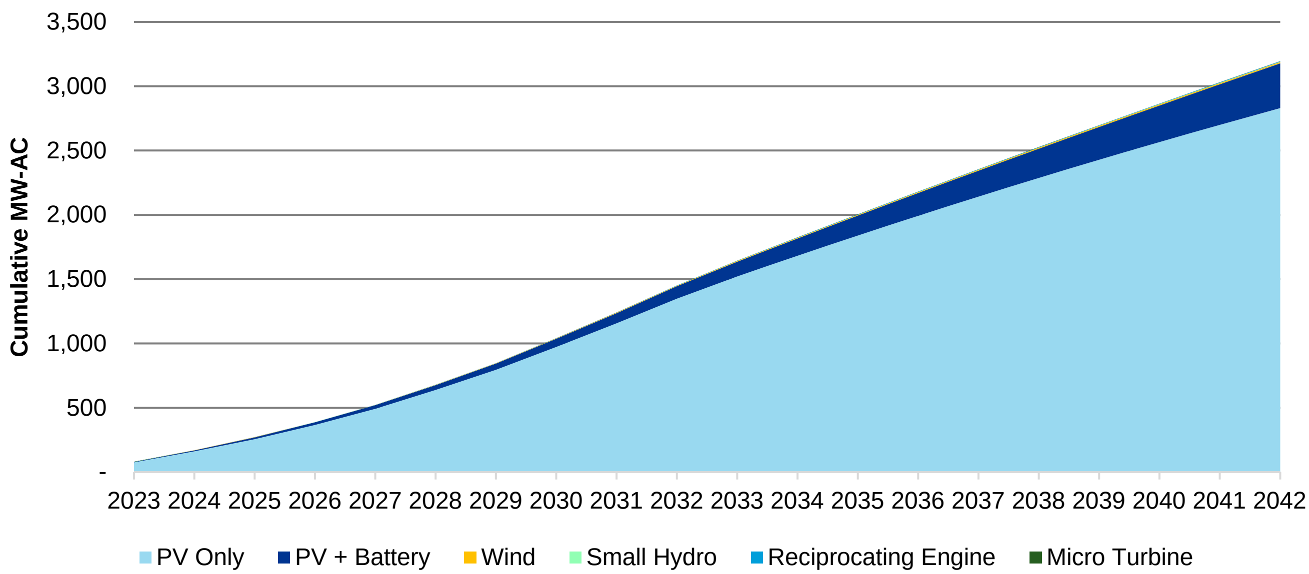


Figure 4-4 Cumulative New Capacity Installed by Technology (MW-AC), 2023-2042, High Case



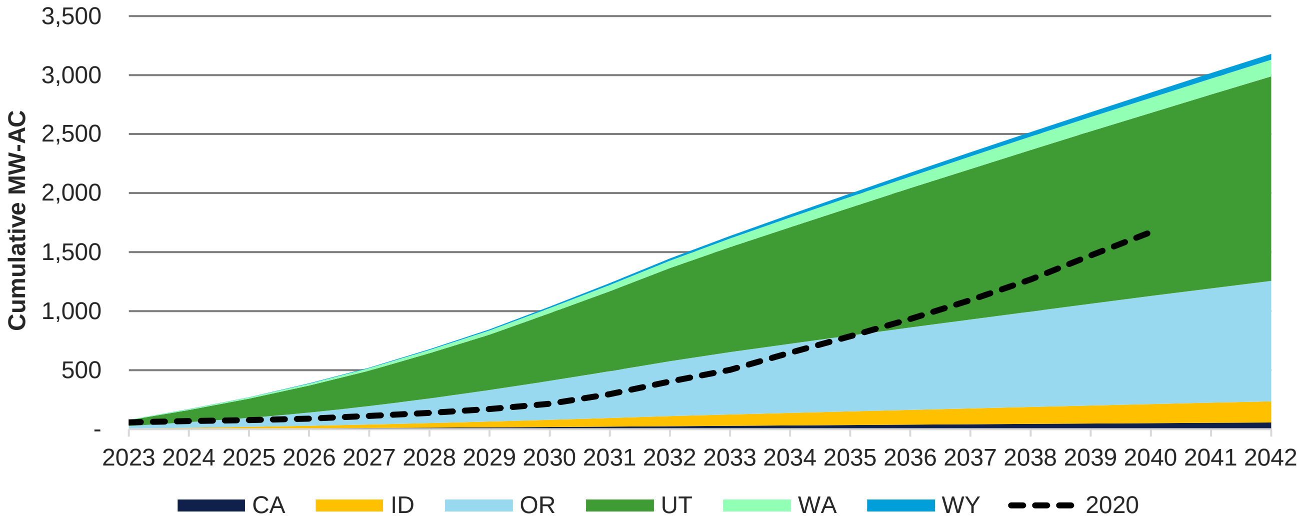
4.1 Generation Capacity Results by State

The following sections present the results by state for each forecast scenario. Additional exhibits for total PV capacity forecasted are provided by sector. PV Only and PV + Battery capacity make up at least 95% of each states' projected private generation capacity, so providing results for the other technologies by sector would not provide useful context to the results. The full set of results by state, sector, and new/existing construction for the forecasts is provided in Appendix B.

Figure 4-5 shows the base case forecast by state, compared to the previous (2020) study's total base case forecast[19]. This figure indicates that Utah and Oregon will drive most PG installations over the next two decades, which is to be expected given these two states represent the largest share of PacifiCorp's customers and sales. The base scenario estimates approximately 1,447 MW of new capacity will be installed over the next 10 years in PacifiCorp's territory—55% of which is in Utah, 32% in Oregon, and 6% in Idaho. Since the 2020 study, the federal Investment Tax Credit (ITC) has been extended for ten years at its original base rate levels and expanded to include energy storage. The tax credit increase and extension lowered the customer payback period for all technologies, making the customer economics of this study's base case more similar to the previous study's high case. In addition to the change in customer economics, projected PV capacity is expected to grow at a faster rate in the early years and at a slower rate towards the end of the forecast period. The key drivers of these differences include larger average PV system sizes, decreases in PV + Battery costs, and the maturity of rooftop PV technology. The adoption model DNV developed for this study was calibrated to existing levels of technology adoption for each state and sector. Technology adoption follow an S-curve with adoption initially increasing at an increasing rate, but eventually passing an inflection point where adoption continues to increase at a decreasing rate.

[19] Cumulative capacity is adjusted to account for the difference in the forecast starting years (2021 in the previous study, versus 2023 in this study). Source: Navigant. 2020. "Private Generation Long-Term Resource Assessment (2021-2040)"

Figure 4-5 Cumulative New Capacity Installed by State (MW-AC), 2023-2042, Base Case



4.1.1 California

Customers in PacifiCorp's service territory in northern California are projected to install about 57 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is about 1% greater than the base case and the low projection is 24% less than the base case, or 57.4 MW and 43 MW, respectively.

California does not currently have any state incentives available for private generation, and uses a net billing structure for DER compensation. The residential sector has the largest share of the private generation capacity, ranging from 59% in the low case to 67% in the high and base cases. The next largest share of the capacity is forecasted in the commercial sector, ranging from 31% in the low case to 24% in the base and high cases.

Figure 4-6 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), California, 2023-2042

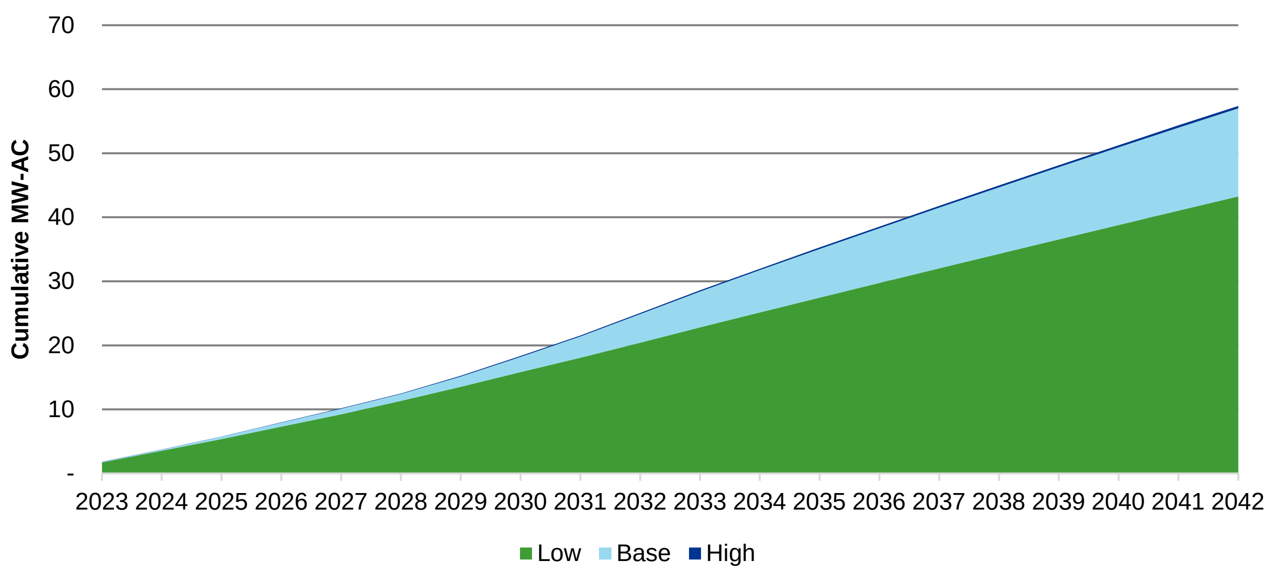


Figure 4-7 Cumulative New Capacity Installed by Technology (MW-AC), California Base Case, 2023-2042

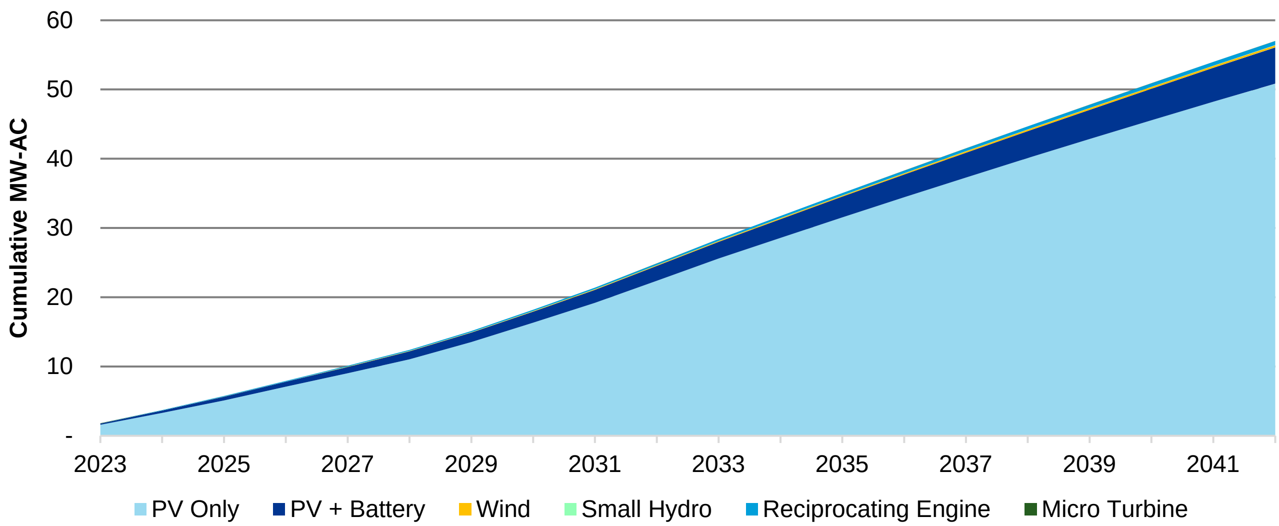


Figure 4-8 Cumulative New Capacity Installed by Technology (MW-AC), California Low Case, 2023-2042

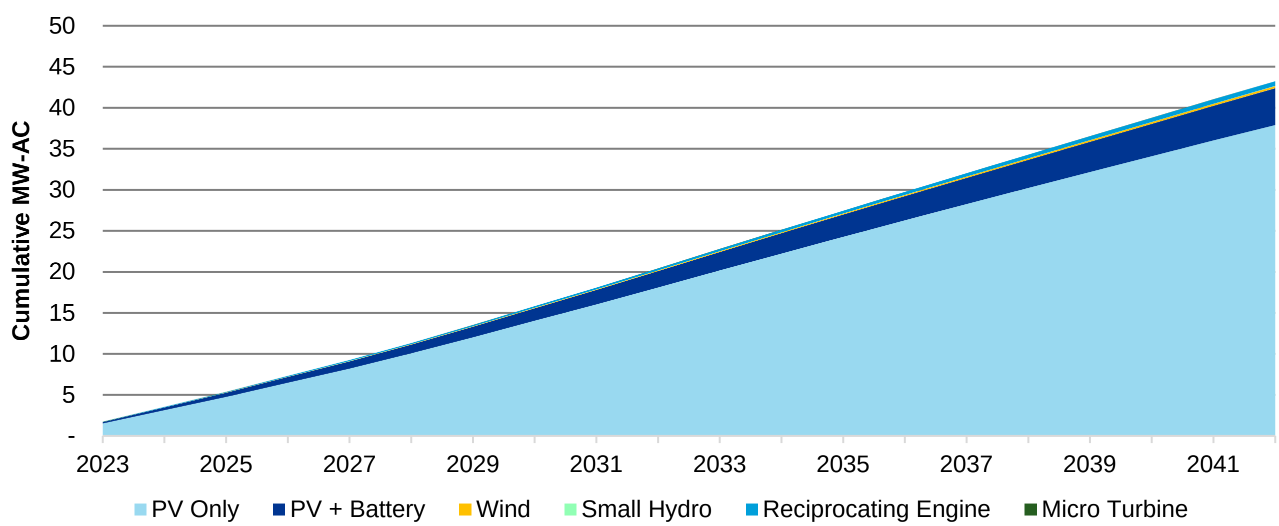
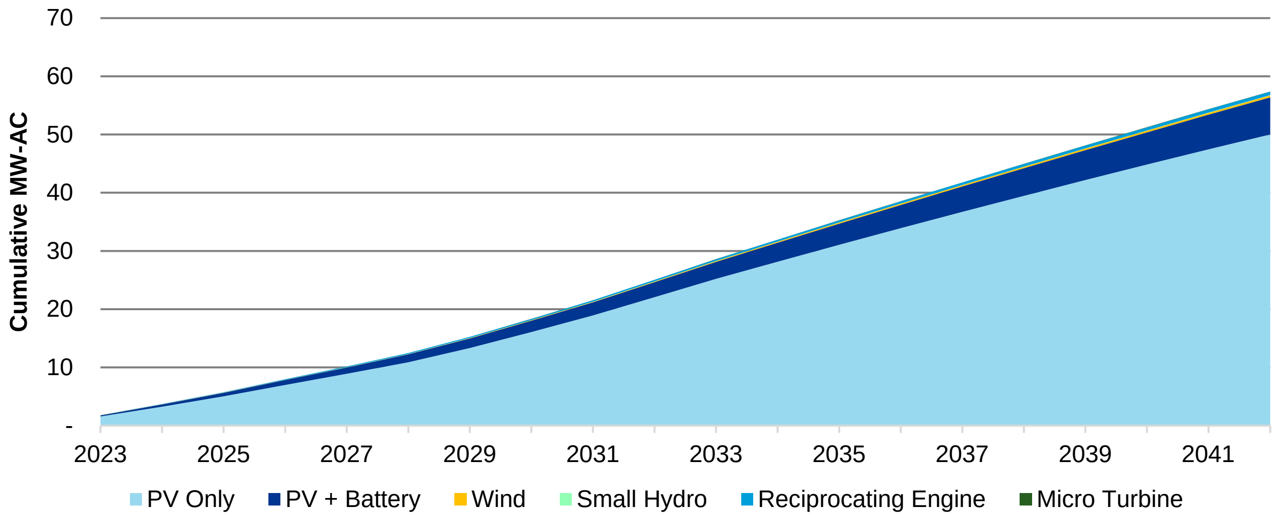


Figure 4-9 Cumulative New Capacity Installed by Technology (MW-AC), California High Case, 2023-2042

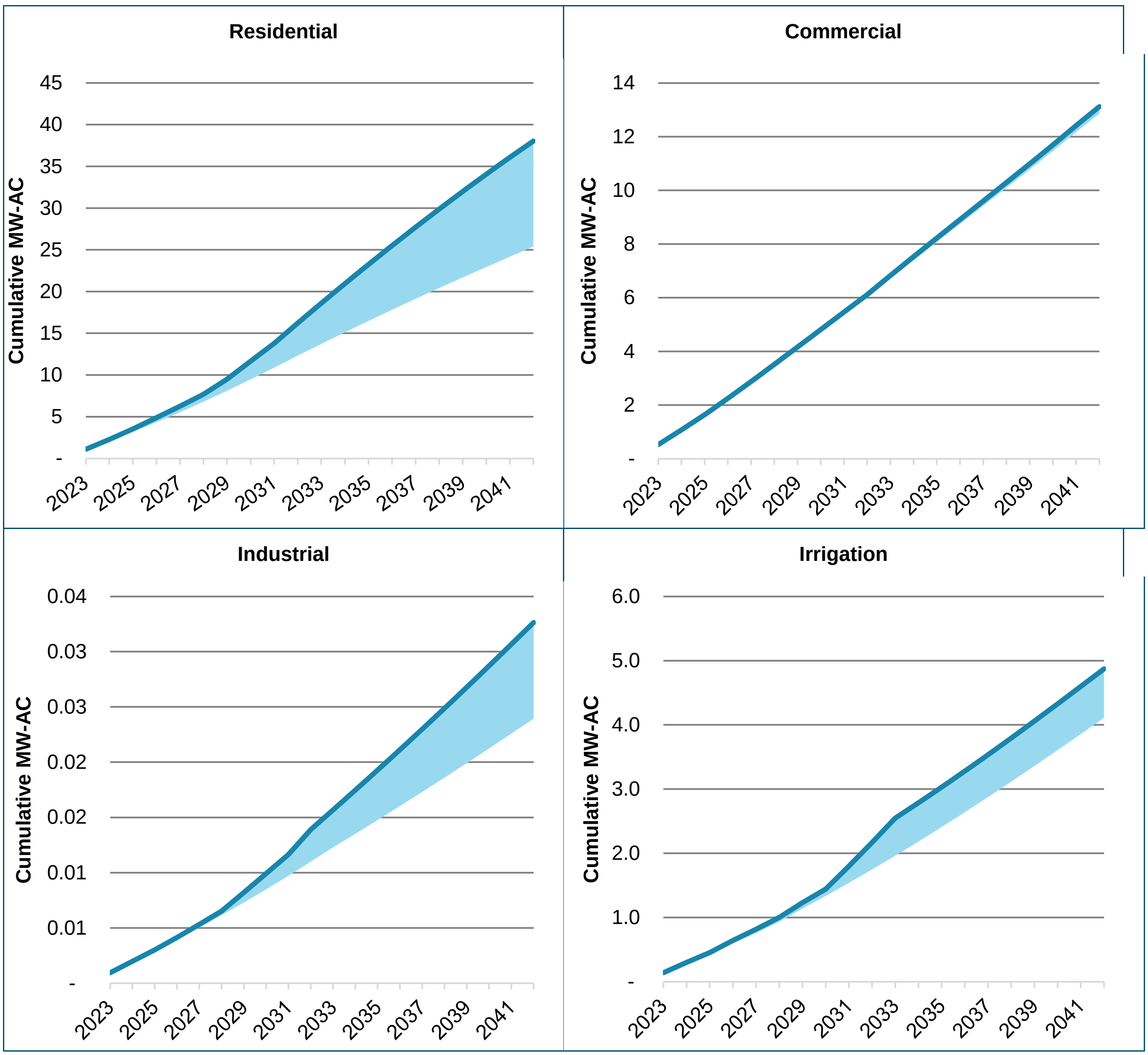


4.1.1.1 California PV Adoption by Sector

The impact of the three different scenarios on PV adoption by sector is shown in the following charts, which present the differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors. In the residential sector, the share of PV + Battery capacity is about 8% of total PV capacity in 2042 for the high case. The share of PV + Battery capacity is about 20% of total commercial PV capacity in 2042 for the high case. The irrigation sector has a similar portion of its PV capacity in PV + Battery configurations, at 14% of total capacity in the high case. The industrial sector did not have any PV + Battery adoption forecasted.

Figure 4-10 Cumulative New PV Capacity Installed by Sector Across All Scenarios, California, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



4.1.2 Idaho

PacifiCorp's customers in Idaho are projected to install about 179 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is about 1% greater than the base case and the low projection is 33% less than the base case, or 181 MW and 121 MW, respectively.

Idaho has a fairly generous incentive program for residential customers that boosted the sector's adoption, compared to the other sectors. The incentives are provided through the Residential Alternative Energy Income Tax Deduction, discussed in section 3.2.5. DNV assumed Idaho would use the same net billing structure for DER compensation as Utah for the study period (2023-2042). The residential sector has the largest share of the private generation capacity, ranging from 54% in the base and high cases to 48% in the low case. The next largest share of the capacity is forecasted in the commercial sector, ranging from 38% in the low case to 34% in the base and high cases.

Figure 4-11 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Idaho, 2023-2042

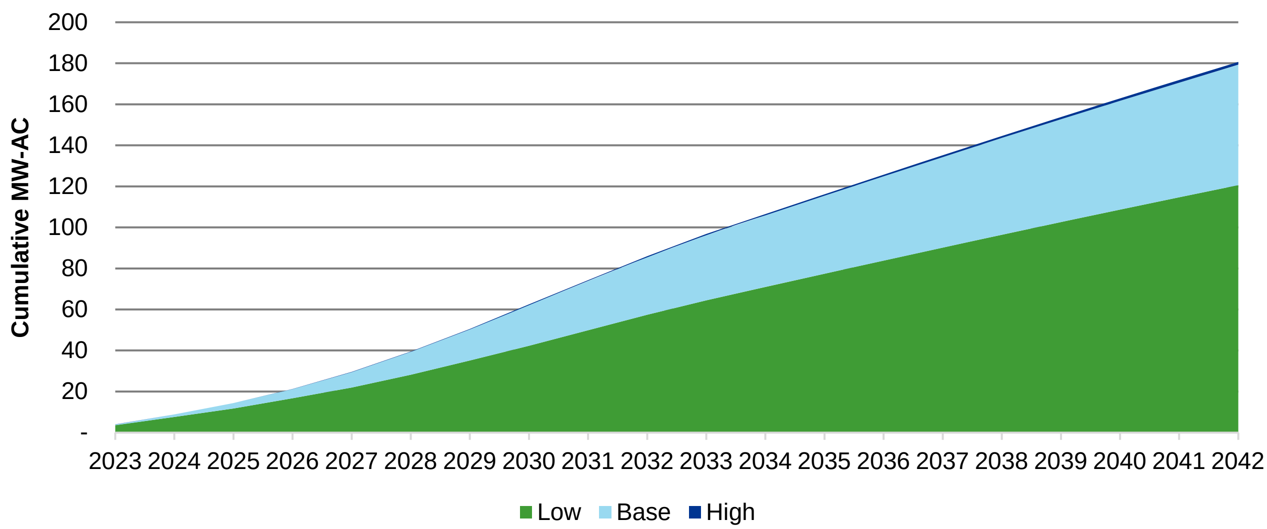


Figure 4-12 Cumulative New Capacity Installed by Technology (MW-AC), Idaho Base Case, 2023-2042

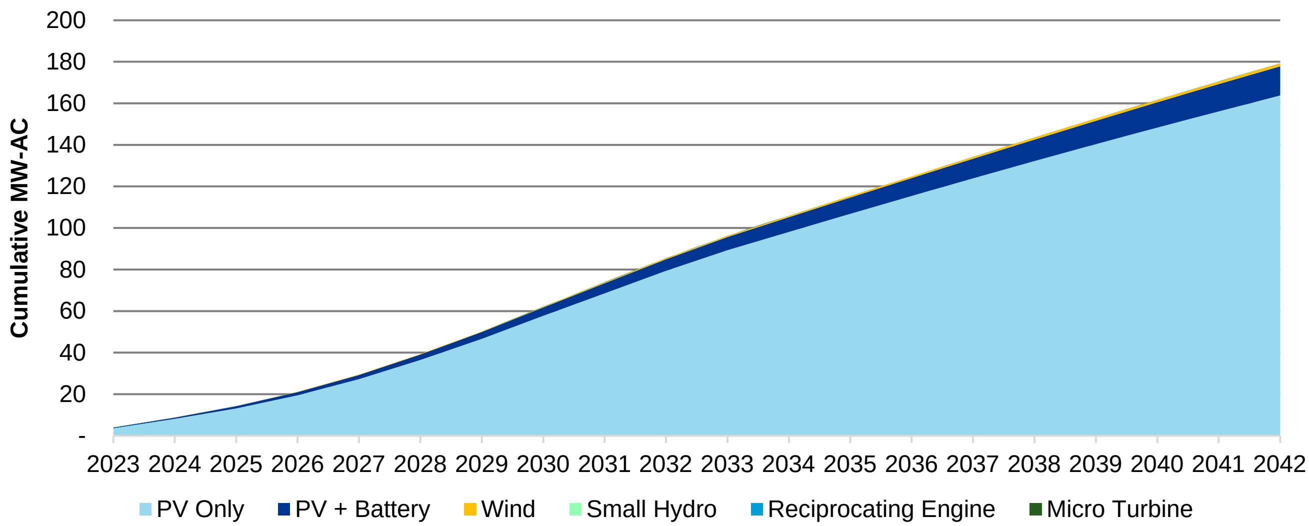


Figure 4-13 Cumulative New Capacity Installed by Technology (MW-AC), Idaho Low Case, 2023-2042

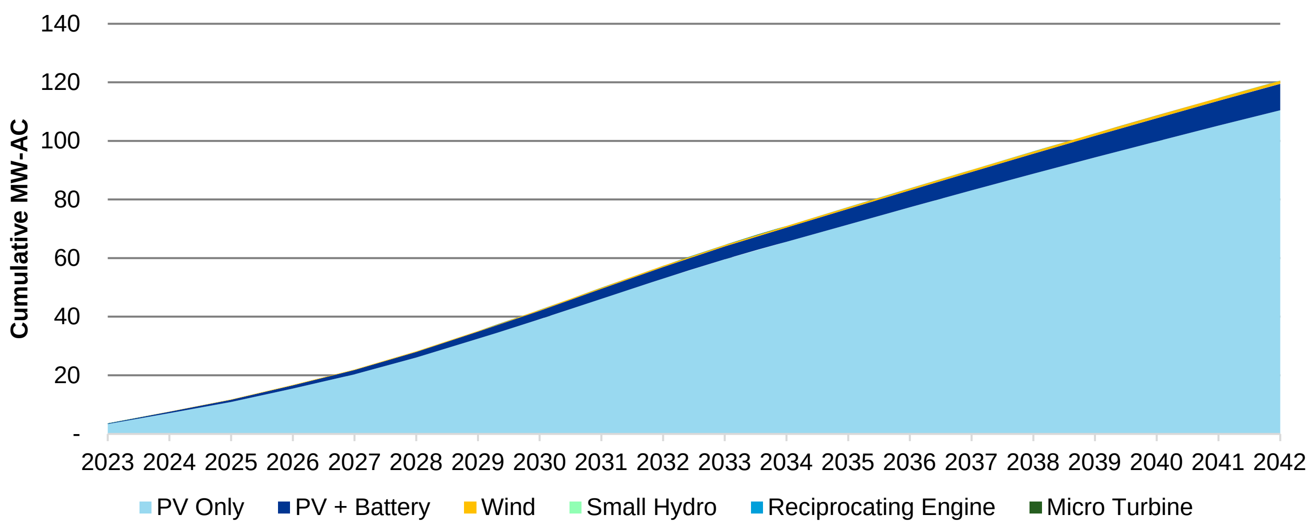
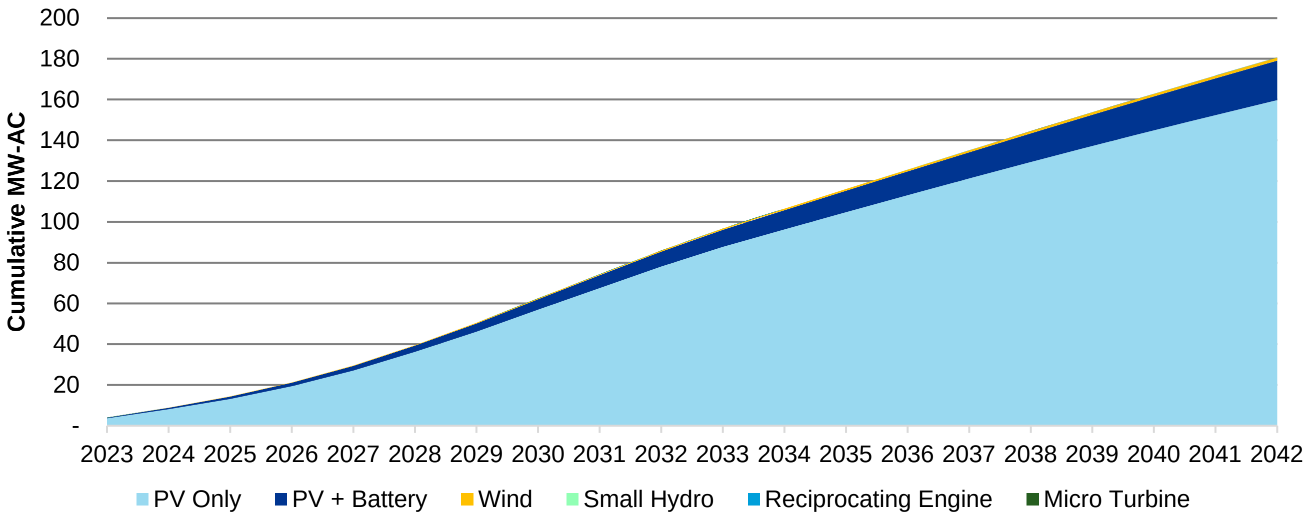


Figure 4-14 Cumulative New Capacity Installed by Technology (MW-AC), Idaho High Case, 2023-2042

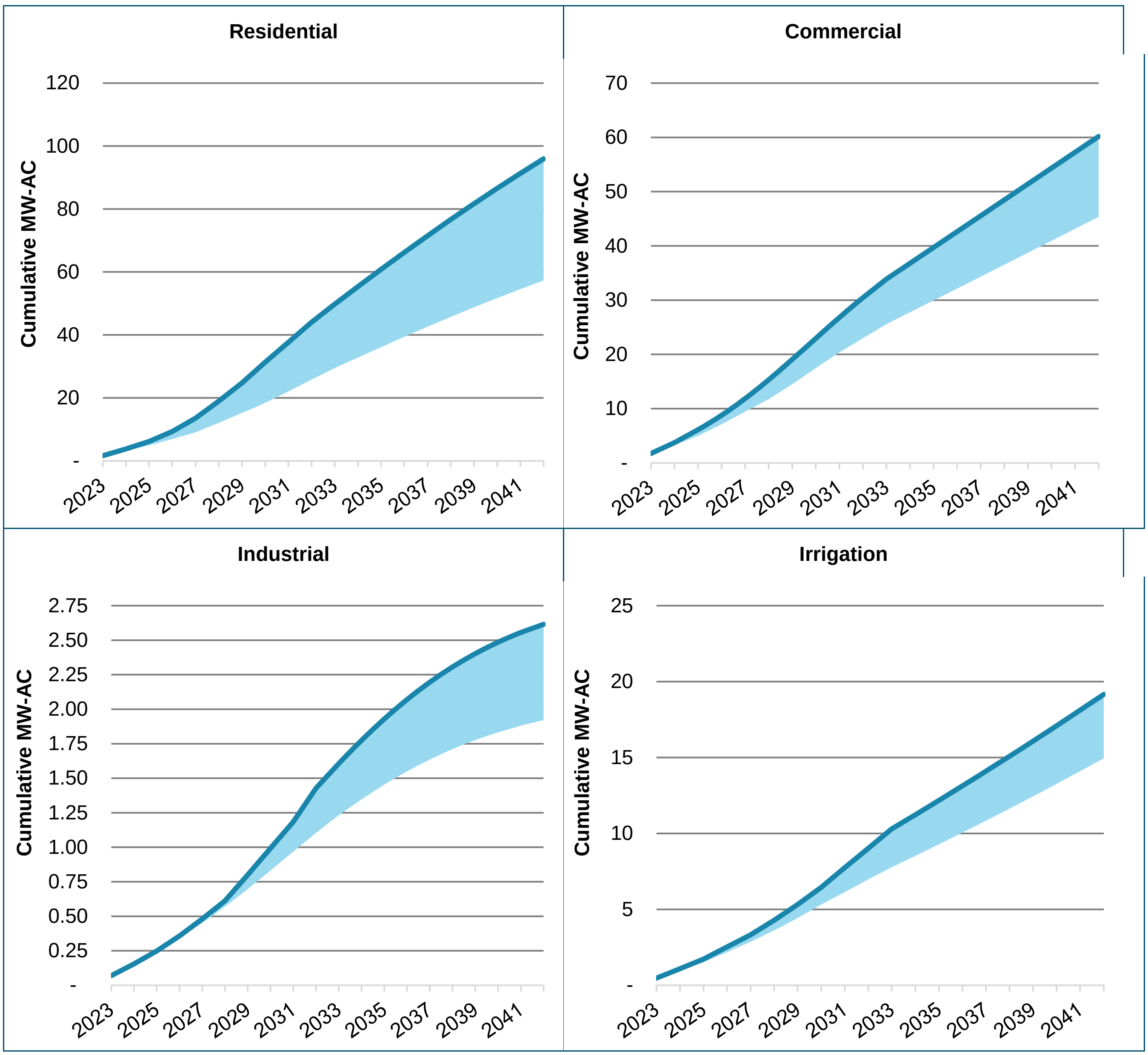


4.1.2.1 Idaho PV Adoption by Sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the high case share of PV + Battery capacity is about 15% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 8% of total commercial PV capacity in 2042. The irrigation sector has a slightly higher portion of its PV capacity in PV + Battery configurations, at 4% of total capacity. The industrial sector did not have any PV + Battery adoption forecasted.

Figure 4-15 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Idaho, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



4.1.3 Oregon

PacifiCorp's customers in Oregon are projected to install about 1,020 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is slightly higher than the base case and the low projection is 39% less than the base case, or 1,022 MW and 623 MW, respectively.

Oregon has incentives available through the Oregon Department of Energy (DOE) for PV + Battery systems and the Energy Trust of Oregon (ETO) for PV Only configurations. The ETO offers incentives for both residential and business customers, while the Oregon DOE provides incentives for residential customers only. Both the Oregon DOE and ETO provide increased incentives for households with low- to moderate-incomes. Oregon is the only state in PacifiCorp's territory, at this time, that provides different incentives for residential customers by income level. As the residential private generation forecast was not segmented by income level, DNV had to develop a single incentive value for the economic analysis. In order to incorporate the higher incentives for the income-qualified customers, DNV developed a weighted average incentive for Oregon residential customers. The income-level weights were calculated from the demographic data of the pool of potential adopters for each technology, in order to best represent the total technology cost (net of incentives) that Oregon residential customers are making their purchasing decisions based off of. Annual household income was included in the census-tract-level demographic data that DNV incorporated into PacifiCorp's Oregon Distribution System Plan circuit-level private generation forecast. While the higher incentive for income-qualified customers provides a boost to customer economics, it does not address the other larger barriers to adoption, such as lack of access to capital and home ownership status. Therefore representation of low- to moderate-income households in the pool of potential adopters for the PV and PV + Battery technologies is still very low.

The PV + Battery incentives offered for residential customers by the Oregon DOE provided a boost to customer economics that led to the majority of PV + Battery adoption growth being in the residential sector. The majority of the PV Only adoption growth in the early years of the forecast is in the commercial sector, with the residential sector following closely behind and eventually overtaking the forecast in the later years. Oregon's net metering policies were assumed to stay in place throughout the study, providing more favorable economics for PV Only—compared to PV + Battery systems.

Figure 4-16 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Oregon, 2023-2042

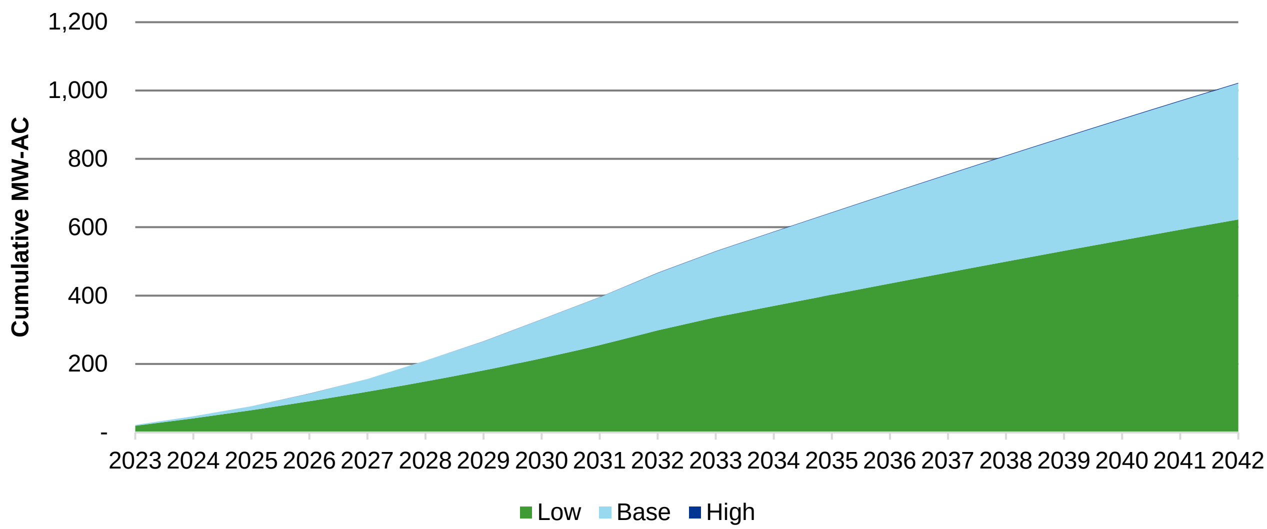


Figure 4-17 Cumulative New Capacity Installed by Technology (MW-AC), Oregon Base Case, 2023-2042

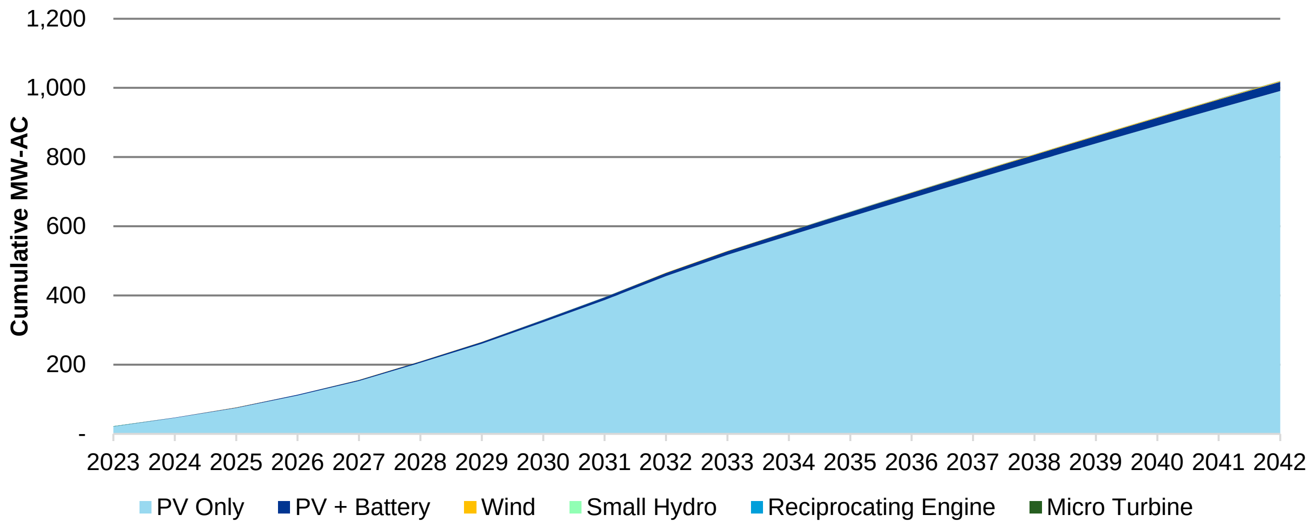


Figure 4-18 Cumulative New Capacity Installed by Technology (MW-AC), Oregon Low Case, 2023-2042

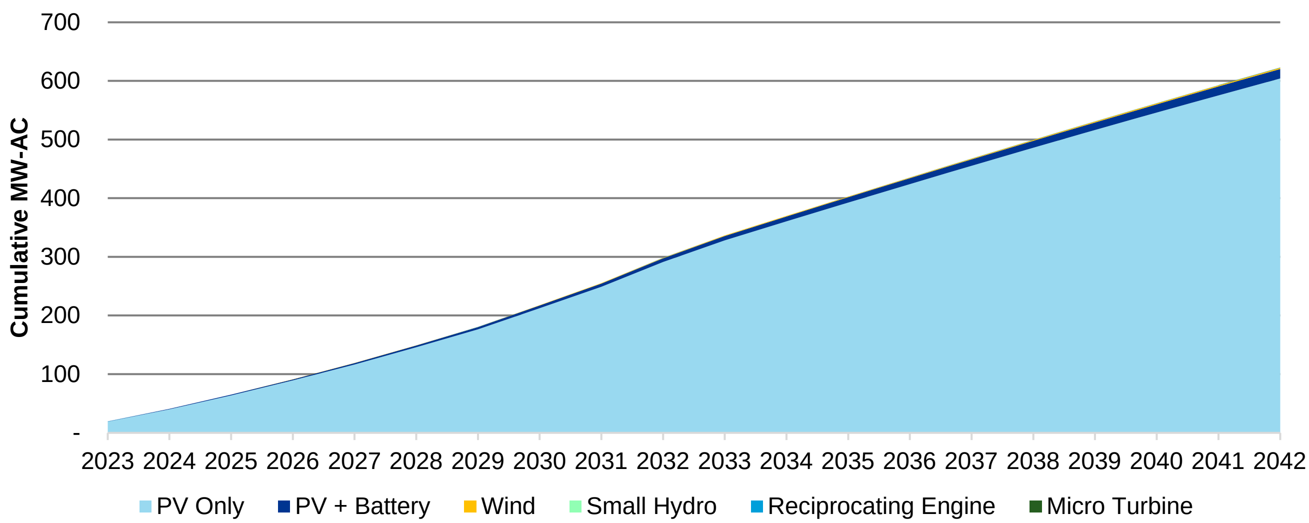
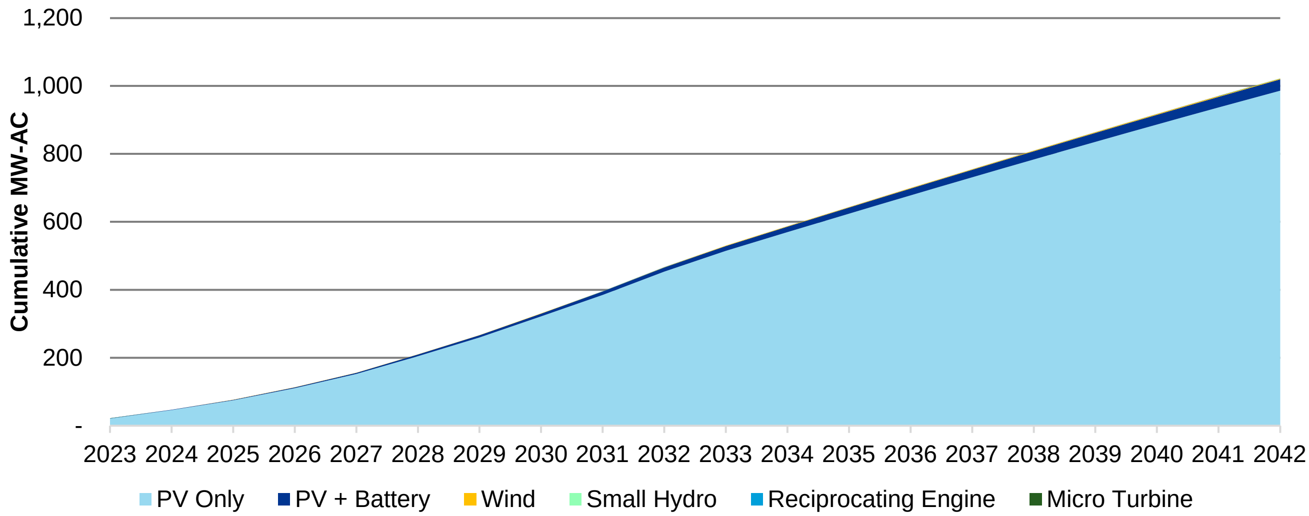


Figure 4-19 Cumulative New Capacity Installed by Technology (MW-AC), Oregon High Case, 2023-2042

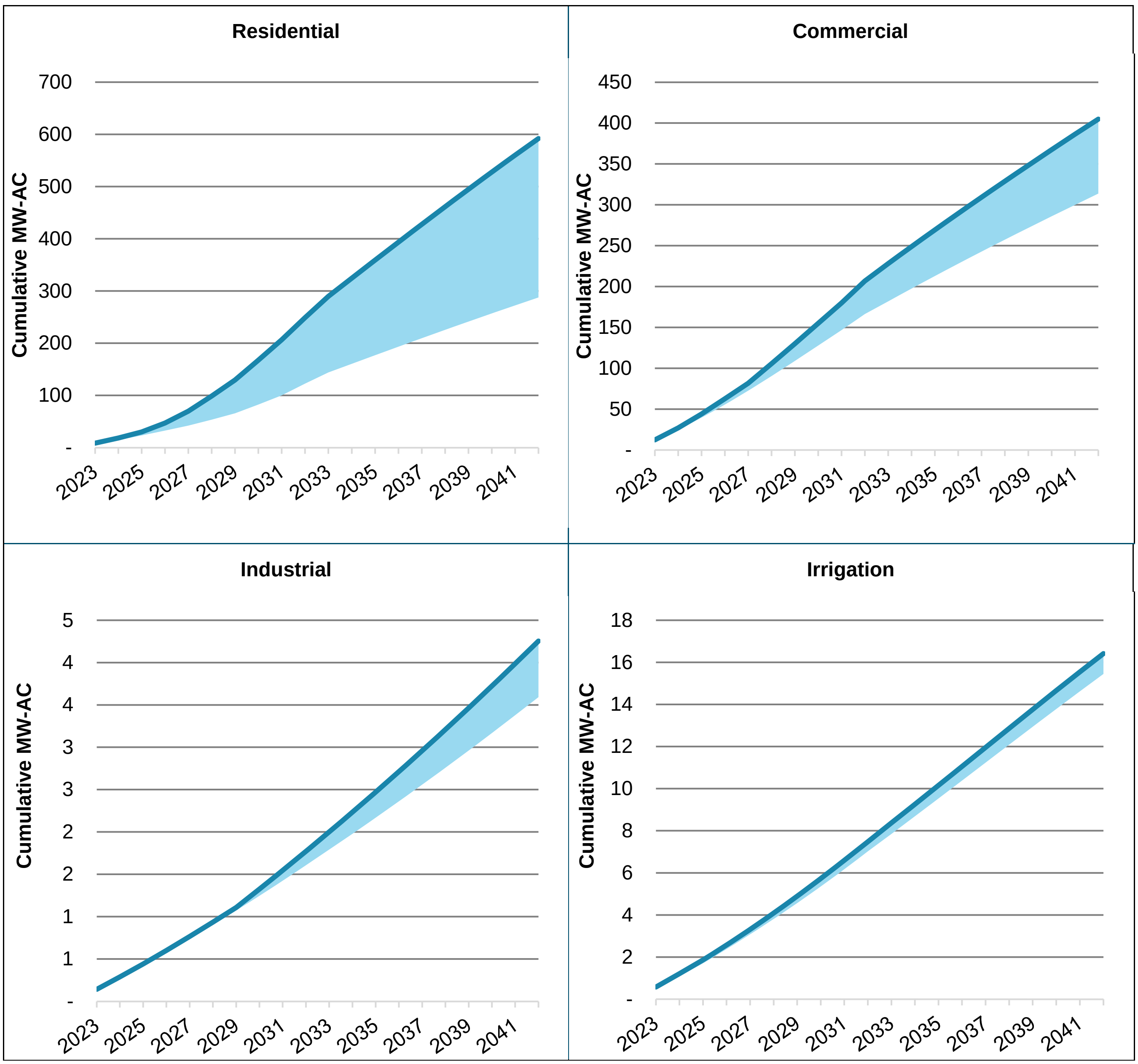


4.1.3.1 Oregon PV Adoption by Sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is about 4% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 2% of total commercial PV capacity in 2042. The irrigation sector has a similar portion of its PV capacity in PV + Battery configurations, at 3% of total capacity. The industrial sector did not have any PV + Battery adoption forecasted.

Figure 4-20 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Oregon, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



4.1.4 Utah

PacifiCorp's customers in Utah are projected to install about 1,733 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is less than 1% greater than the base case and the low projection is 34% less than the base case, or 1,742 MW and 1,140 MW, respectively.

Utah has an incentive program for residential and business customers, but the residential PV incentive expires in 2023. The incentives are provided through through Utah Office of Energy Development Renewable Energy Systems Tax Credit, discussed in section 3.2.5. DNV assumed Utah's net billing policies would remain in place throughout the study. In all cases, the commercial sector has the largest share of the private generation capacity forecasted—ranging from 50% to 58% in the high and low cases, respectively. The residential sector represents the 42% of the capacity forecast in the high and base scenarios, but only 33% in the low case.

Figure 4-21 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Utah, 2023-2042

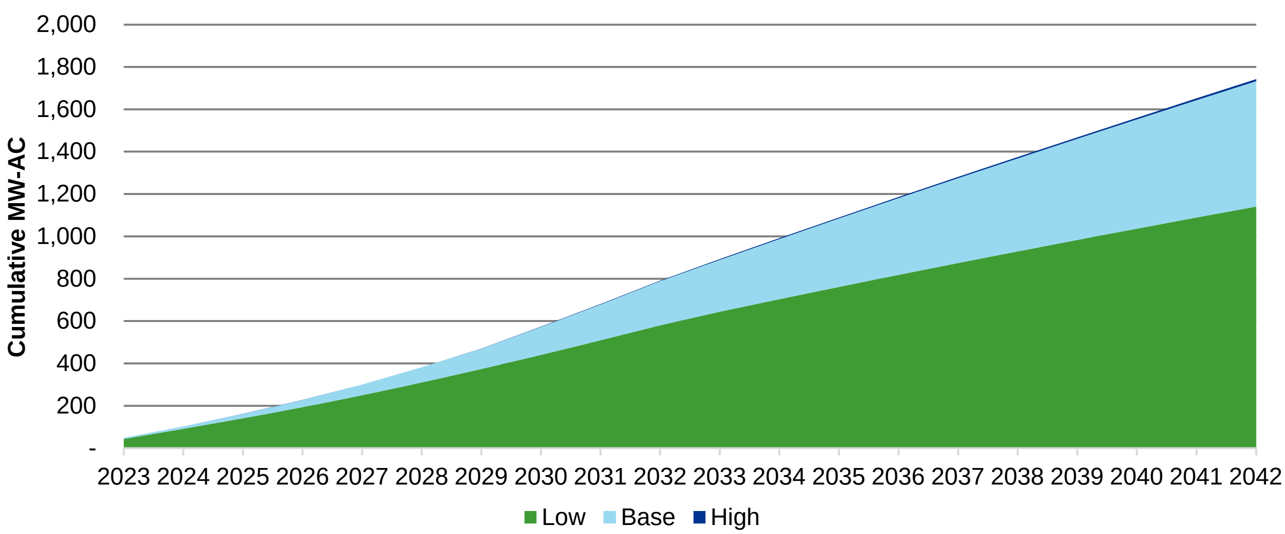


Figure 4-22 Cumulative New Capacity Installed by Technology (MW-AC), Utah Base Case, 2023-2042

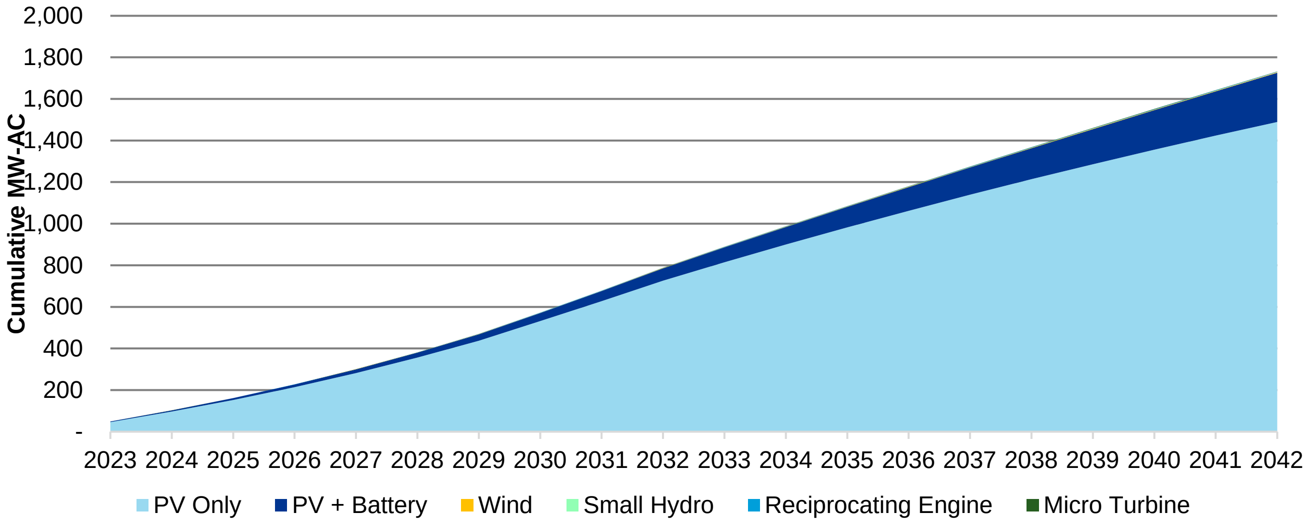


Figure 4-23 Cumulative New Capacity Installed by Technology (MW-AC), Utah Low Case, 2023-2042

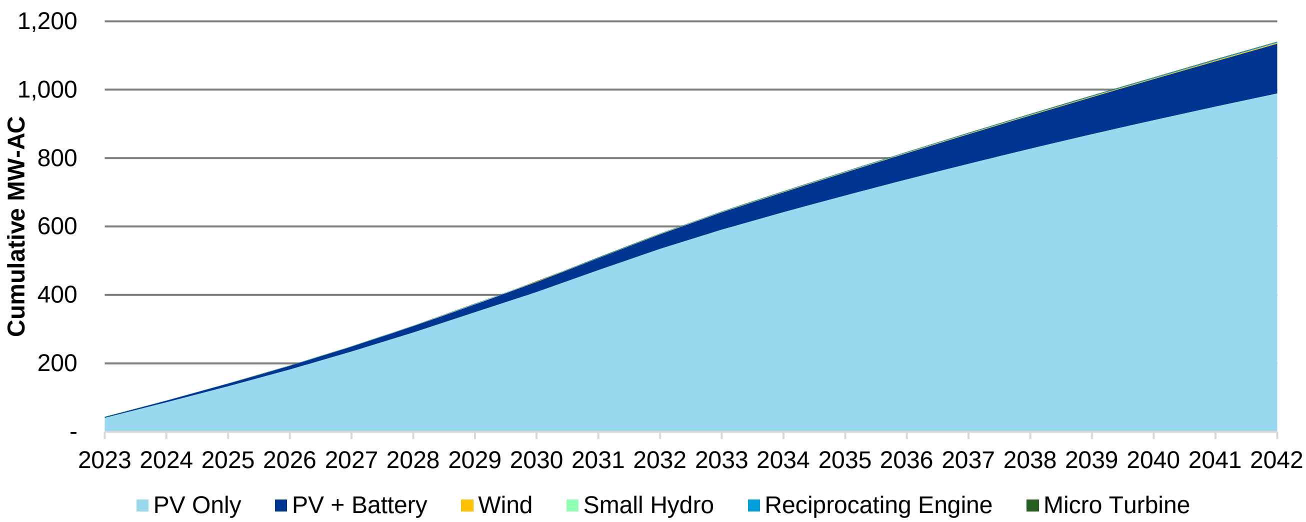
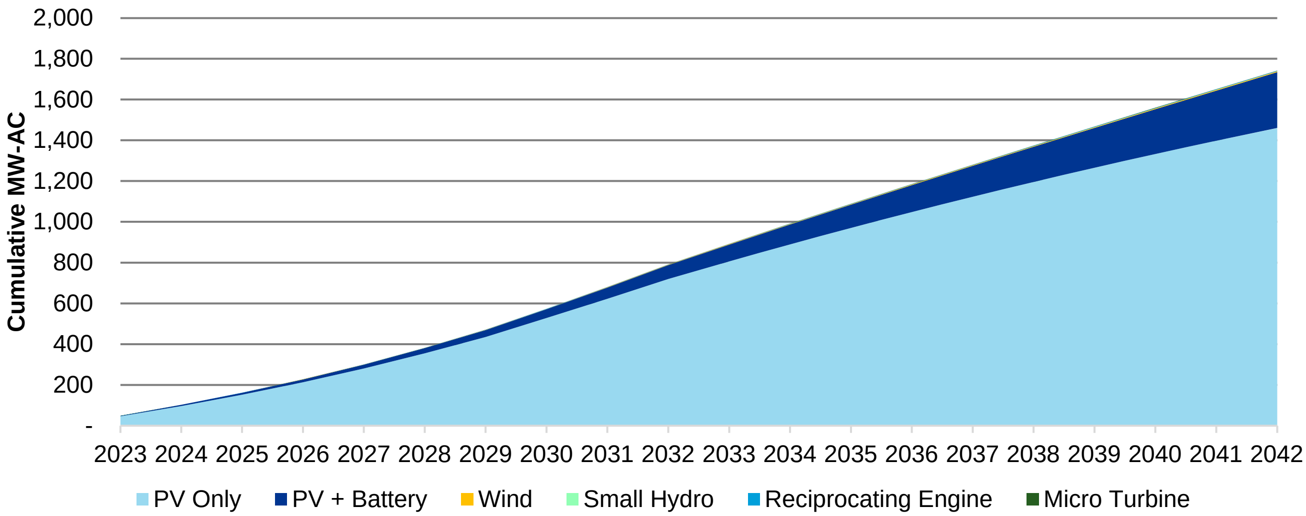


Figure 4-24 Cumulative New Capacity Installed by Technology (MW-AC), Utah High Case, 2023-2042

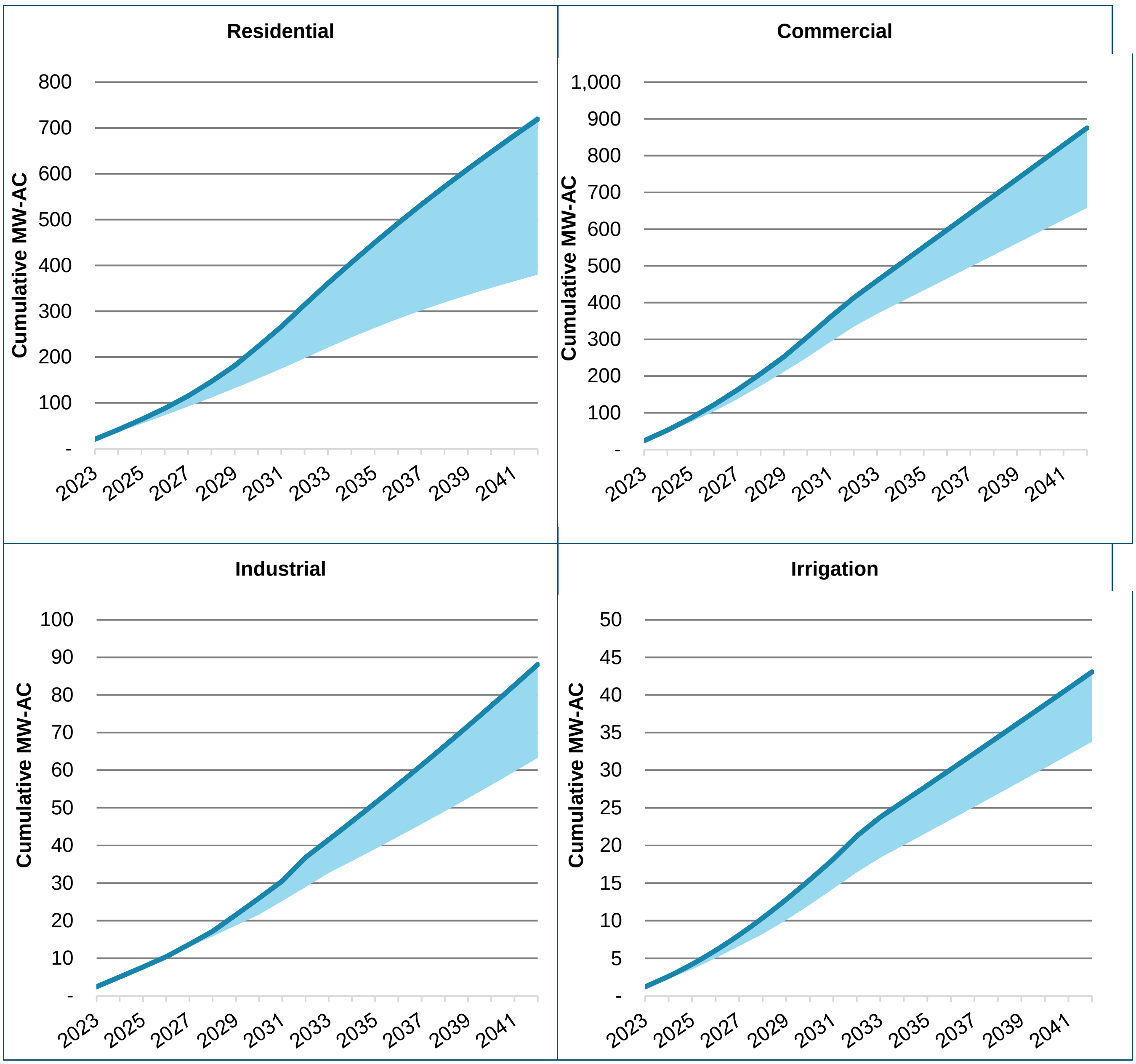


4.1.4.1 Utah PV Adoption by Sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is between 28 and 32% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 4% of total commercial PV capacity in 2042. The industrial sector has a lower portion of its PV capacity in PV + Battery configurations, at 1% of total capacity. About 5% of the irrigation sector PV capacity forecasted in in a PV + Battery configuration.

Figure 4-25 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Utah, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



4.1.5 Washington

PacifiCorp's customers in Washington are projected to install about 140 MW of new private generation capacity over the next two decades in the base case. The 20-year low projection is about 47% less than the base case, or 74 MW. The high case is nearly the same as the base case, seen in Figure 4-26.

Washington state currently offers no incentives for private generation technologies. The residential sector has the largest share of the private generation capacity, ranging from 68% in the base and high cases to 55% in the low case. The next largest share of the capacity is forecasted in the commercial sector, ranging from 41% in the low case to 29% in the base and high cases. Washington's net metering policies were assumed to stay in place throughout the study, providing more favorable economics for PV Only—compared to PV + Battery systems.

Figure 4-26 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Washington, 2023-2042

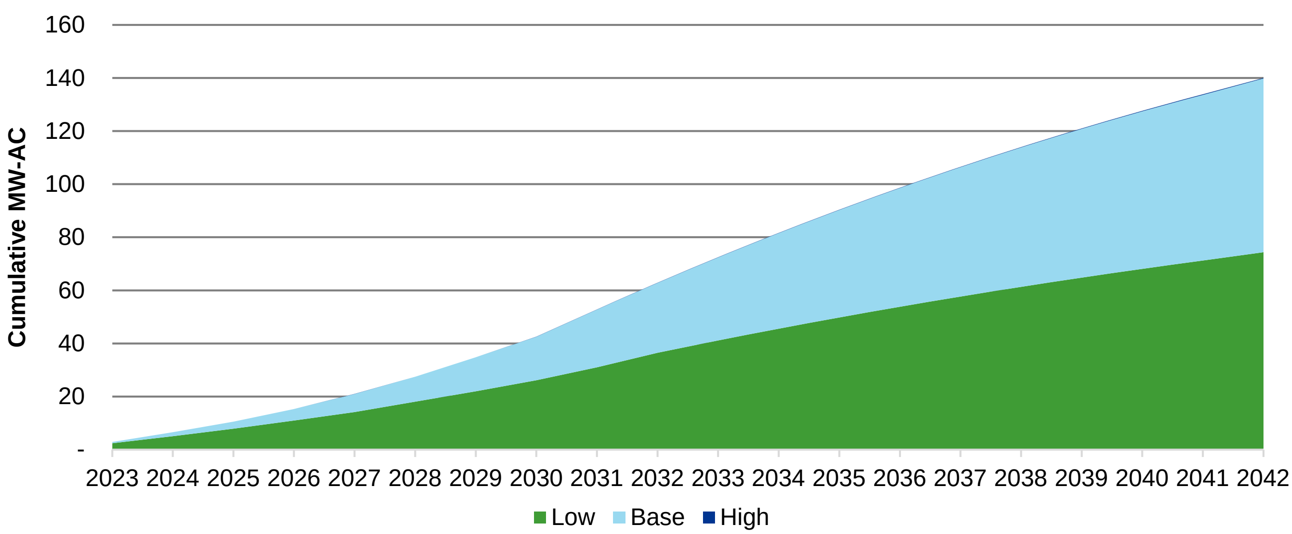


Figure 4-27 Cumulative New Capacity Installed by Technology (MW-AC), Washington Base Case, 2023-2042

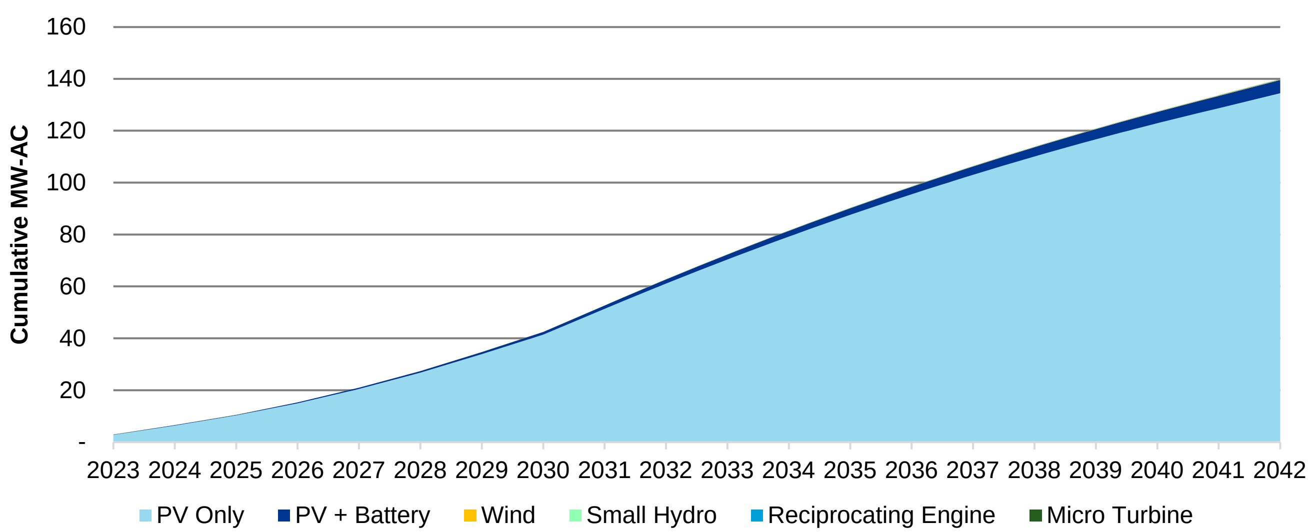


Figure 4-28   Cumulative New Capacity Installed by Technology (MW-AC), Washington Low Case, 2023-2042

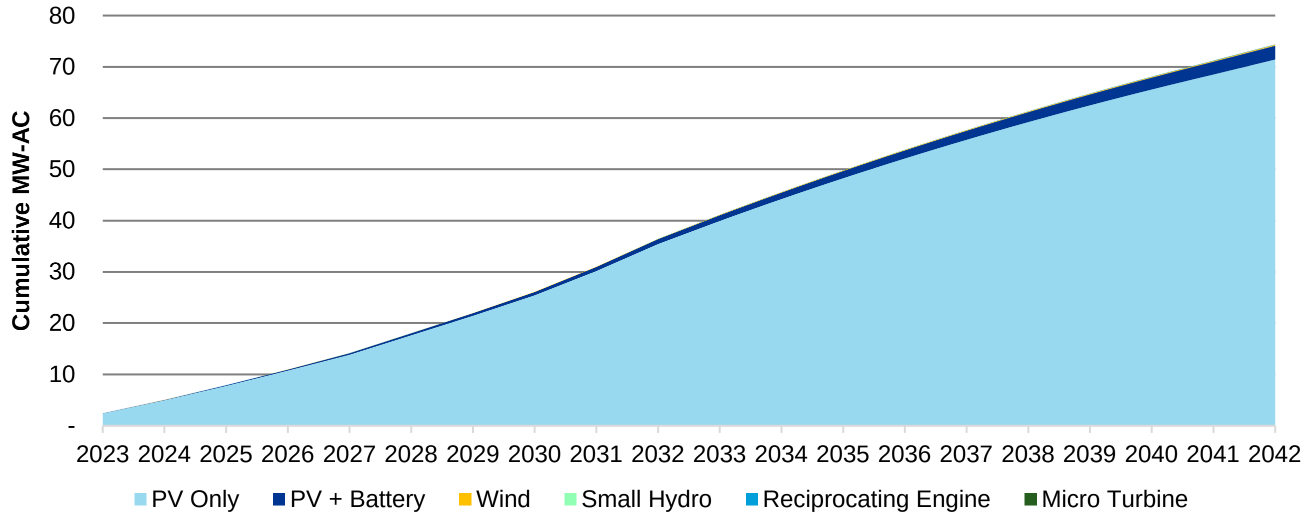
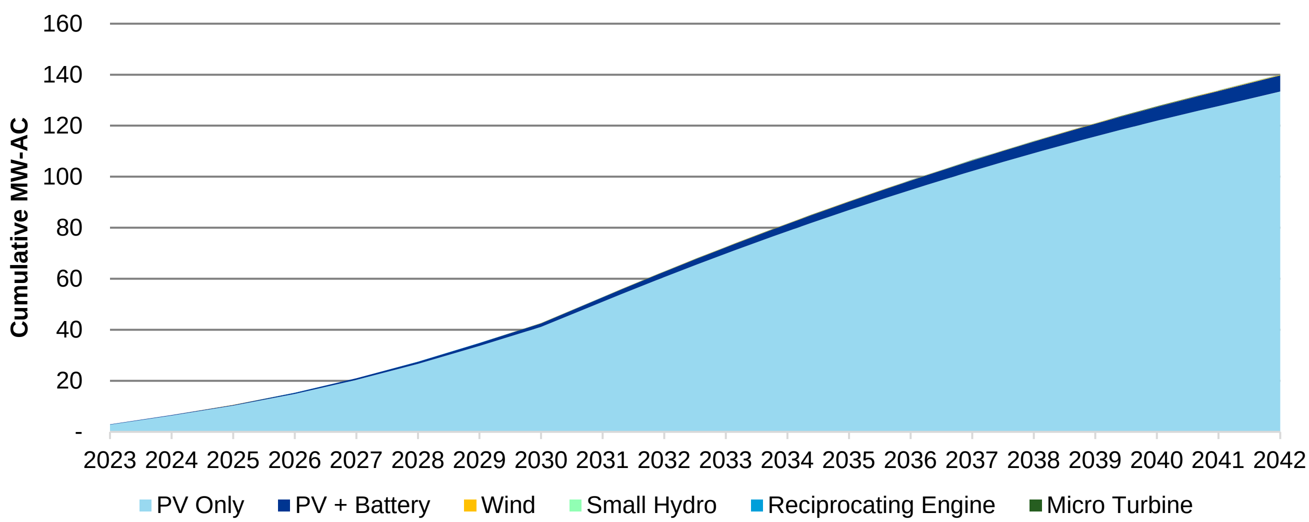


Figure 4-29   Cumulative New Capacity Installed by Technology (MW-AC), Washington High Case, 2023-2042



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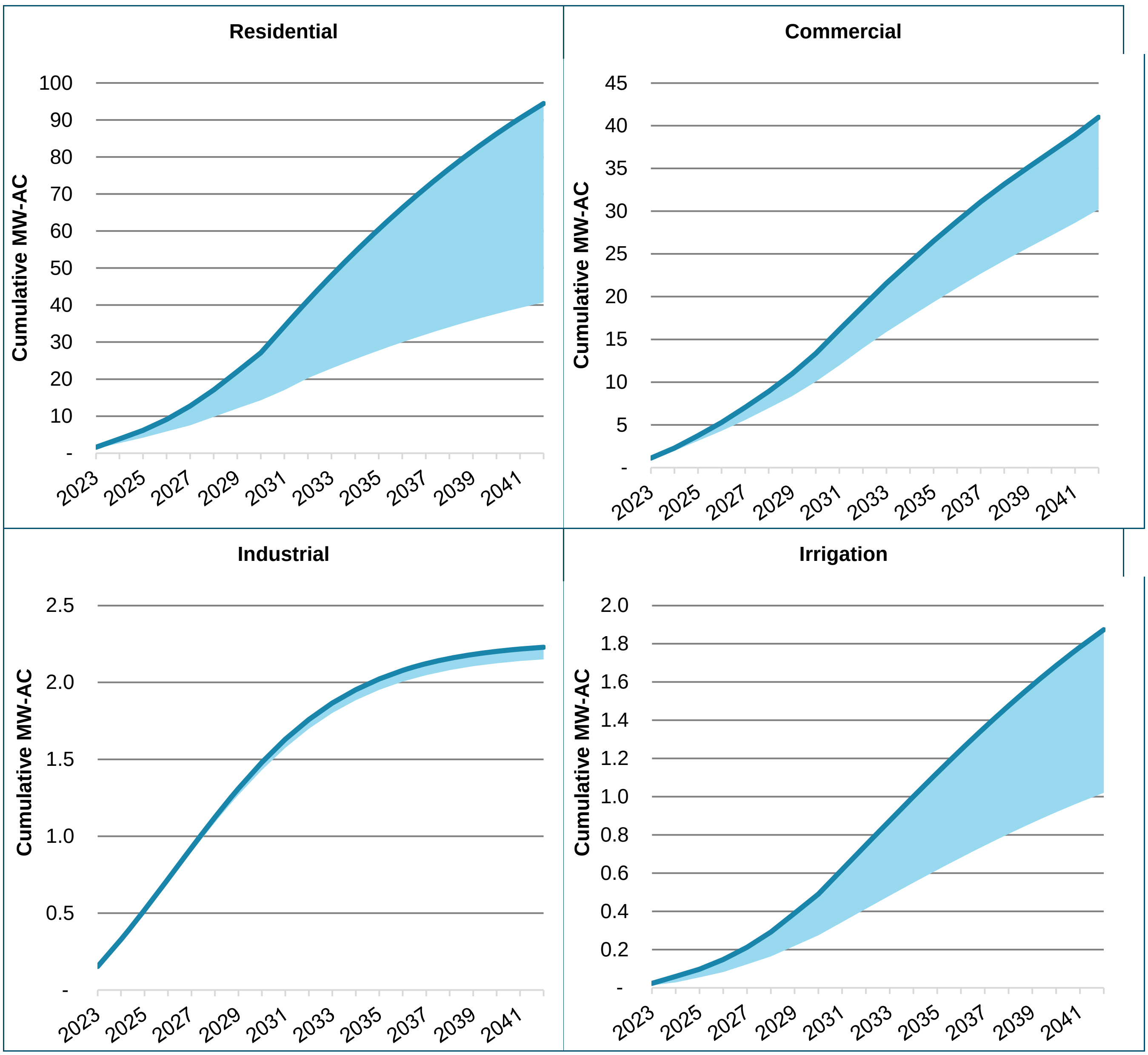
4.1.5.1 Washington PV Adoption by Sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is about 4% of total residential PV capacity in 2042. The share of PV + Battery capacity is about 3% of total commercial PV capacity in 2042. The industrial sector has a higher portion of its PV capacity in PV + Battery configurations, at 8% of total capacity. In the irrigation sector, the share of PV + Battery capacity is between 2% and 4%, depending on the forecast scenario, of total irrigation PV capacity in 2042.

Figure 4-30 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Washington, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



4.1.6 Wyoming

PacifiCorp's customers in Wyoming are projected to install about 51 MW of new private generation capacity over the next two decades in the base case. The 20-year high projection is approximately 2% greater than the base case and the low projection is about 50% less than the base case, or 52 MW and 26 MW, respectively.

Wyoming currently offers no incentives for private generation technologies. The residential sector has the largest share of the private generation capacity, ranging from 64% in the low case to 71% in the high and bae cases. The next largest share of the capacity is forecasted in the commercial sector, ranging from 28% in the high and base cases to 34% in the low case. Wyoming's net metering policies were assumed to stay in place throughout the study, providing more favorable economics for PV Only—compared to PV + Battery systems.

Figure 4-31 Cumulative New Private Generation Capacity Installed by Scenario (MW-AC), Wyoming, 2023-2042

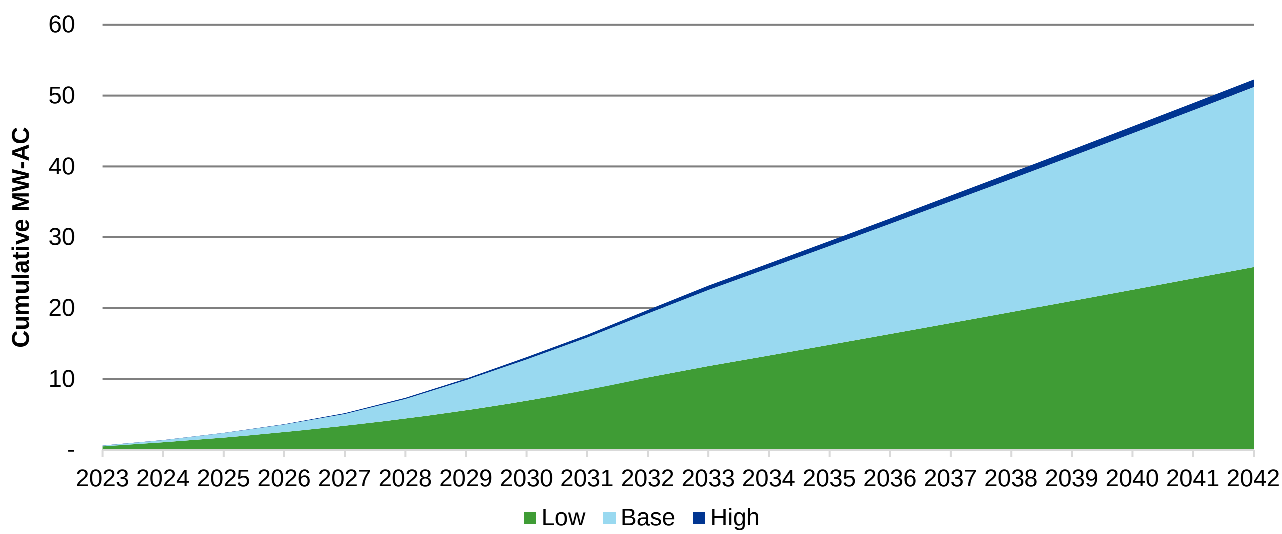


Figure 4-32 Cumulative New Capacity Installed by Technology (MW-AC), Wyoming Base Case, 2023-2042

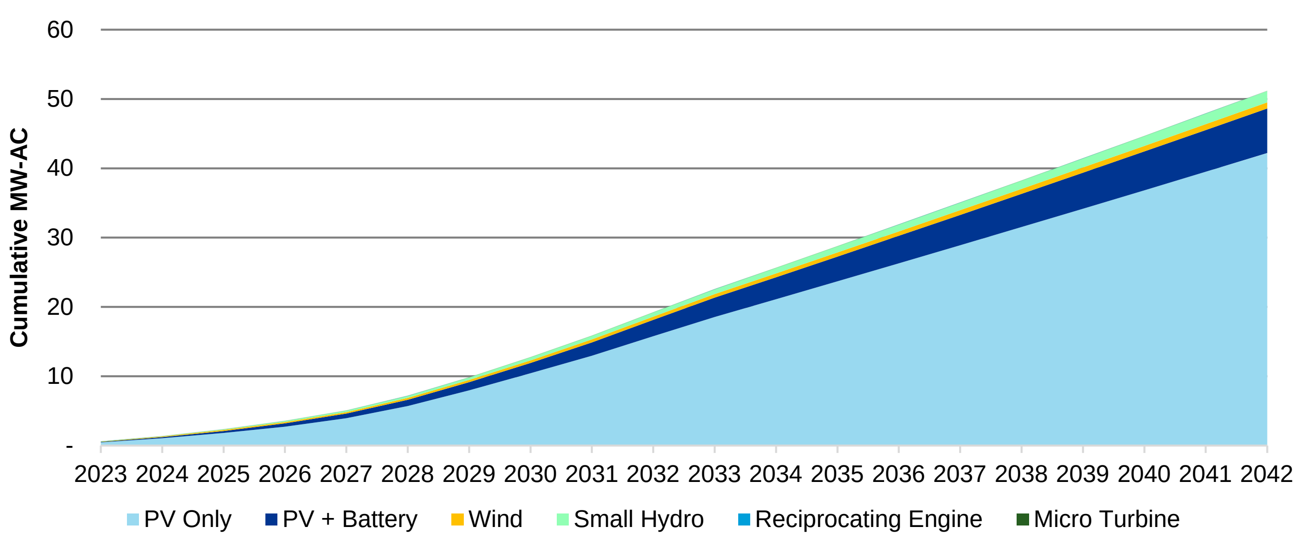


Figure 4-33 Cumulative New Capacity Installed by Technology (MW-AC), Wyoming Low Case, 2023-2042

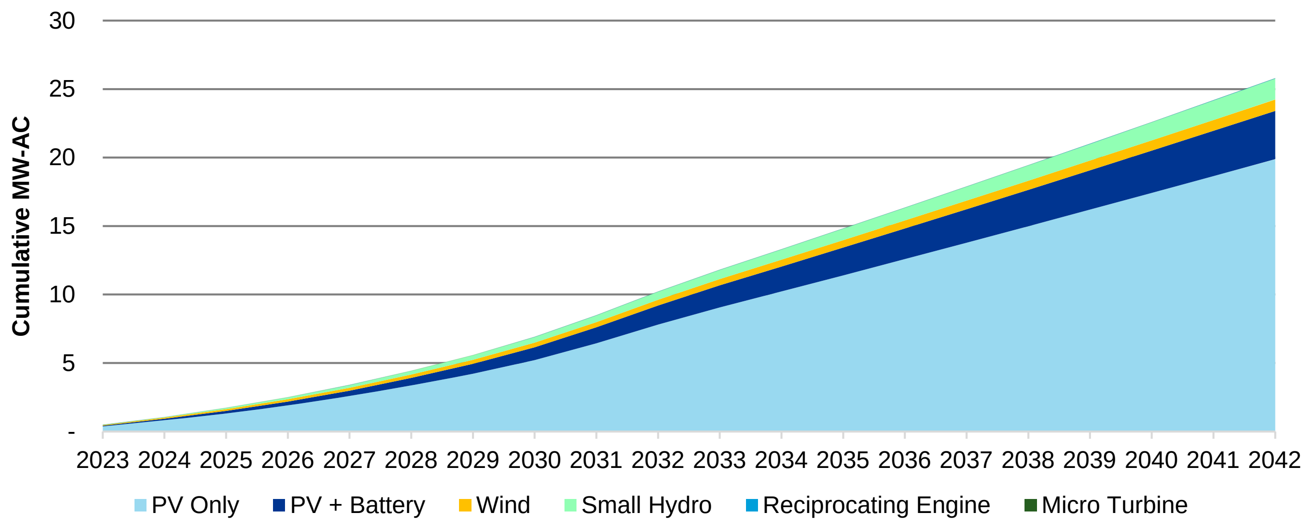
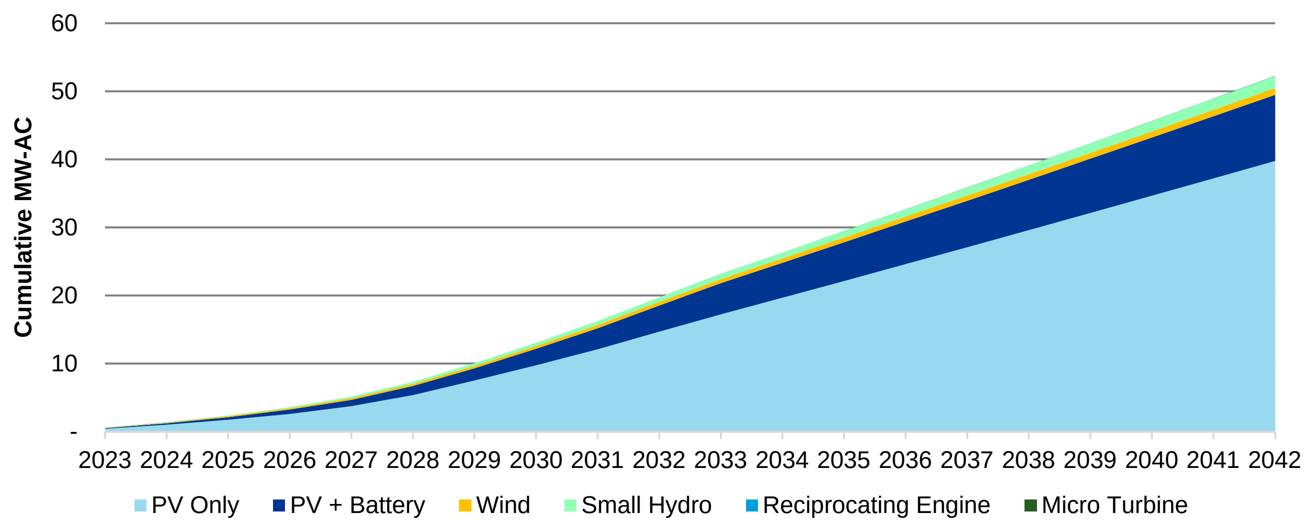


Figure 4-34 Cumulative New Capacity Installed by Technology (MW-AC), Wyoming High Case, 2023-2042

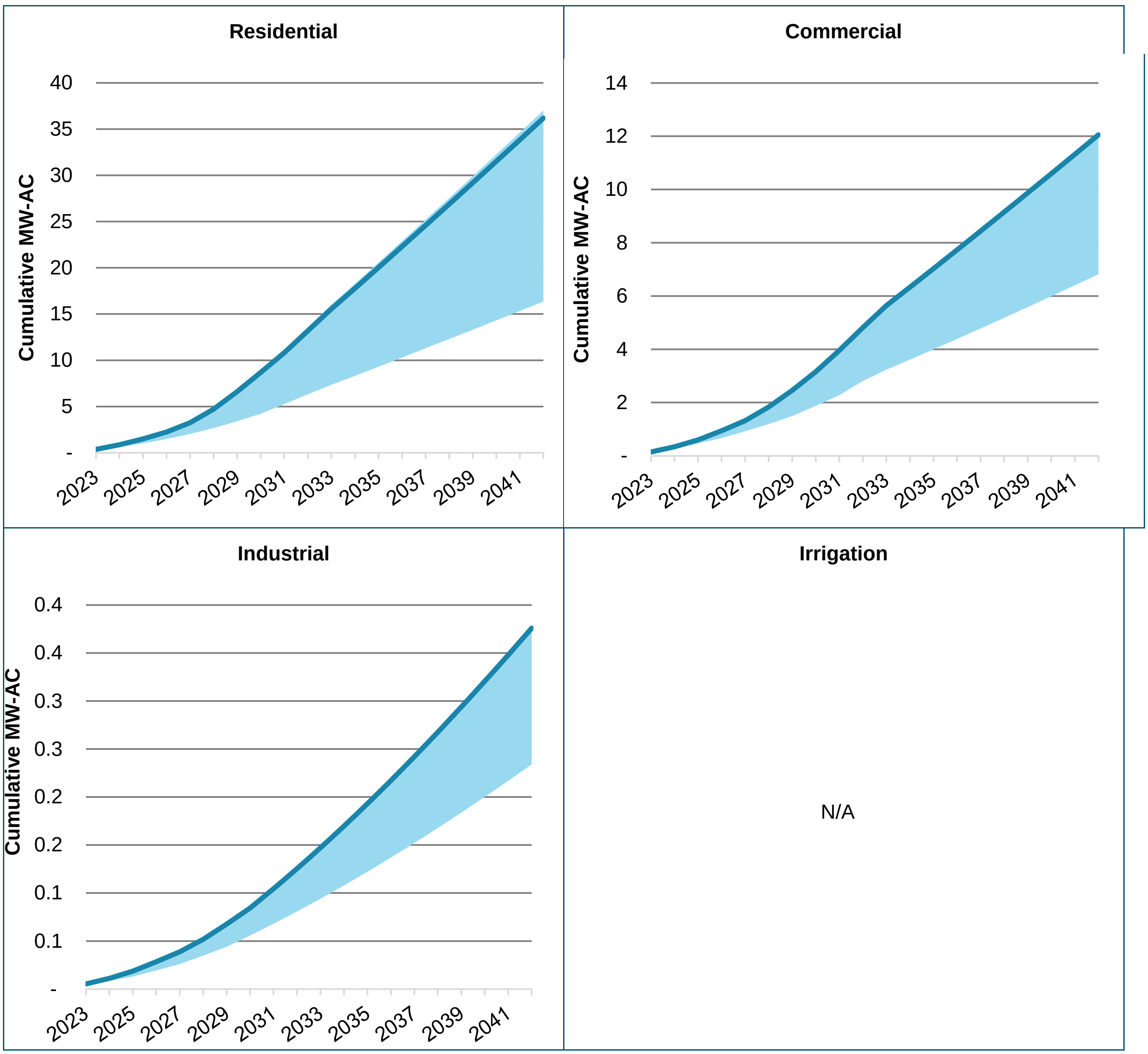


4.1.6.1 Wyoming PV Adoption by Sector

The differences in PV capacity relative to the base case for the three modeled scenarios across the four sectors are presented in the following charts. In the residential sector, the share of PV + Battery capacity is between 19% and 23% of total residential PV capacity in 2042, depending on the forecast scenario. The share of PV + Battery capacity is about 6% of total commercial PV capacity in 2042. The industrial sector has a lower portion of its PV capacity in PV + Battery configurations, at 5% of total capacity. The irrigation sector did not have any PV (PV Only or PV + Battery) adoption forecasted.

Figure 4-35 Cumulative New PV Capacity Installed by Sector Across All Scenarios, Wyoming, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



APPENDIX A TECHNOLOGY ASSUMPTIONS AND INPUTS

Appendix A.xlsx

APPENDIX B DETAILED RESULTS

Appendix B.xlsx

APPENDIX C WASHINGTON COGENERATION LEVELIZED COSTS

Section 480.109.100 of the Washington Administrative Code establishes high-efficiency cogeneration as a form of conservation that electric utilities must assess when identifying cost-effective, reliable, and feasible conservation for the purpose of establishing 10-year forecasts and biennial targets. This appendix provides the levelized cost of energy (LCOE) for the two CHP technologies analyzed in this report for three 10-year periods. LCOE is defined as the present cost of electricity generation for the specified technology over its useful lifetime.

Assumptions for the LCOE analysis of both reciprocating engines and microturbines in Washington state are provided in Table C-1and Table C-2 below, with additional information on the specific source for each metric. Similar to previous studies, the cost of system heat recovery was removed from the total system cost component, resulting in LCOE based only on electric power generation for each system. Where applicable, assumptions are presented nominally ($USD).

Table C-1 Reciprocating Engine LCOE Assumptions

METRIC	EXPECTED USEFUL LIFE (EUL)	INSTALLED COST *(INCLUDES INCENTIVES)*	VARIABLE O&M COST	FUEL COST	WACC
UNITS	Years	$/kW	$/MWh	$/MMBtu	%
2022	20	$2,565	$23	$5.67	6.88%
2030	20	$2,655	$27	$4.34	6.88%
2040	20	$2,721	$32	$6.61	6.88%
SOURCE	EPA Catalog of CHP Technologies (Sep. 2017)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	PacifiCorp Natural Gas Forecast for Washington State	PacifiCorp IRP Assumption

Table C-2 Microturbine Engine LCOE Assumptions

METRIC	EXPECTED USEFUL LIFE (EUL)	INSTALLED COST *(INCLUDES INCENTIVES)*	VARIABLE O&M COST	FUEL COST	WACC
UNITS	Years	$/kW	$/MWh	$/MMBtu	%
2022	25	$3,135	$23	$5.67	6.88%
2030	25	$3,229	$27	$4.34	6.88%
2040	25	$3,294	$32	$6.61	6.88%
SOURCE	EPA Catalog of CHP Technologies (Sep. 2017)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	DOE CHP Technology Fact Sheets (Reciprocating Engines)	PacifiCorp Natural Gas Forecast for Washington State	PacifiCorp IRP Assumption

The results of the CHP LCOE analysis are shown below. The calculated levelized costs for both technologies are similar in each analysis year.

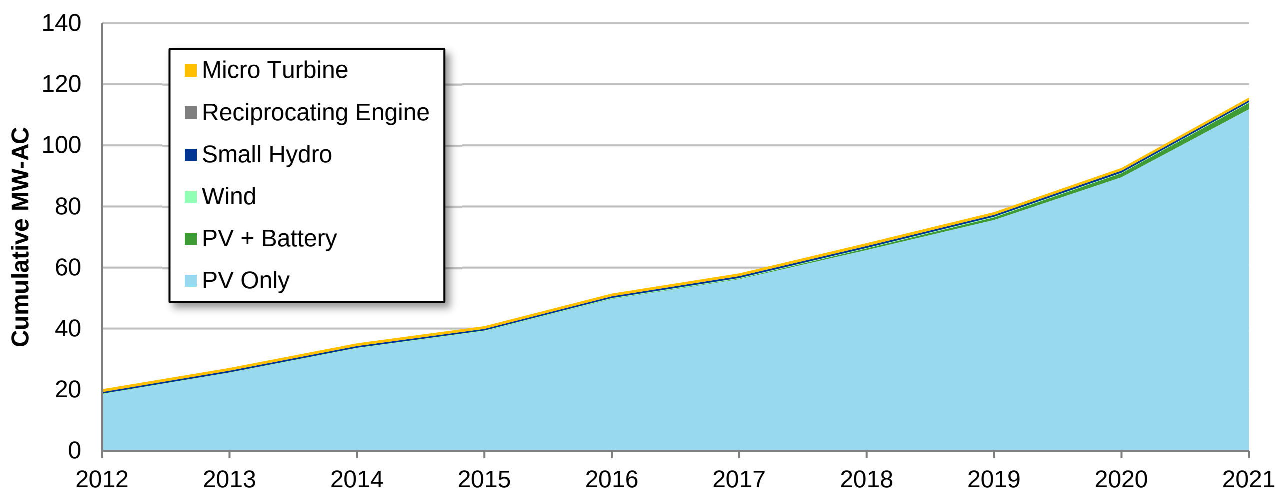
Table C-3 LCOE Results for CHP Systems in Washington State

TECH	RECIPROCATING ENGINES	MICROTURBINES
UNITS	$/MWh	$/MWh
2022	$89.3	$92.8
2030	$99.4	$99.9
2040	$121.4	$116.3

APPENDIX D OREGON DISTRIBUTION SYSTEM PLAN RESULTS

DNV prepared the Long-Term Private Generation (PG) Resource Assessment for PacifiCorp's Oregon distributed energy resource (DER) adoption forecast at the circuit level to support PacifiCorp's 2023 Oregon Distribution System Plan (DSP). This study evaluated the expected adoption of behind-the-meter DERs including photovoltaic solar (PV only), photovoltaic solar coupled with battery storage (PV + Battery), wind, small hydro, reciprocating engines and microturbines for a 20-year forecast horizon (2023-2042). The adoption model DNV developed for this study is calibrated to the current[20] market penetration of these technologies, shown in Figure D-1**.**

Figure D-1 Historic Cumulative Installed PG Capacity by Technology, PacifiCorp, Oregon, 2012-2021



To date, about 99 percent of existing private generation capacity installed in PacifiCorp's Oregon service territory is PV or PV + Battery. To inform the adoption forecast process, the Company conducted an in-depth review of the other technologies and did not find any literature to suggest that they would take on a larger share of the private generation market in Oregon in the future years of this study.

For each technology and sector, PacifiCorp developed three scenarios: a base case, a high case and a low case. The base case is considered the most likely projection as it is based on current market trends and expected changes in costs and retail rates; the high and low cases are used as sensitivities to test how changes in technology costs and retail rates impact customer adoption of these technologies. These scenarios use technology cost and performance assumptions specific to PacifiCorp's Oregon service territory in the base year of the study. The base case assumes the current federal income tax credit schedules and state incentives, retail electricity rate escalation from the AEO[21] reference case, and a blended version of the NREL Annual Technology Baseline[22] moderate and conservative technology cost forecasts. In the high case, retail rates increase more rapidly, and technology costs decline at a faster rate compared to the base case to incentivize greater adoption of PG. For the low case, retail rates increase at a slower rate than the base case and technology costs decrease at a slower rate.

[20] PacifiCorp private generation interconnection data as of February 2022.

[21] U.S. Energy Information Administration, Annual Energy Outlook 2022 (AEO2022), (Washington, DC, March 2022).

[22] NREL (National Renewable Energy Laboratory). 2021. 2021 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory.

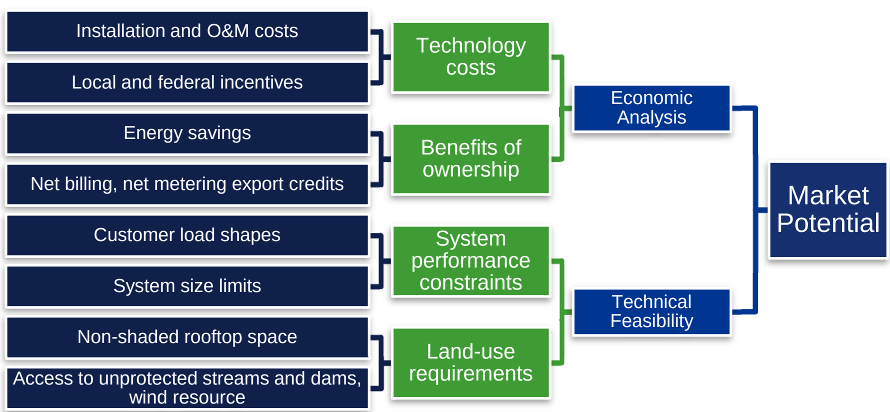
D.1 Study Methodologies and Approaches

The forecasting methodologies and techniques applied by PacifiCorp in this analysis are commonly used in small-scale, behind-the-meter energy resource and energy efficiency forecasting. To forecast private generation adoption at the circuit-level, the Company first developed an adoption model to estimate total PG potential for PacifiCorp's Oregon service territory and then disaggregated these results to develop PG potential estimates for each circuit. The methods used to develop the territory and circuit level results are described in more detail below.

D.1.1 State-Level Forecast Approach

DNV developed a behind-the-meter net economic perspective that includes the acquisition and installation costs for each technology and incorporates the available incentives and economic benefits of ownership as offsets which assumed that the current net metering policies for Oregon remained in place throughout the study horizon. The economic analysis calculated payback by year for each technology by sector. A corresponding technical feasibility analysis determined the maximum, feasible, adoption for each technology by sector. The results of the technical and economic analyses were then used to inform the market adoption analysis. The methodology and major inputs to the analysis are shown in Figure D-2. Changes to technology costs, retail rates, and federal tax credits used in the high and low cases impact the economic portion of the analysis.

Figure D-2 Methodology to Determine Market Potential of Private Generation Adoption



PacifiCorp used technology and sector-specific Bass diffusion curves to model market adoption and derive total market potential. Bass diffusion curves are widely used for forecasting technology adoption. Diffusion curves typically take the form of an S-curve with an initial period of slow early adoption, adoption increasing as the technology becomes more mainstream, and eventually a tapering off among late adopters. The upper limit of the curve is set to maximum market potential, or the maximum share of the market that will adopt the technology regardless of the interventions applied to influence adoption. In this analysis, the long-term maximum level of market adoption was based on payback. As payback was calculated by year in the economic analysis to capture the changing effects of market interventions over time, the maximum level of market adoption in the diffusion curves vary by year in the study.

The model is characterized by three parameters—an innovation coefficient, an imitation coefficient, and the ultimate market potential. The last of these we set equal to the payback-based maximum level of adoption. Together, these three parameters also determine the time to reach maximum adoption and overall shape of the curve. The innovation and imitation parameters were calibrated for each technology and sector, based on current market penetration and when PacifiCorp started to see the technology being adopted in the Company's Oregon service territory.

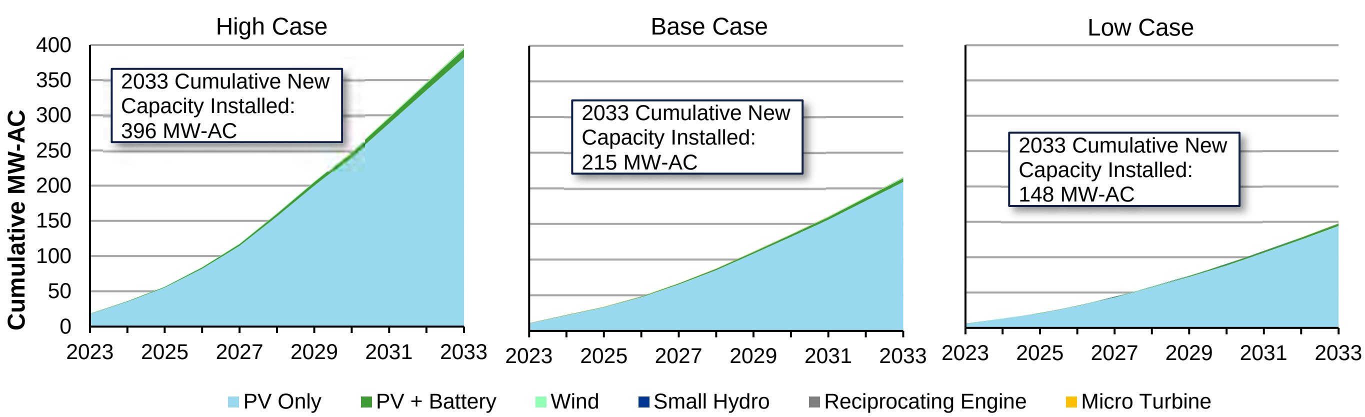
D.1.2 Circuit-Level Forecasting Approach

PacifiCorp conducted a bottom-up approach to develop circuit-level adoption models for each sector and technology. The approach chosen for developing circuit-level forecasts was to disaggregate the state-level forecast described in the previous section. This was due to the use of adoption drivers from data at varying levels of geographic granularity. The circuit-level adoption models incorporated county-level private generation installation data and resource availability by technology[23], census-tract-level demographic data[24] and circuit-level reliability data. The Company used circuit-level customer counts by sector to further segment the localized adoption models by sector and technology. The Company ultimately used a bottom-up approach to develop circuit-level adoption models for each circuit, but due to the above data gaps, their purpose was only to develop factors to allocate the state-wide analysis to each circuit.

D.2 Private Generation Forecast Results

Figure D-3 compares the new service territory-level private generation capacity, in cumulative MW-AC by 2033, projected for each scenario evaluated. The capacity forecasted is incremental to what is already installed in PacifiCorp's Oregon service territory, shown in Figure D-1.

Figure D-3 Private Generation Forecast by Technology, PacifiCorp Oregon, All Cases



Similar to the trends observed in current installed capacity, solar PV[25] makes up 99% of the new PG capacity forecast throughout the study period in all cases. By 2033, the cumulative new PV Only capacity in the base case is 209 MW and PV + Battery capacity is 5 MW. Compared to the base case, the low case forecasts 31% less PV Only capacity, and about 40% percent less PV + Battery capacity. The PV Only cumulative new capacity in the high case in 2033 is 83% greater than the base case. In the high case, 2033 PV + Battery cumulative new capacity is forecasted to be more than double the base case, at 11 MW.

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[23] Conditions suitable for wind and hydro vary widely by region, and the economics of solar adoption is affected by local weather patterns.

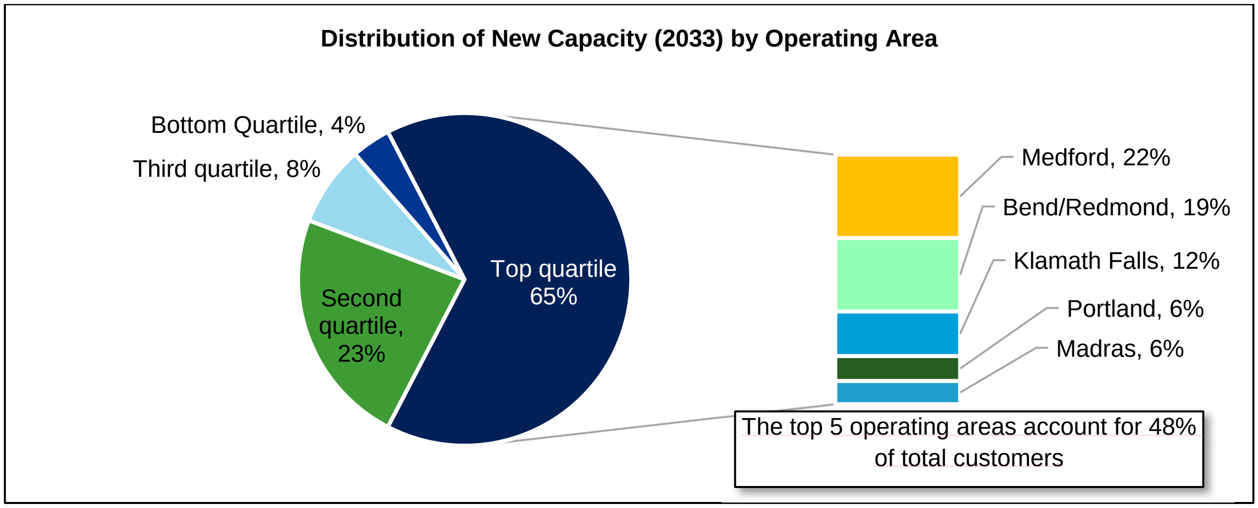
[24] Data including household income, education-level, and home ownership.

[25] The term solar PV, here, is inclusive of PV Only and PV + Battery systems.

D.2.1 Circuit-Level and Substation-Level Results Findings

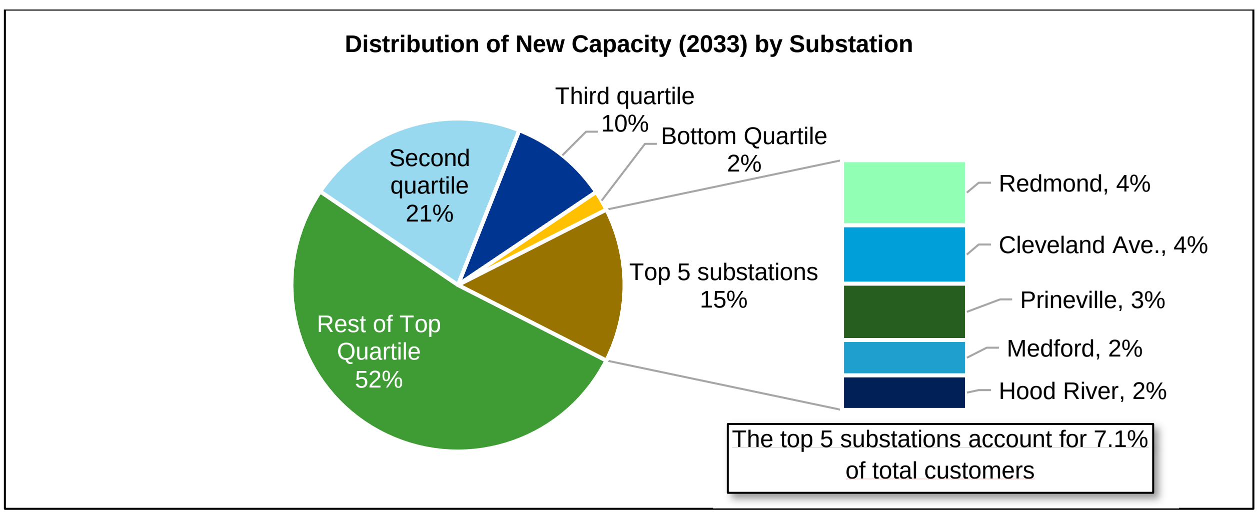
The charts in Figure D-4, Figure D-5, and Figure D-6 show the distribution of new capacity in 2033 by operating area, substation, and circuit within the base case private generation forecast.

Figure D-4 Private Generation Forecast Disaggregation by Operating Area, PacifiCorp Oregon, Base Case



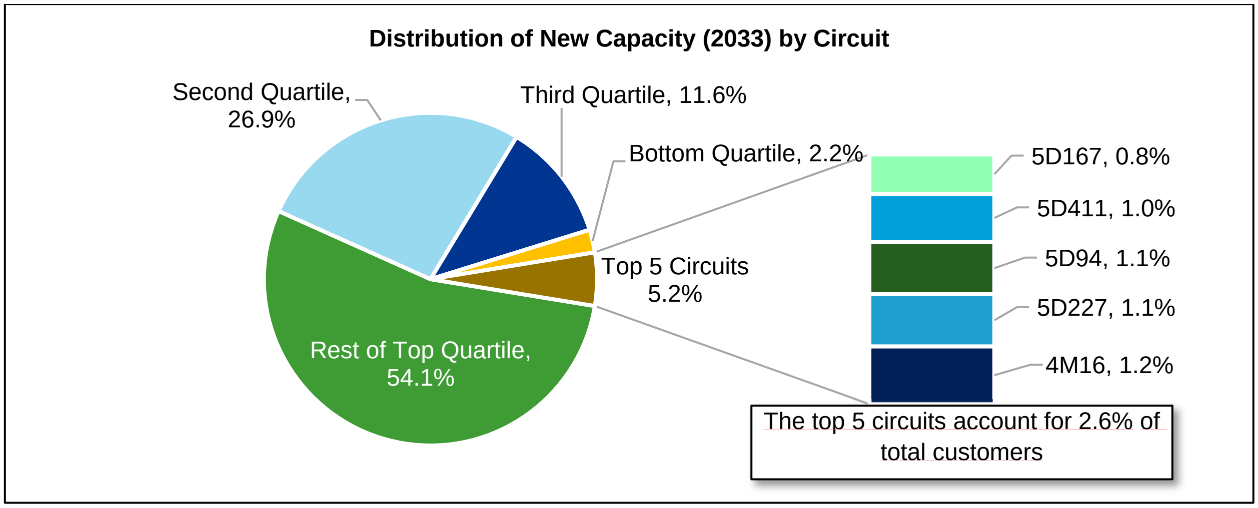
The top five (ranked by new capacity) of PacifiCorp's 22 Oregon operating areas account for 65% of the total forecast capacity in 2033 while only accounting for 48% of total customers.

Figure D-5 Private Generation Forecast Disaggregation by Substation, PacifiCorp Oregon, Base Case



The top five of PacifiCorp's 193 substations account for 15% of 2033 forecast capacity (compared to 7% of customers), with the entire top quartile (representing 49% of customers) accounting for 67%.

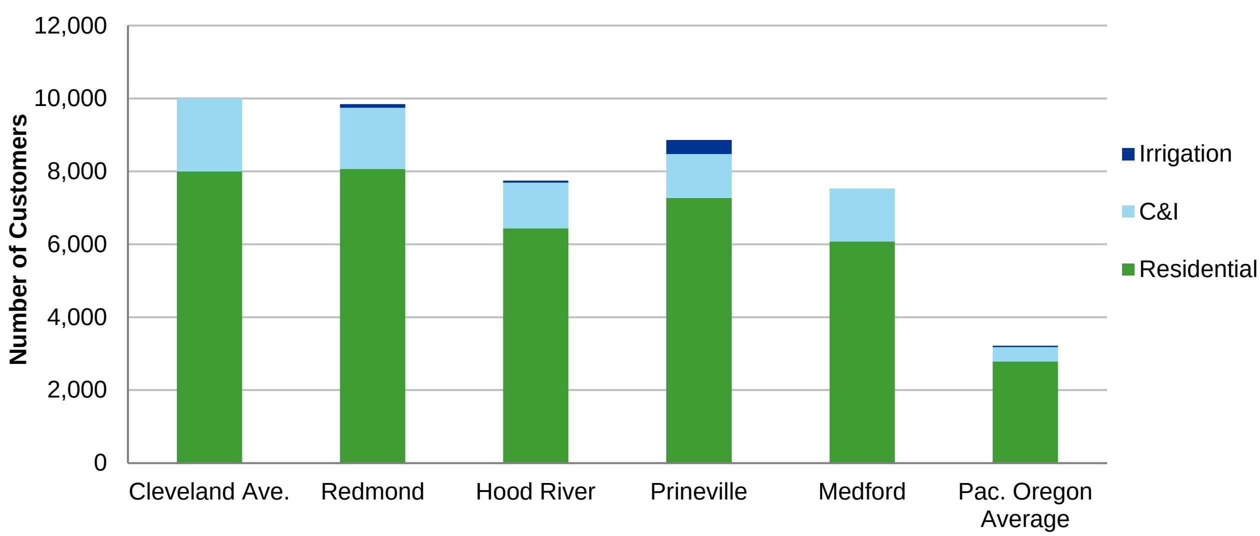
Figure D-6 Private Generation Forecast Disaggregation by Circuit, PacifiCorp Oregon, Base Case



Of the 504 circuits analyzed, the top five (representing 2.6% of customers) account for 5.2% of total forecast capacity, with the top quartile (representing 36% of customers) accounts for 59%.

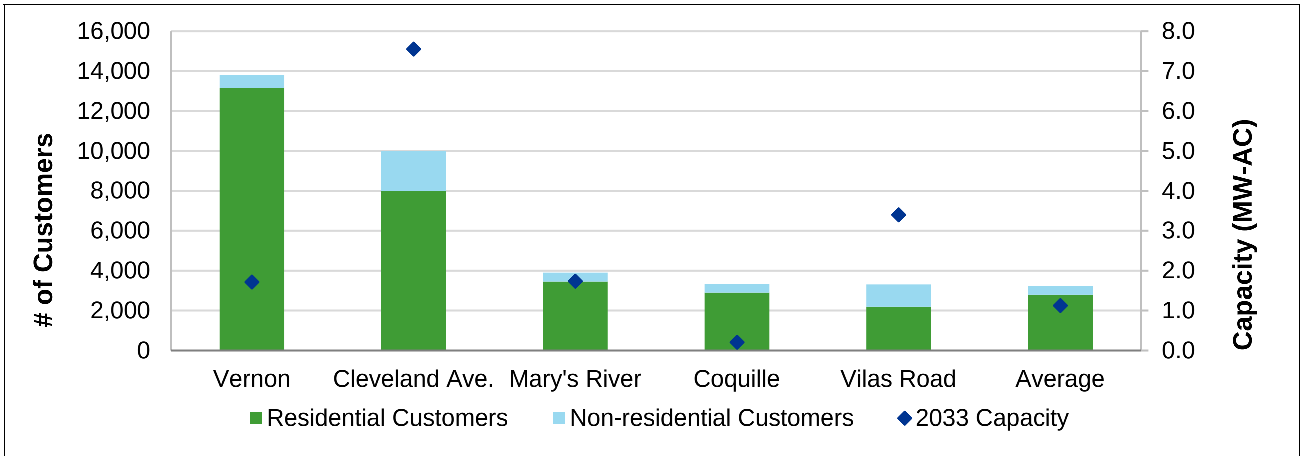
Figure D-7 shows the breakdown of customers, by sector, at the top five substations. Because capacity sizes are larger for irrigation, commercial and industrial customers than for residential (four times larger for irrigation, nine times for commercial and 17 times for industrial), C&I customers contribute to capacity totals disproportionately to their share of the customer population. New construction has a two-fold impact on the capacity forecast: Directly, since there are customers on the substation who could adopt private generation, and indirectly, since new construction has a higher propensity to adopt solar (with and without storage) than existing buildings. All substations except Hood River are in areas where population growth is higher than the statewide average.

Figure D-7 Customer Mix of Top Five Substations Compared to the Average of All Substations



With 193 substations across the state and so many factors influencing the disaggregated forecast, it is not feasible to conduct a deep dive of each substation's capacity forecast. Instead, we selected five substations to illustrate how different underlying factors affected their capacity allocations (see Figure D-8). These substations were chosen to illustrate a range of characteristics influencing adoption, not because they are of special interest for planning.

Figure D-8 Customer Attributes of Selected Substations Compared to Average PacifiCorp Oregon Substation



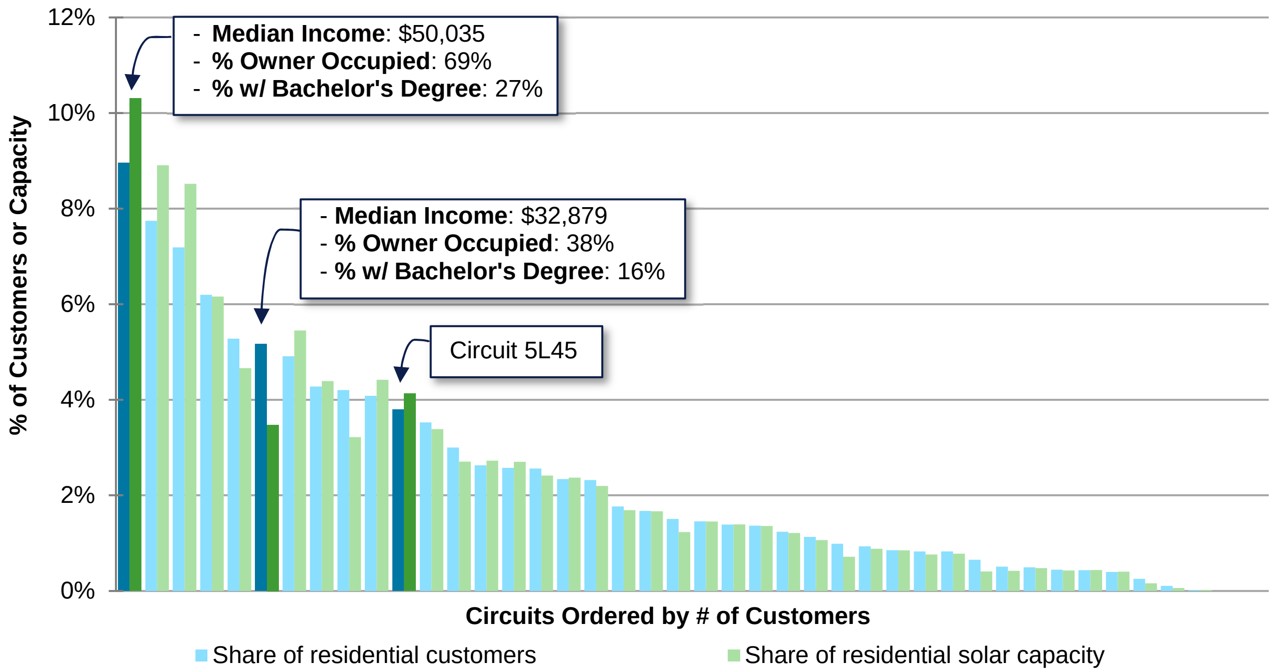
Substation Attribute	Vernon	Cleveland Ave.	Mary's River	Coquille	Vilas Road	Average
Operating Area	Portland	Bed/ Redmond	Corvallis	Coos Bay/Coquille	Medford	--
Climate (for Solar)	Less favorable	More favorable	Less favorable	Less favorable	More favorable	--
Population Growth	1.0%	2.0%	1.3%	0.0%	1.7%	1.0%
% Non-res. Customers	5%	20%	12%	13%	34%	16%
Current Res. Solar Penetration	1.4%	3.0%	3.1%	0.9%	2.4%	1.8%
Home Ownership Rate	70%	55%	61%	77%	75%	65%
Avg. Household Income	$108,604	$136,460	$102,301	$74,543	$58,752	$87,499

Vernon and Cleveland Avenue are among PacifiCorp's top substations by number of customers but have very different climates and customer mixes. Cleveland Avenue lies on the east side of the Cascades and receives more sunshine, while Vernon is in the Portland operating area, which has more rain and more cloudy days which impacts solar generation and thus adoption. Nonresidential PV systems are larger than residential systems (modeled commercial systems are 9 times larger; industrial systems are 17 times larger), so Cleveland Ave's higher share of nonresidential customers (20%) increases its capacity forecast compared to Vernon, with only 5% nonresidential customers. Cleveland Avenue also has double the rate of expected population growth that Vernon does over the next decade.

The remaining three substations shown each have a total customer count close to the state-wide average, but very different capacity forecasts. Mary's River has high historic adoption and higher-than-average population growth, but less non-residential and a lower home ownership rate than average resulted in a share of capacity almost proportional to the number of customers. Coquille has very low historic adoption, perhaps due to its less favorable climate for solar generation, and no expected population growth. Those factors, paired with lower-than-average income and low share of non-residential customers led to a very low level of forecast private generation capacity. The last substation we wish to highlight is Vilas Road in the Medford operating Area. This substation has a very high share of non-residential customers at 34%, and the higher capacity systems for these customers drives up the forecast. A favorable climate for solar with high historic adoption (residential and commercial) led to this substation being allocated a higher-than-proportional share of capacity.

Figure D-9 zooms in on the Klamath Falls operating area to compare how the allocation of PV only capacity compares to the distribution of customers by circuit. For each circuit in the Klamath Falls operating area, the chart shows the share of residential customers to the corresponding share of the 2033 residential PV Only capacity forecast. The figure demonstrates visually that more favorable factors for adoption, such as higher rates of home ownership, higher income, higher education, etc. result in a higher than proportional allocation of capacity.

Figure D-9 Share of Residential Customers vs. Share of Residential PV Only Capacity in 2033, Klamath Falls Operating Area



D.3 Conclusions

As part of the DSP, PacifiCorp evaluated each of the previously discussed private generation scenarios. However, as the baseline DSP private generation forecast, PacifiCorp considers the base case forecast to be most appropriate for planning, given current technology costs, incentive levels and net metering policies in place in Oregon.

Our analysis incorporated the current rate structures and tariffs offered to customers in Oregon. Time-of-use rates, tiered tariffs and retail tariffs that include high demand charges increased the value of PV + Battery configurations compared to PV-Only configurations while other factors such as load profiles and DER compensation mechanisms minimized the impact of such tariffs on the customer economics of PV + Battery systems. The DER compensation mechanism in Oregon — traditional net metering — does not incentivize PV + Battery storage co-adoption.

The sensitivity analysis found a greater difference between the base case and the upper bound of private generation adoption than the base case and lower bound of adoption. The low case assumed higher technology costs and lower retail electricity rates than the other cases, reducing the economic appeal of private generation despite incentives being unchanged. For the high case, an assumed extension to the residential federal investment tax credit provided a significant boost to adoption alongside the lower technology costs and higher retail electricity rates used in that analysis. The resulting new capacity in 2033 is about 31% less than the base case, while the high case is 84% greater than the base.

D.3.1 Future Work

Developing the circuit-level adoption models within the Oregon adoption model revealed additional areas of research related to private generation and behind-the-meter battery storage adoption that would enhance future work. The following is a list of potential future enhancements to this study:

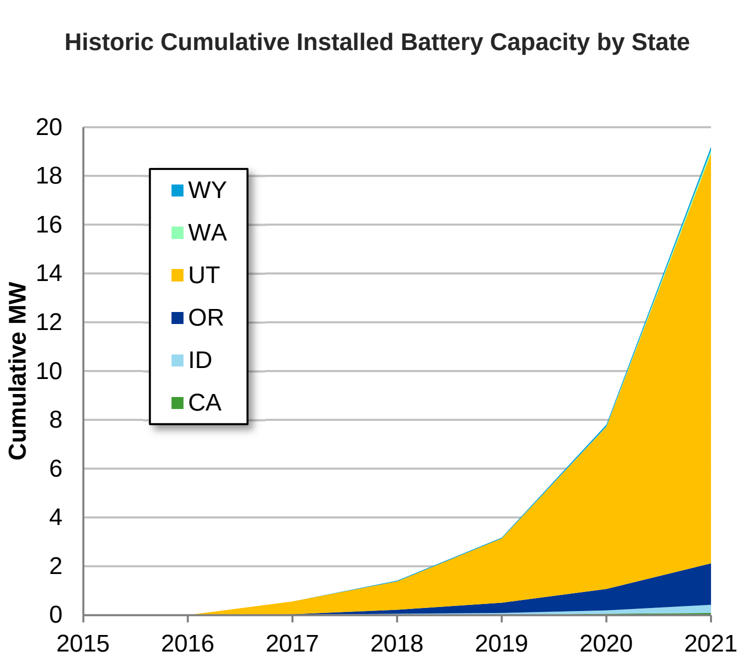
1. A more nuanced approach to the new construction forecast would consider the creation of new circuits in high-growth areas. The current study allocates new construction only to existing circuits.
2. The distribution analysis requires integrating data at different geographical resolutions (state, county, census tract and circuit). While PacifiCorp's data mapped circuits geographically, there were challenges in matching customer billing data to circuits. This study also used existing customer counts by sector by circuit, but corresponding energy use could not be calculated at the circuit-level. Similarly, existing private generation could only be mapped at the county level since interconnection data had incomplete customer circuit information. Future studies will benefit from the circuit-level load forecasts PacifiCorp is developing for this DSP.
3. Storage dispatch modeling would benefit from a finer disaggregation of large commercial and industrial load shapes. Technology that is not broadly cost-effective could still be beneficial for customers with certain load profiles that were not visible using class-level load shapes.
4. Resilience appeared to be a significant driver of adoption. For PV + Battery storage, resilience could be a more significant driver of adoption than economics. A deeper understanding of what customer-types value resilience and how that affects their willingness to pay would help refine the forecast.

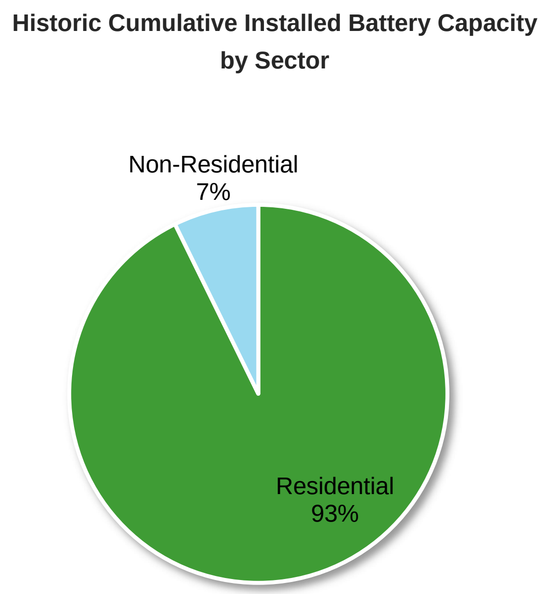
APPENDIX E BEHIND-THE-METER BATTERY STORAGE FORECAST

DNV prepared a behind-the-meter battery storage forecast as a part of the Long-Term Private Generation (PG) Resource Assessment for PacifiCorp covering their service territories in Utah, Oregon, Idaho, Wyoming, California, and Washington to support PacifiCorp's 2023 Integrated Resource Plan (IRP). This study evaluated the expected adoption of behind-the-meter battery storage systems coupled with PV systems over a 20-year forecast horizon (2023-2042) for all customer sectors (residential, commercial, industrial, and agricultural). Residential and non-residential battery energy storage systems (BESS) can be installed as a standalone system, added to an existing PV system, or the system can be installed together with a new PV system. DNV assumed all battery installations would be paired with a PV system in an AC-coupled configuration, as standalone systems are ineligible for the federal ITC—explained further in section 3.2.5.

The adoption model DNV developed for this study is calibrated to the current[26] installed and interconnected behind-the-meter battery capacity that is paired with a PV system, shown in Figure E-1.

Figure E-1 Historic Cumulative Installed Behind-the-Meter Battery Storage Capacity, PacifiCorp, 2012-2021





E.1 Study Methodologies and Approaches

DNV modelled two technologies in the behind-the-meter battery storage forecast:

1. **PV + Battery**: BESS product installed together with a new PV system,
2. **Battery Retrofit**: BESS product installed as an add-on to an existing PV system.

26 PacifiCorp private generation interconnection data as of February 2022.

DNV used the same forecasting methodologies and approaches for the BTM battery storage forecast as the private generation forecast. The methods used to develop the results of the forecast are described in detail in section 3.4 of the report.

Data on battery system costs used in the BTM battery storage forecast is explained in detail in section 3.1.1.2 of the report. That section includes current and projected future costs of battery storage systems used in the forecast for the different sectors. The detailed assumptions for the system configurations, including system sizes, in each sector and state can be found in Appendix A.

E.1.1 Battery Dispatch Modelling

DNV utilized its proprietary solar plus storage operational modeling tool—Lightsaber—to model battery dispatch. Battery dispatch strategy dictates the flow of energy between the PV system, battery, and the grid. The battery dispatch model includes strategies such as peak shaving, energy arbitrage, and manual dispatch. Self consumption was modelled for all sectors' BESS control strategy, which utilizes the battery by charging only from excess PV and discharging if PV production falls below load. For residential customers, the dispatch model used energy arbitrage to reduce time-of-use charges. For non-residential customers, the dispatch model used energy arbitrage to reduce demand charges and time-of-use charges, where applicable.

E.2 Results

In the base case scenario, DNV estimates 227 MW of new battery storage capacity will be installed in PacifiCorp's service territory over the nest twenty years (2023-2042). Figure E-2 shows the relationship between the base case and low and high case scenario forecasts. The low case scenario estimates 151 MW of new capacity over the 20-year forecast period—compared to base case, retail rates increase at a slower rate and technology costs decrease at a slower rate. In the high case, retail rates increase at a faster rate and technology costs decrease at a faster rate—this results in 264 MW of new private generation capacity installed by 2042. The twenty year total new capacity forecasted in the high case is about 16% greater than the base case, while the low case is 34% less.

Table E-1 Cumulative Adopted Battery Storage Capacity by 2042, by Scenario

SCENARIO	CUMULATIVE CAPACITY (2042 MW)
Base	227
Low	151
High	264

Figure E-2 Cumulative New Battery Storage Capacity Installed by Scenario (MW), 2023-2042

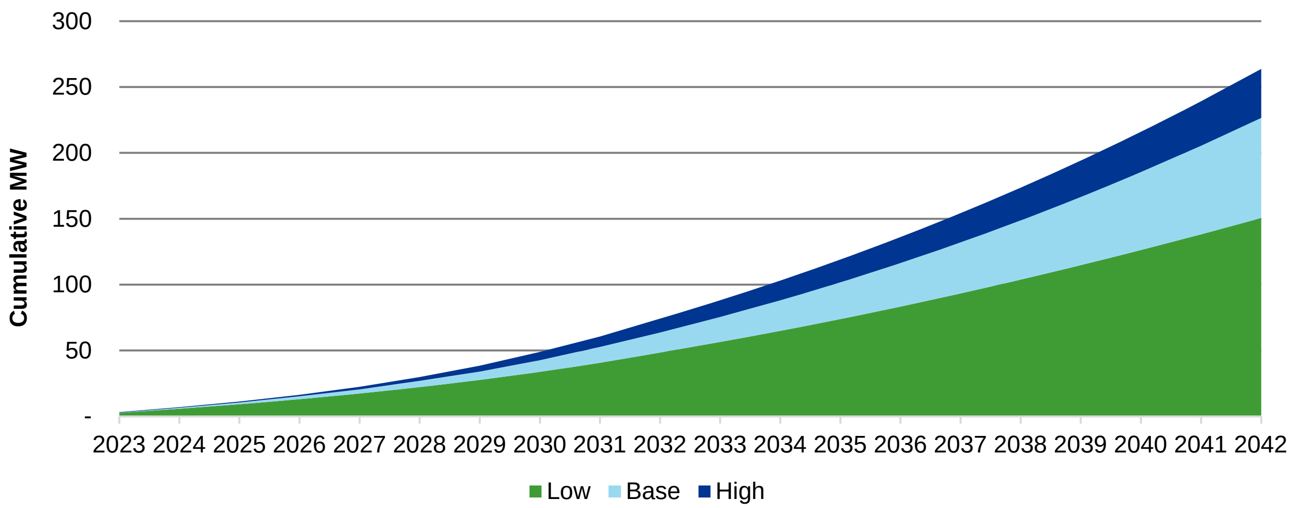


Figure E-3, Figure E-4, and Figure E-5 show the forecasts by customer sector and technology for each scenario. In all scenarios of the forecast, the residential sector represents about 90% of the new battery storage capacity forecasted to be installed over the next twenty years. The commercial, industrial, and irrigation sectors have been bundled into a single “Non-Residential” sector for the purpose of presenting the results in the report, as the capacity forecasts in the individual sectors are very small relative to the total forecast. PV + Battery systems represent the greatest share of the new battery capacity forecasted in the base and high cases. Battery Retrofit systems representing a greater share of the new battery capacity forecasted in the low case indicates that customers are more likely to adopt a PV Only system over a PV + Battery system when technology costs are higher and electricity rates are lower.

Figure E-3 Cumulative New Battery Storage Capacity Installed by Technology (MW), 2023-2042, Base Case

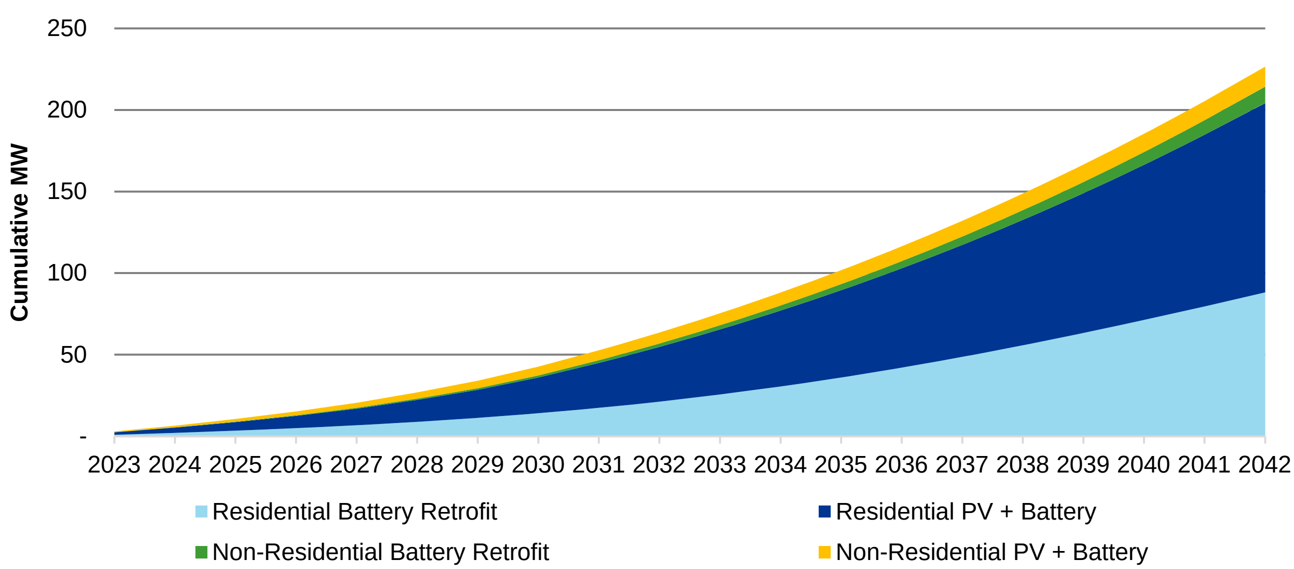


Figure E-4 Cumulative New Battery Storage Capacity Installed by Technology (MW), 2023-2042, Low Case

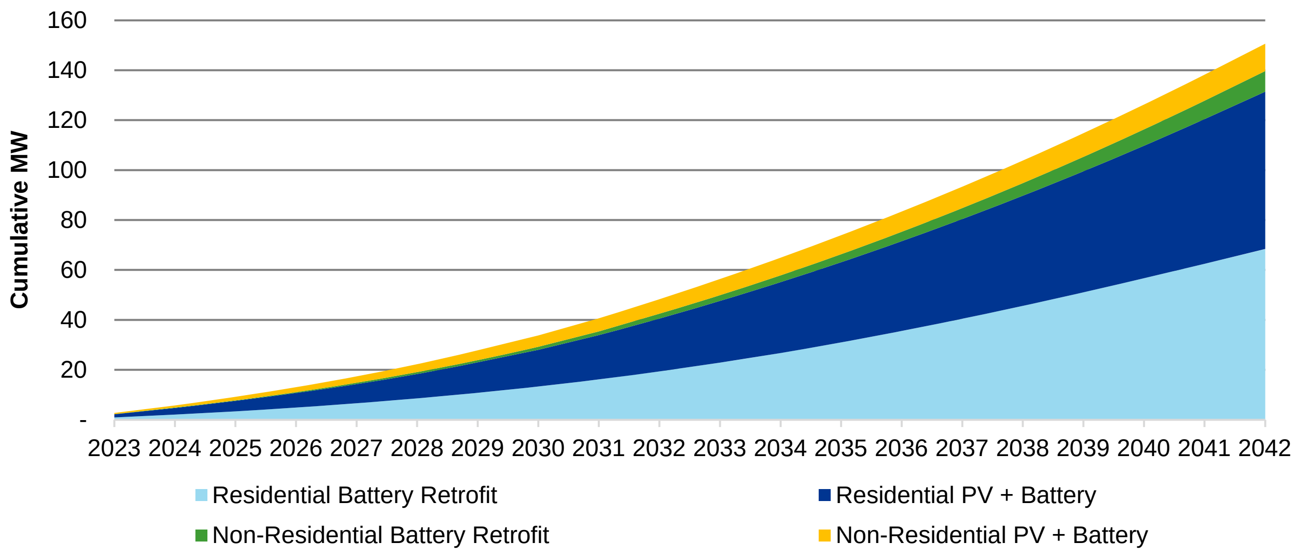
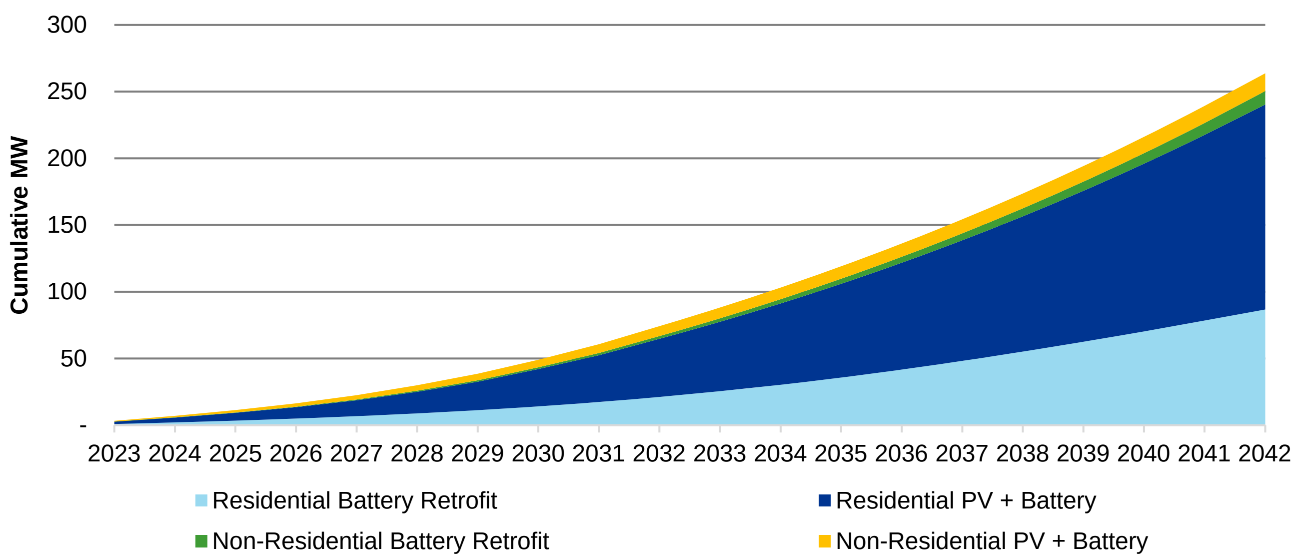


Figure E-5 Cumulative New Battery Storage Capacity Installed by Technology (MW), 2023-2042, High Case



E.3 Storage Capacity Results by State

As was the case in the private generation forecast, Utah represents the largest share of the battery capacity forecast. To date, the majority of installed battery storage capacity and annual growth in storage capacity has been in Utah, which represents the largest portion go PacifiCorp’s customer population. Battery adoption is expected to continue to grow in Utah, with the state’s share of total new capacity reaching between 81% and 84%, depending on the scenario, over the next twenty years. The net billing structure in place in Utah incentivizes PV + Battery storage co-adoption more so than traditional net metering, as customers can lower their electricity bills by charging their batteries with excess PV generation and dispatching their batteries to meet on-site load during times of day when retail energy prices are high. Oregon represents the second largest portion of the new capacity forecasted, between 8% and 10%. Net metering is the DER compensation mechanism in place in Oregon, but customer economics are boosted by PV + Battery incentives provided through the Oregon Department of Energy[27].

Figure E-6 Cumulative New Battery Storage Capacity Installed by State (MW), 2023-2042, Base Case

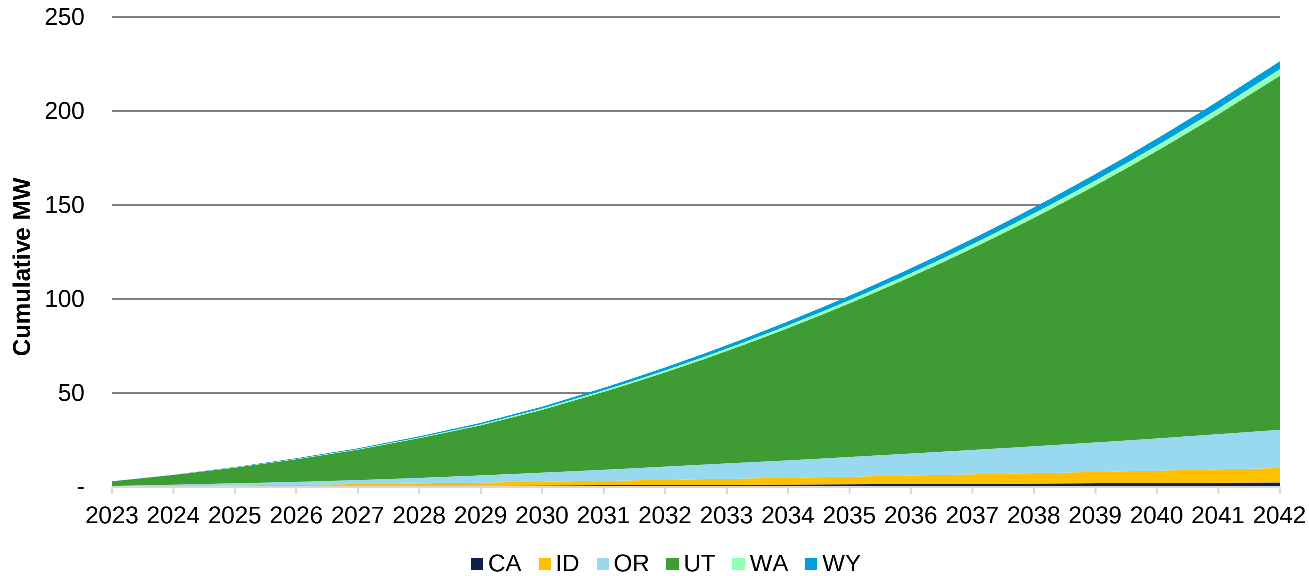
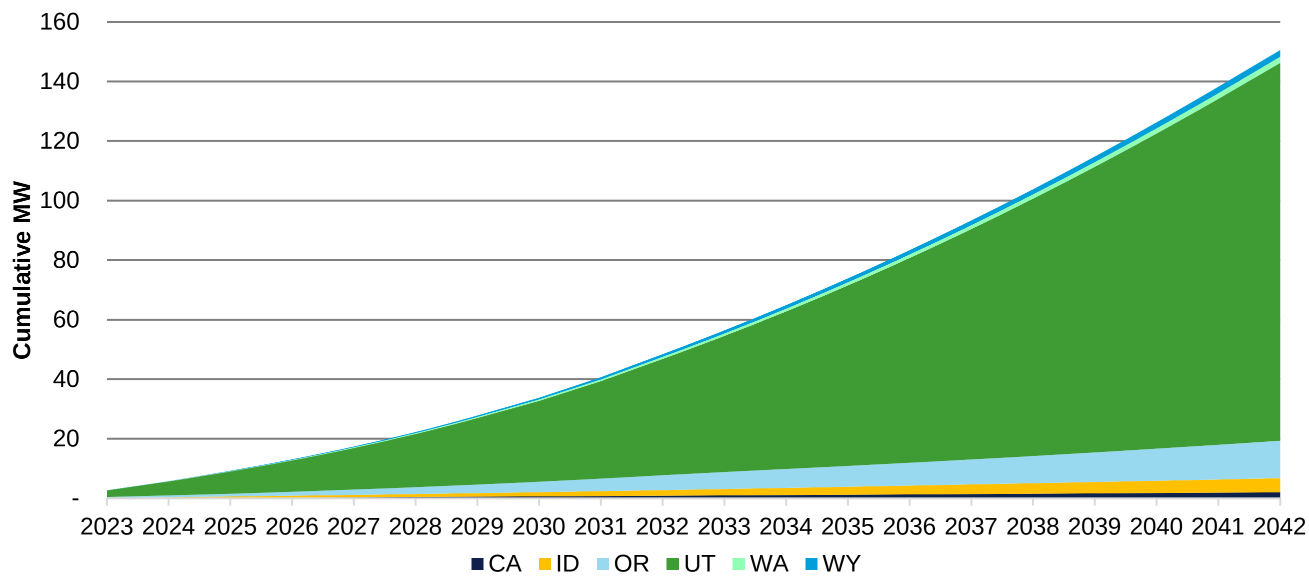
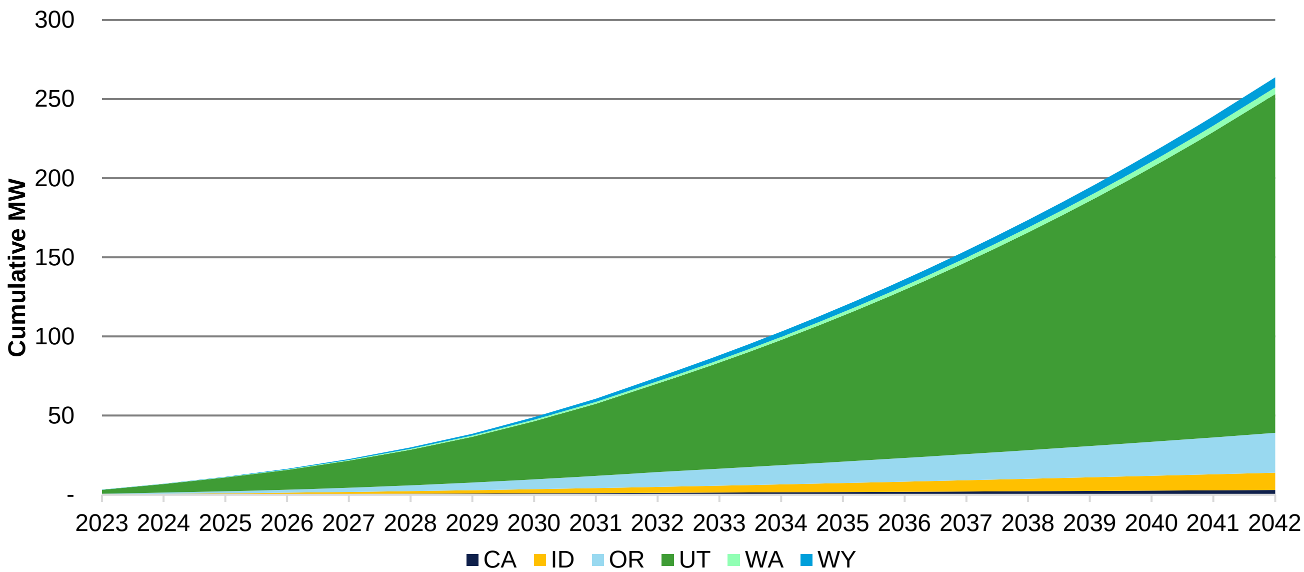


Figure E-7 Cumulative New Battery Storage Capacity Installed by State (MW), 2023-2042, Low Case



[27] https://www.oregon.gov/energy/Incentives/Pages/Solar-Storage-Rebate-Program.aspx

Figure E-8 Cumulative New Battery Storage Capacity Installed by State (MW), 2023-2042, High Case



The following figures show the state-level forecasts in more detail. Background and commentary on the individual states' results can be found in section 4.1 of the report.

California

Figure E-9 Cumulative New Battery Storage Capacity Installed by Scenario (MW), California, 2023-2042

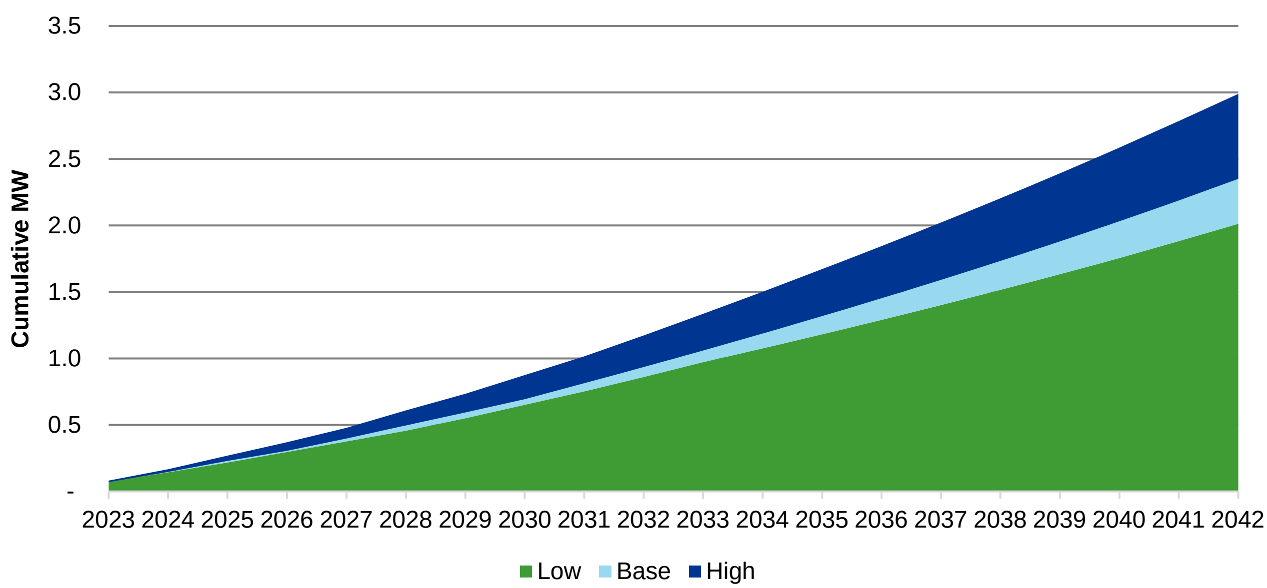
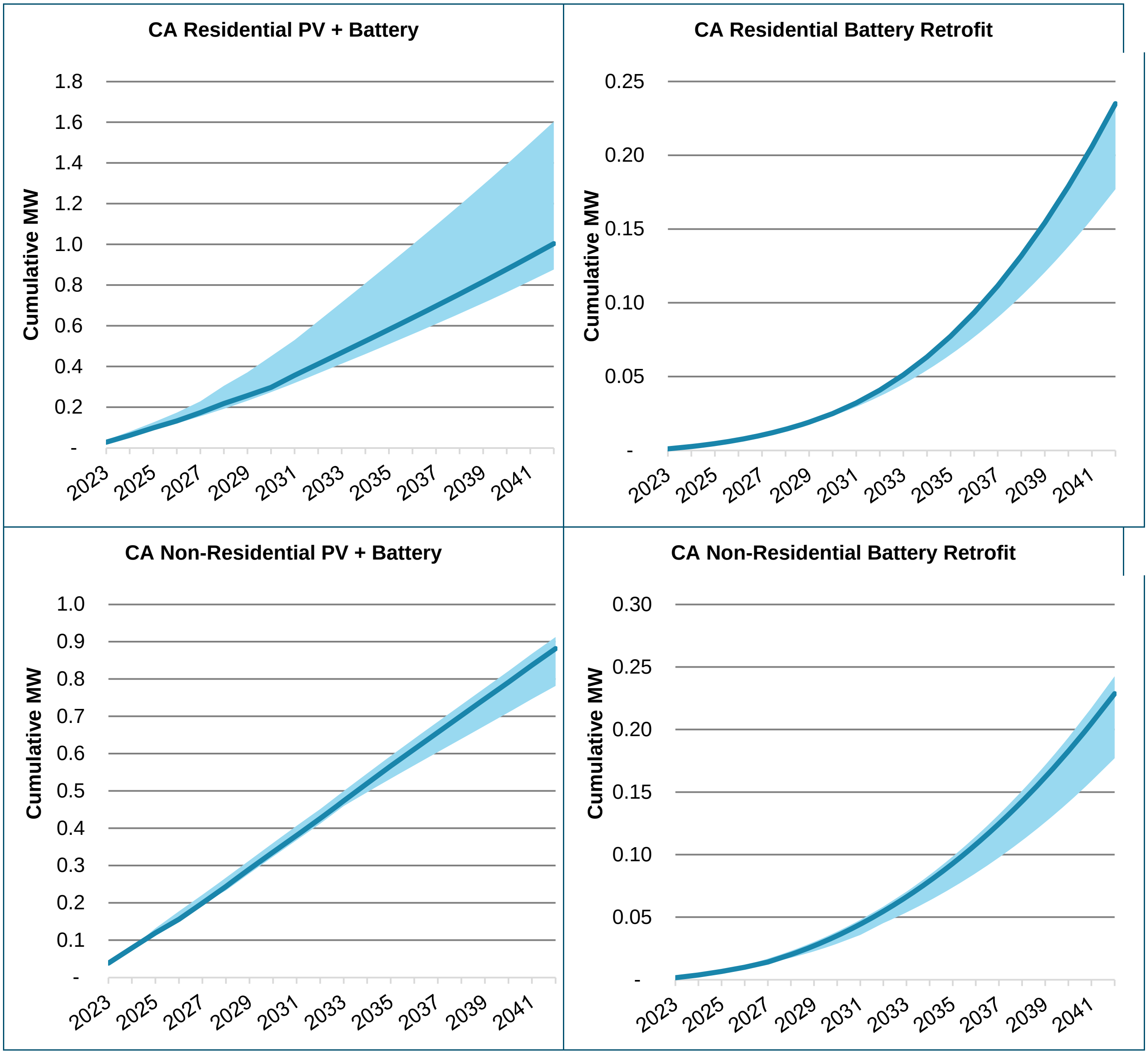


Figure E-10 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), California, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



Idaho

Figure E-11 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Idaho, 2023-2042

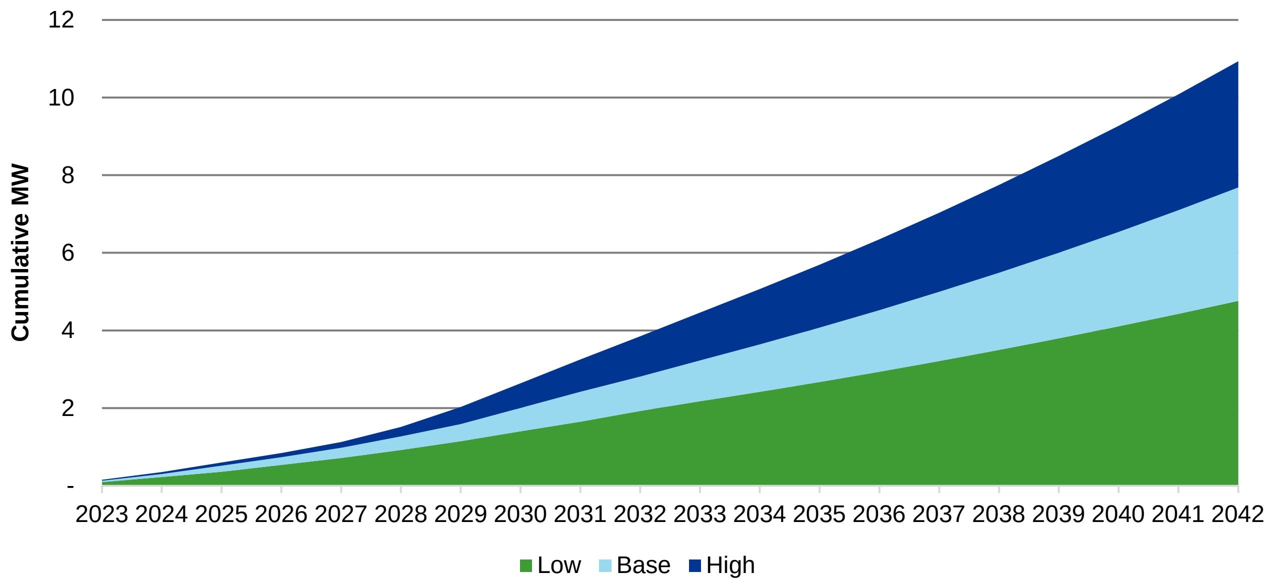
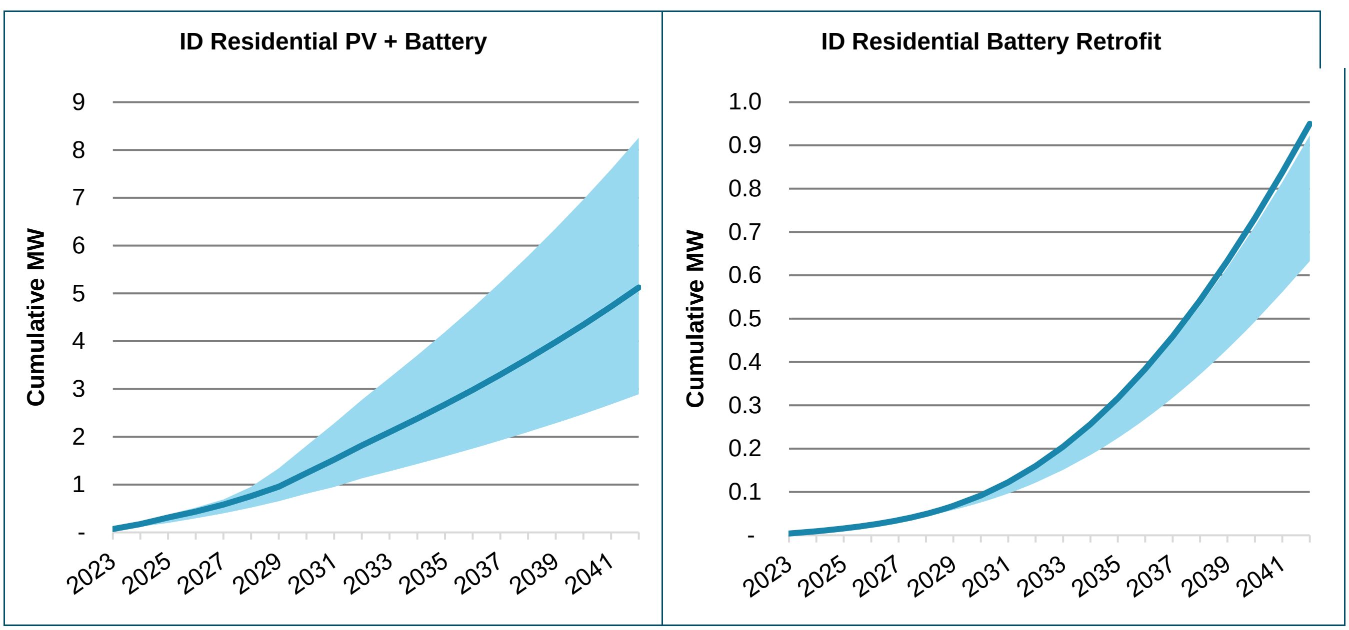
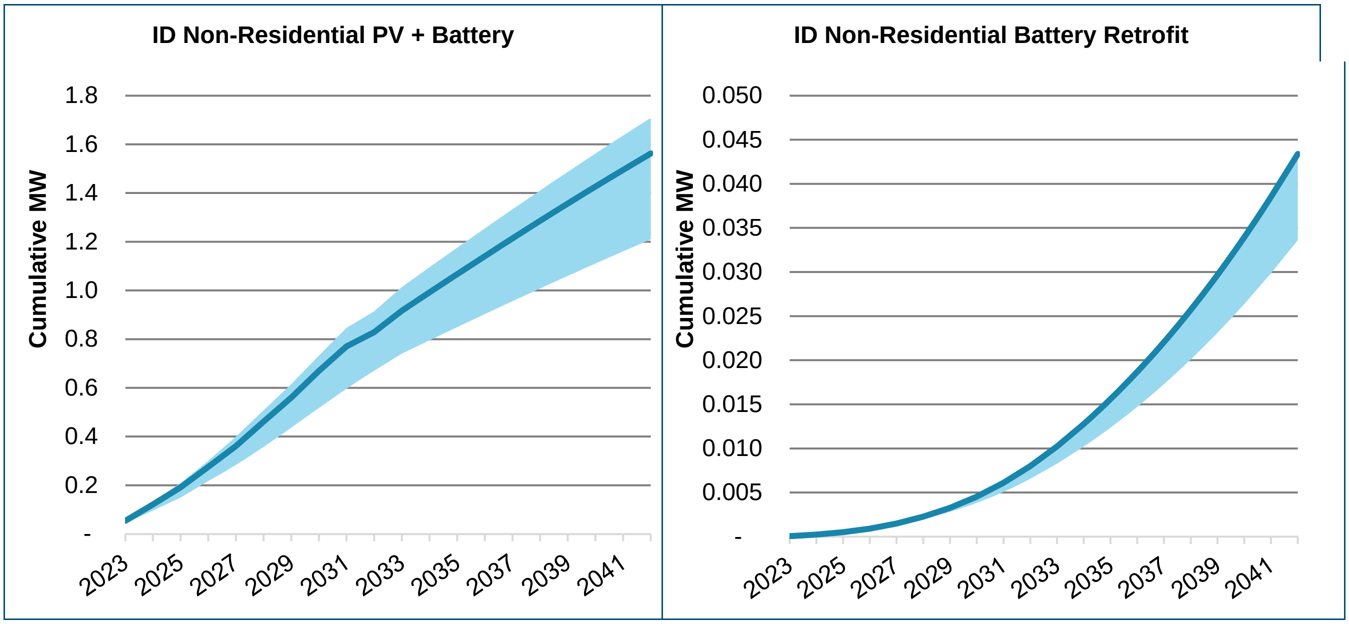


Figure E-12 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Idaho, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.





Oregon

Figure E-13 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Oregon, 2023-2042

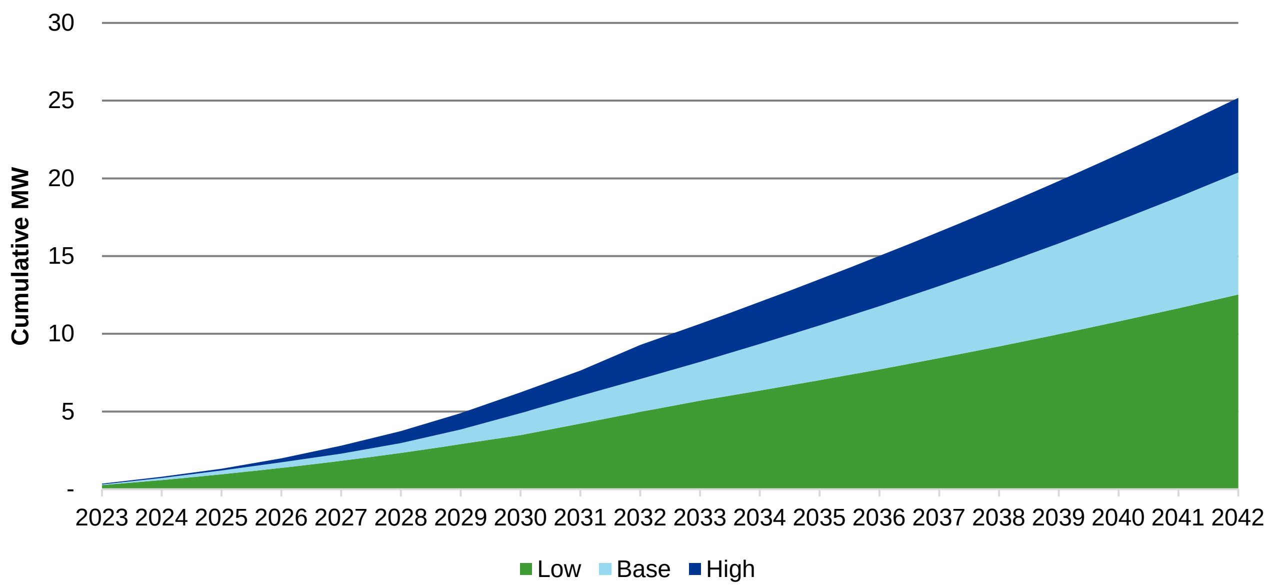
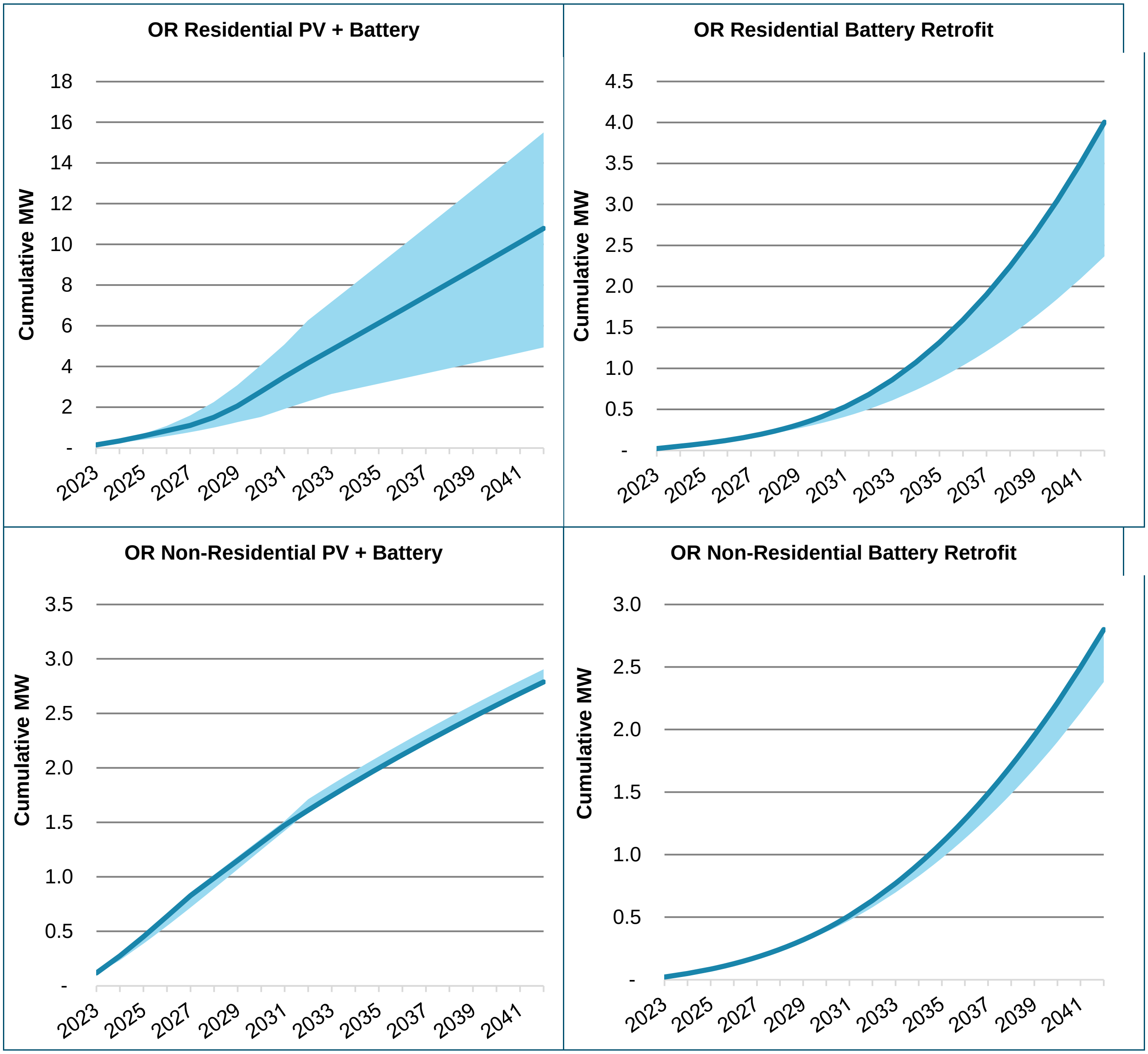


Figure E-14 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Oregon, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



Utah

Figure E-15 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Utah, 2023-2042

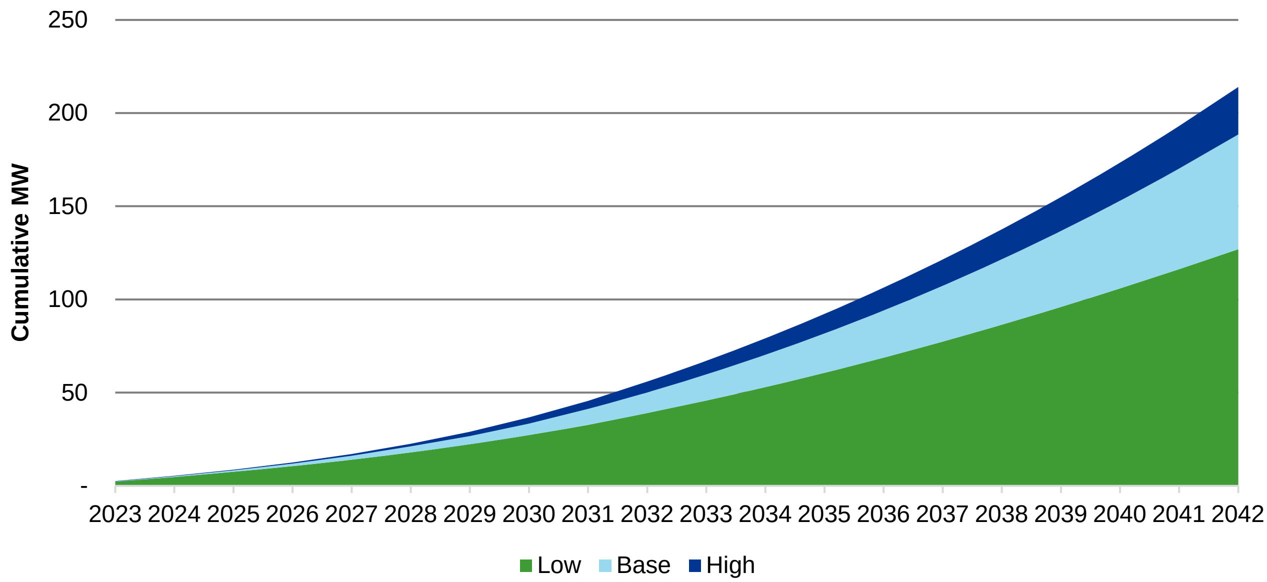
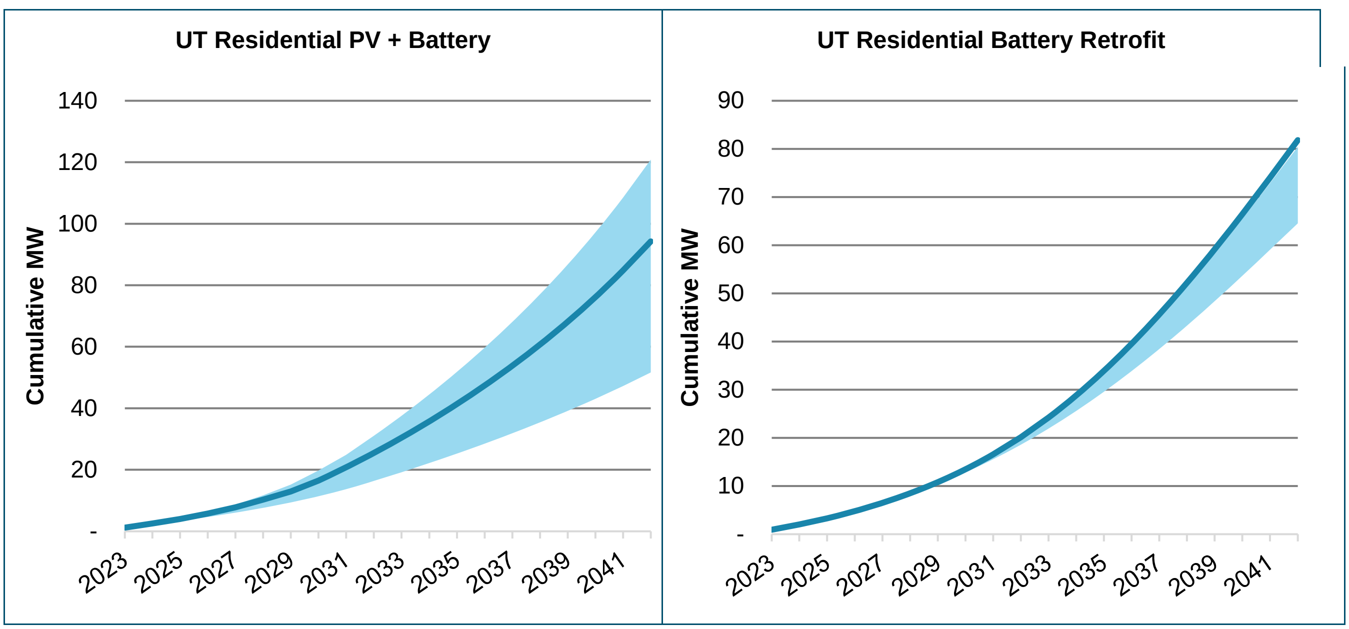
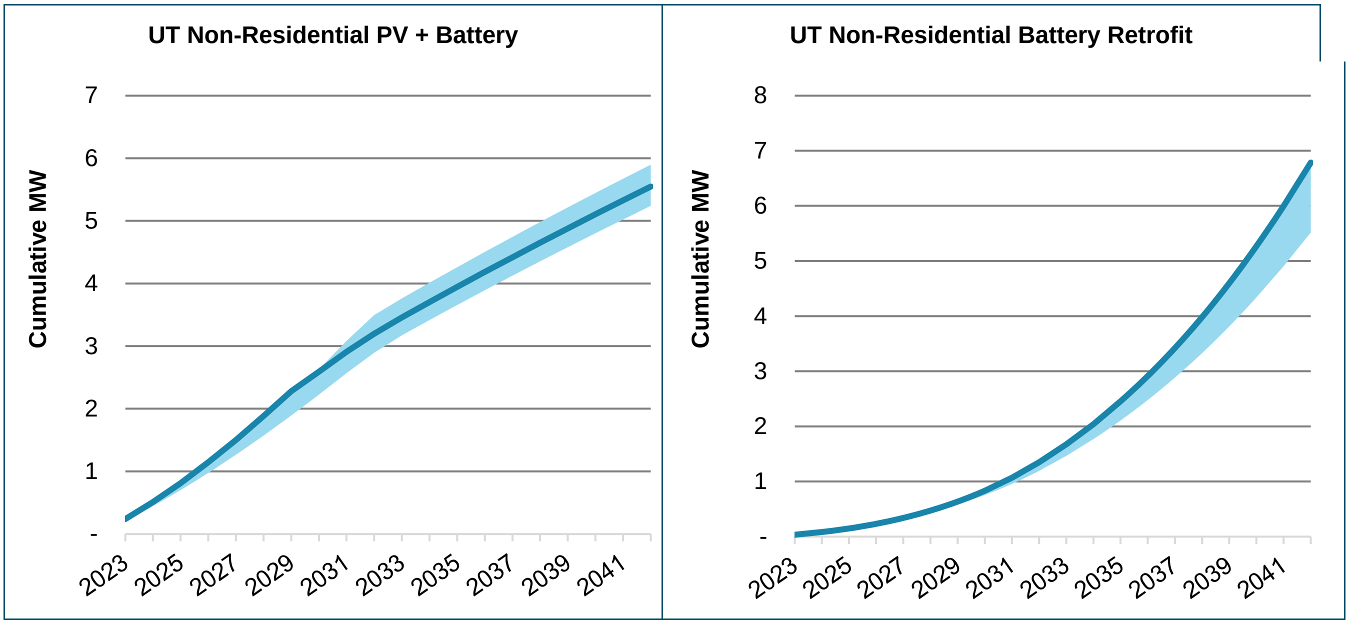


Figure E-16 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Utah, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.





Washington

Figure E-17 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Washington, 2023-2042

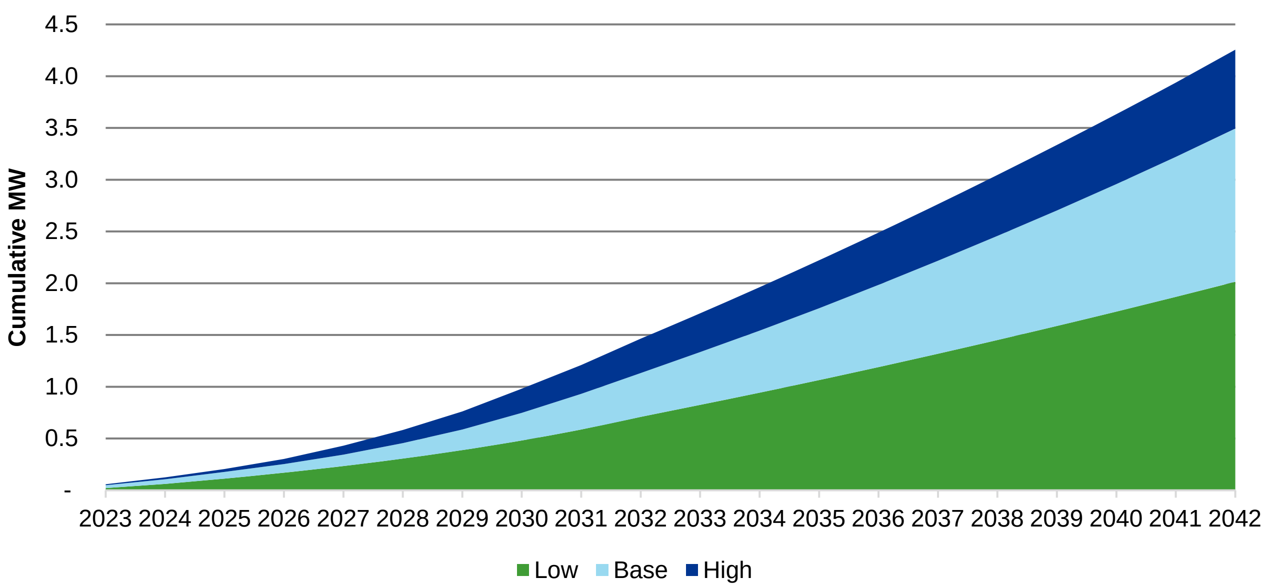
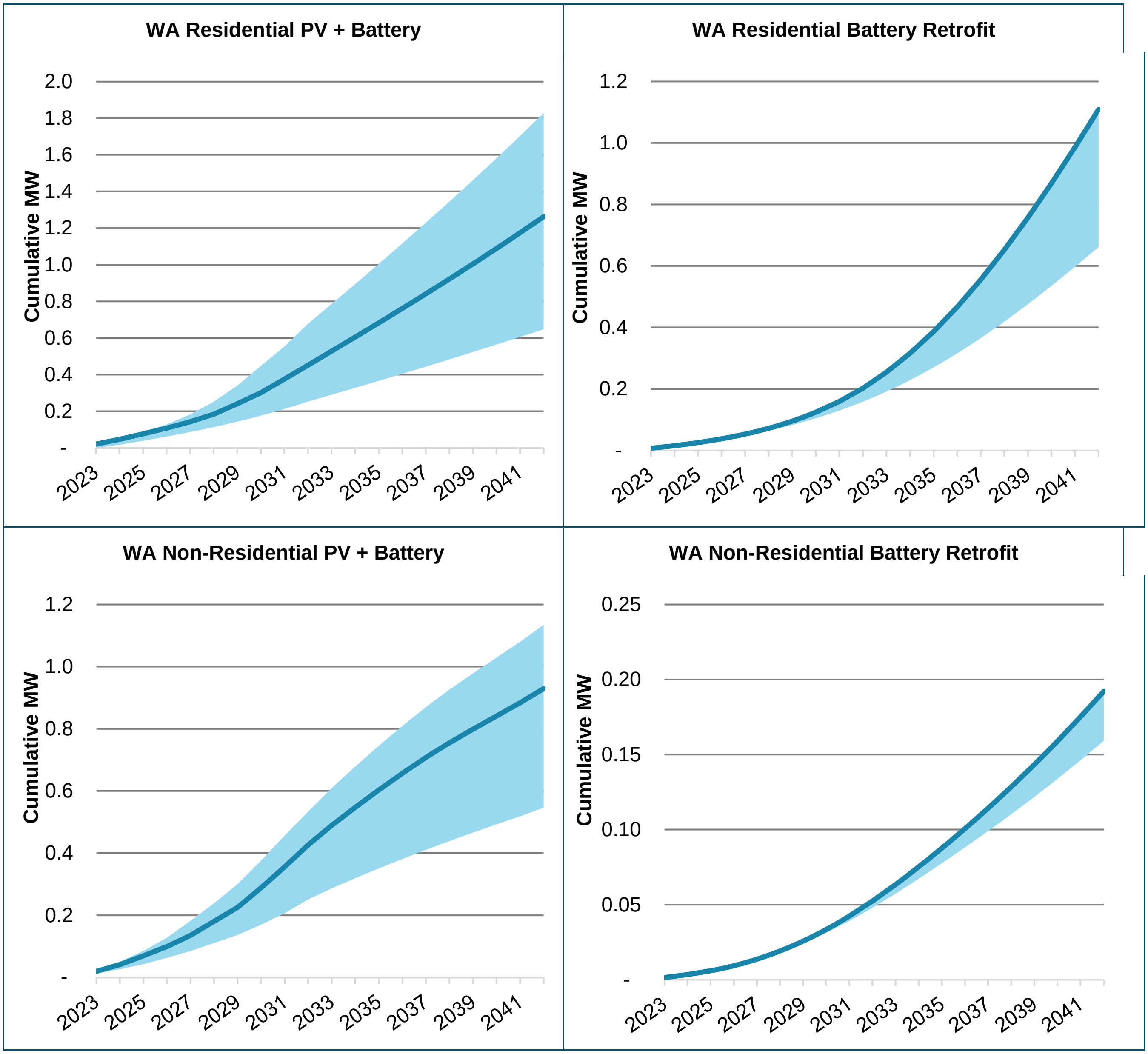


Figure E-18 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Washington, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.



Wyoming

Figure E-19 Cumulative New Battery Storage Capacity Installed by Scenario (MW), Wyoming, 2023-2042

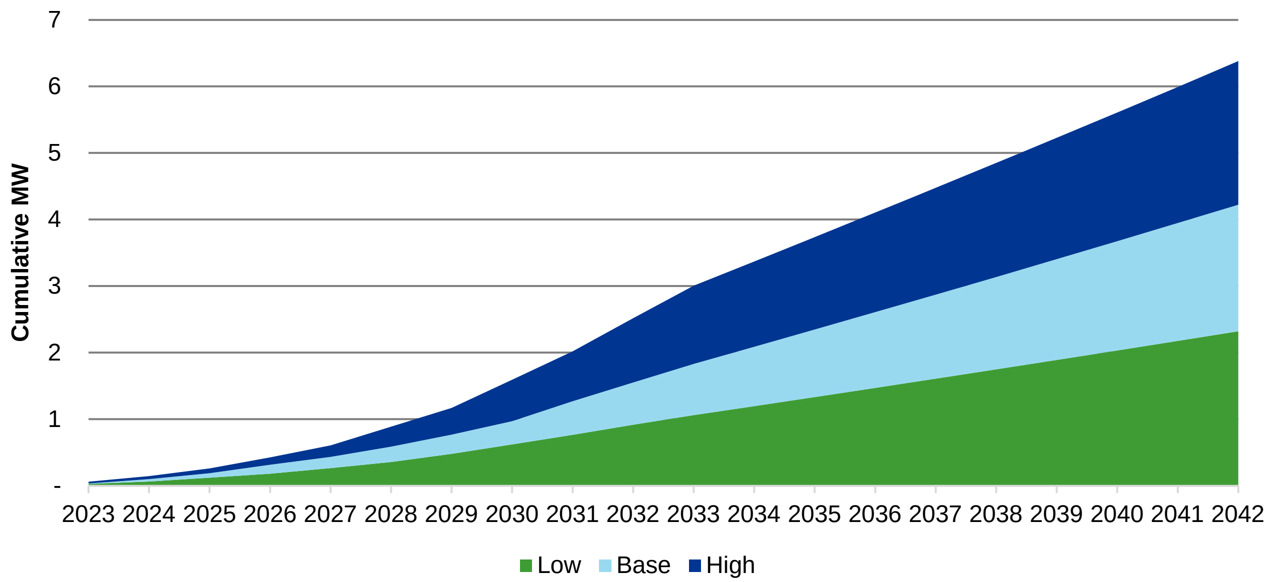
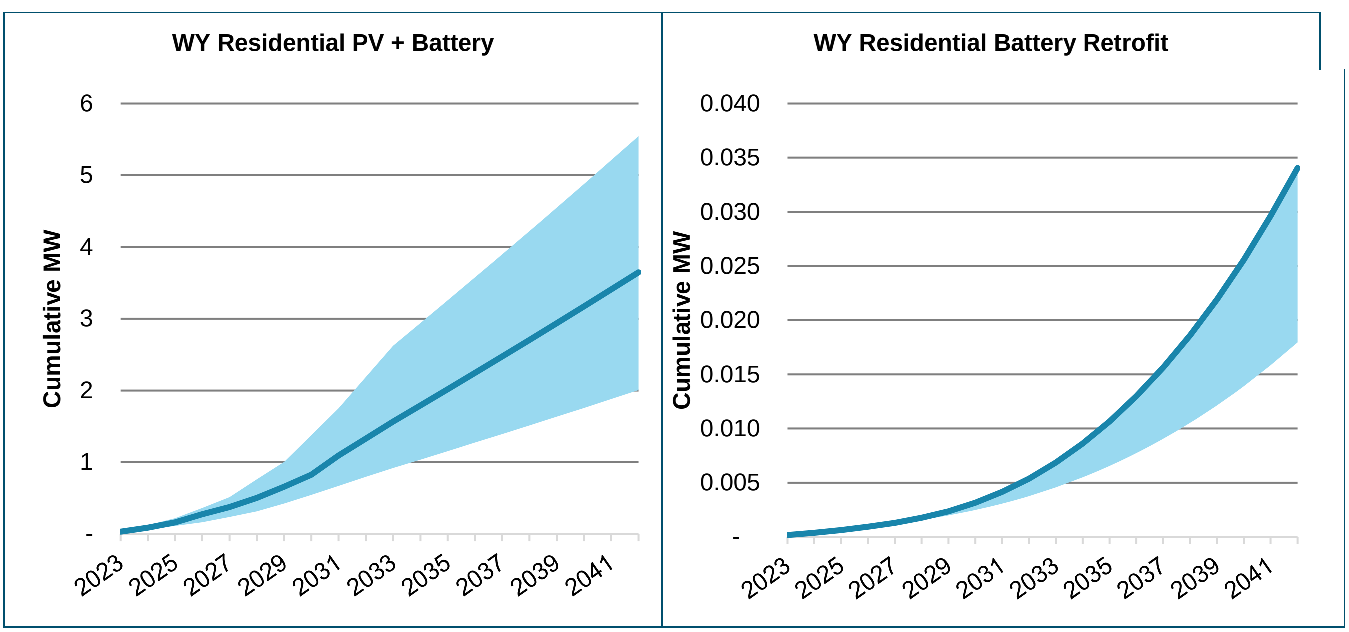
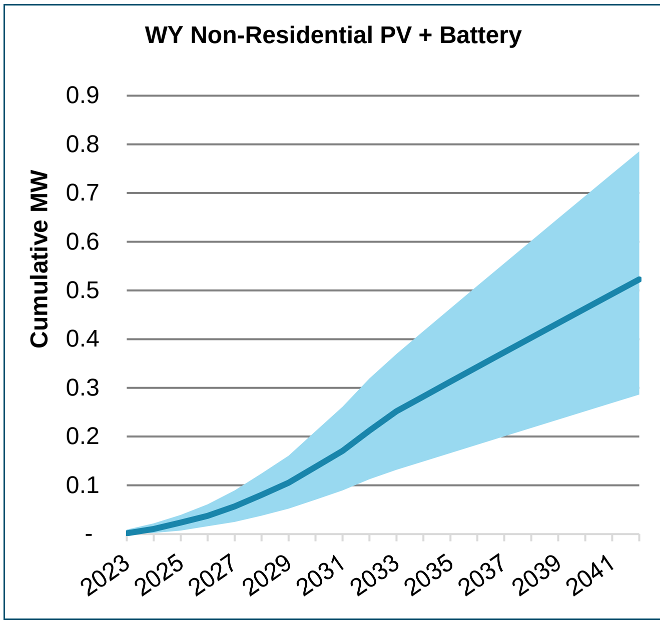
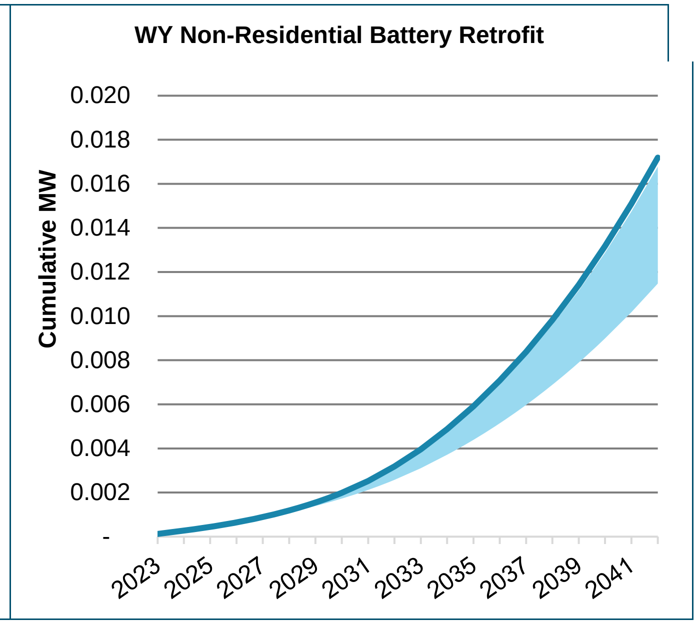


Figure E-20 Cumulative New Battery Storage Capacity Installed by Technology Across All Scenarios (MW), Wyoming, 2023-2042

Upper and lower bounds (in blue) represent the high and low case forecasts, with a line for the base case.




WY Non-Residential PV + Battery
Cumulative MW
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
-
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041


WY Non-Residential Battery Retrofit
Cumulative MW
0.020
0.018
0.016
0.014
0.012
0.010
0.008
0.006
0.004
0.002
-
2023
2025
2027
2029
2031
2033
2035
2037
2039
2041

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APPENDIX M – RENEWABLE RESOURCES ASSESSMENT

A study on renewable resources and energy storage was commissioned to support PacifiCorp's 2023 Integrated Resource Plan (IRP). The "2023 Renewables IRP" Assessment, prepared by WSP is screening-level in nature and includes a comparison of technical capabilities, capital costs, and operations and maintenance costs that are representative of renewable energy and storage technologies. The WSP Assessment builds upon prior studies, updates cost and technical information and adds gravity energy storage options (other than Pumped Hydro Energy Storage, or PHES) and offshore wind (OSW).

This report compiles the assumptions and methodologies used by WSP during the Assessment. Its purpose is to articulate that the delivered information is in alignment with PacifiCorp's intent to advance its resource planning initiatives.

2023 RENEWABLES IRP

PACIFICORP

IRP SUBMITTAL
FINAL

PROJECT NO.: 193579J
DATE: SEPTEMBER 2022

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TABLE OF CONTENTS

TABLE OF CONTENTS

TABLES

CHARTS

TABLE OF CONTENTS

APPENDICES

1 INTRODUCTION

PacifiCorp (Owner) retained WSP to evaluate various renewable energy resources in support of the development of the Owner's 2023 Integrated Resource Plan (IRP) and associated resource acquisition portfolios and/or products. The 2023 Renewable Resources Assessment (Assessment) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and operations and maintenance costs that are representative of renewable energy and storage technologies listed below.

It is the understanding of WSP that this Assessment will be used as preliminary information in support of the Owner's long-term power supply planning process. The level of detail in this study is sufficient to provide screening level data required for the IRP planning process. Past the IRP modeling and selection, technologies of interest to the Owner should be further investigated to refine design, major equipment selection, value engineering, and specific project scope adjustments.

1.1 EVALUATED TECHNOLOGIES

- Geothermal
- Solar
- Wind
  - On-Shore
  - Off-Shore
- Energy Storage
  - Lithium-Ion Battery
  - Flow Battery
  - Gravity Battery
  - Compressed Air
- Solar + Energy Storage
- Wind + Energy Storage
- Wind + Solar + Energy Storage

1.2 ASSESEMENT APPROACH

This report accompanies the Renewable Resources Assessment spreadsheet files (Summary Tables) provided by PacifiCorp (PAC) and Burns and McDonnel (BMcD). The Summary Tables are broken out into three separate files for Geothermal, Solar, Wind, and Energy Storage options. Using the assessment for these individual technologies, this assessment also includes technology combinations of Solar + Energy Storage, Wind + Energy Storage, and Wind + Solar + Energy storage. The costs are expressed in mid-2022 dollars for a fixed price, turn-key resource implementation. The Summary Tables can be found in Appendix A: Summary Tables.

This report compiles the assumptions and methodologies used by BMcD, the National Renewable Energy Laboratory (NREL), the Department of Defense (DoE), the International Renewable Energy Agency (IRENA), the Pacific Northwest National Laboratory (PNNL), and existing WSP experience during this assessment. Its purpose is to articulate that the delivered information is in alignment with PacifiCorp's intent to advance its resource planning initiatives. Each technology and grouped technology have been assessed with a ten-year forecast cost trend.

1.3 STATEMENT OF LIMITATIONS

Estimates and projections prepared by WSP relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. WSP has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance ratings, schedules, etc., may vary from the data provided.

2 STUDY BASIS AND ASSUMPTIONS

2.1 SCOPE BASIS

Scope and economic assumptions used in developing the Assessment are presented below. Key assumptions are listed as footnotes in the summary tables, but the following expands on those with greater detail for what is assumed for the various technologies.

2.2 GENERAL ASSUMPTIONS

The assumptions below govern the overall approach of the Assessment:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes. Estimates concentrate on differential values between options and not absolute information.
- All information is preliminary and should not be used for construction purposes.
- All capital and operations and maintenance (O&M) cost estimates are stated in 2022 US dollars (USD). Escalation is excluded.
- Estimates assume an Engineer, Procure, Construct (EPC) fixed price contract for project execution.
- Capital costs estimates shall be American Association of Cost Engineering (AACE) Class 3 unless otherwise specified.
- Unless stated otherwise, all wind and solar options are based on a generic site with no existing structures or underground utilities and with sufficient area to receive, assemble and temporarily store construction material. Battery options are assumed to be located on existing Owner land.
- Sites are assumed to be flat, with minimal rock and with soils suitable for spread footings.
- Wind and solar technologies were evaluated across five states within Owner's service areas: Washington, Oregon, Idaho, Utah, and Wyoming. The specific locations within each state for potential wind/solar sites were determined by Owner.
- Geothermal technologies were evaluated based on the Owner's existing Dual Flash Blundell Plant and Binary Greenfield Plant.
- All performance estimates assume new and clean equipment.
- Electrical scope is assumed to end at the high side of the generator step up transformer (GSU) unless otherwise specified in Appendix B (most notably for compressed air energy storage).
- AACE Class 5 demolition costs were included for each technology. Costs were developed from published literature from BMcD, NREL, PNNL, DoE, and WSP's experiences; actual rates may vary based on technology and location. Recycling costs are included in the demolition figures; however, re-sale value of materials is excluded as that can vary significantly depending on metals pricing and competition in the currently expanding recycling market. Demolition costs are seen as an optional cost, as Owner could choose other options including repowering the plant.

The current market is being impacted by various trade tariffs on materials as well as on solar modules. Predicting future trends or impacts of these tariffs is beyond the scope of this study. While these costs are intended to represent a snapshot of 2022 pricing, additional volatility could occur when looking at future pricing of these options. These factors may also change the declining costs curves presented in the accompanying spreadsheets.

Energy storage technologies evaluated in this assessment are expected to take advantage of less expensive, off-peak power to charge the system to later be used for generation during periods of higher demand. These storage options provide the ability to optimize the system for satisfying daily energy needs. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers. Additionally, energy storage has a direct benefit to renewable resources as it can absorb excess energy that otherwise would need to be curtailed due to transmission constraints. This could increase the percentage of power generated by clean technologies and delivered during peak hours. Costs and options shown in this assessment represent storage technologies that are designed for one full cycle per day in a scheduled use case. Other use cases such as frequency regulation, voltage regulation, renewable smoothing, renewable firming, and black starting are not accounted for in the options presented in this study. Different use cases will impact the capital cost, O&M, and performance of the various technologies.

The following project indirect costs are included in capital cost estimates:

- Equipment and Materials
- Construction management & Labor Costs
- PII (Permitting, Interconnection, Commissioning)
- Startup spare parts
- EPC Markup
- Owner's contingency
- Builders Risk Insurance
    - Local sales taxes applied to Solar and Wind technologies based on their assumed location.
- Other taxes, such as State taxes, were estimated to current rates and applied based on technology's assumed location.

2.3 OWNER COSTS

Allowances for Owner's costs are not included in the pricing estimates. The cost buckets for Owner's costs are to be determined by PAC. Owner's costs for project development, project management and legal fees vary slightly by technology.

2.4 COST ESTIMATE EXCLUSIONS

The following costs are excluded from all estimates:

- Financing Fees
- Interest during construction (IDC)
- Performance and payment bond
- Off-site infrastructure
- Utility demand costs
- Land Acquisition or Lease costs

2.5 O&M ESTIMATE ASSUMPTIONS

Operations and maintenance (O&M) estimates are based on the following assumptions:

- O&M costs are in mid-2022 USD.
- Nominal 2.5% inflation rate year-over-year
- Fixed O&M Costs
    - Are not dependent on the usage profile of the system
    - Measured in dollars per kilowatt-year ($/kW-yr.)
    - Includes labor costs, fixed maintenance fees, contracted service fees, operational costs, property taxes, land lease, and allowance for future part replacement.
- Variable O&M Costs
    - Are dependent on the usage profile of the system
    - Have been included in fixed O&M costs for all technologies due to limited, inconsistent and/or contradictory public and industry data
    - Includes cleaning and maintenance (scheduled, unscheduled, and general maintenance on technology and transformer(s))

3 GEOTHERMAL

3.1 GENERAL DISCRIPTION

This evaluation, as outlined in the scope of work, includes cost estimates for both Dual Flash expansion of the Blundell Plant, Utah, and general Greenfield Binary Plan (ORC). All cost estimates are based on 200 MW generation with a commercial life expectancy of 40 years or longer. The WSP New Zealand team provided additional help for the Geothermal technology cost estimates, as they have prior experience with both types of plants. The team used a combination of NREL Annual Technology Baseline (ATB) data, International Renewable Energy Agency (IRENA) data, and the "Assessment of Current Costs of Geothermal Power Generation in New Zealand (2007 Basis)" publication from Sinclair Knight Merz for the basis of their analysis. Additional details can be viewed in this deliverable, titles "PacifiCorp Geothermal Project Estimate Support". A summary is provided below.

3.2 PERFORMANCE

All data provided and reviewed from the New Zealand team fits with current industry standards, including reservoir temperature and well production flow rates. The team had to extrapolate costs from 20 and 50 MW scenarios into two 200 MW scenario for the Dual Flash Expansion of the Blundell Plant and the Greenfield Binary Plant, as requested. Additionally, costs had to be converted from $NZ to $US for years 2007 to 2021; based on cost data, project costs were then project to 2022 $US. It is assumed that the Greenfield Binary Plant is in a similar geographic area as the Blundell Plant. Resulting data is provided in Section 3.3.

3.3 COST ESTIMATES

The total capital expenditure (CAPEX) costs for the Blundell Expansion and the Greenfield Binary Plant are $807.66MM and $1,167.99MM, respectively. The primary reason for the discrepancy is the cost of the power plant itself. On a per kW basis, these CAPEX costs result in $4,038 and $5,840 per kW, which both fit within IRENA and NREL estimates. A sample of the EPC cashflow over a 30-month project duration is shown below in Chart 3-1. This cashflow incorporates a relatively slow early construction phase, then spending picks up during the bulk of the construction, followed by a slower pace before the commercial online date in month 31. O&M costs are $23.0MM for both plants. Demolition costs, although very high level given the lack of decommissioned plants, are $23.4MM for both plants. O&M costs for both Dual Flash Blundell and Greenfield Binary Plants, represented for 2022, is $115.00/kW-yr. which falls within a close range of NREL's $105.562/kW-yr. as referenced in Chart 3-2.

Chart 3-1 Geothermal EPC Cashflow

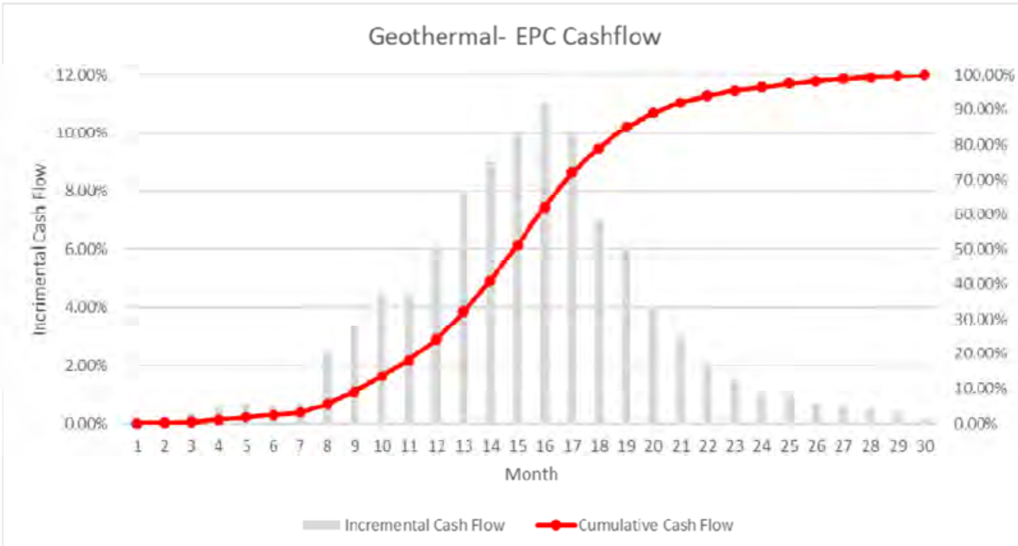
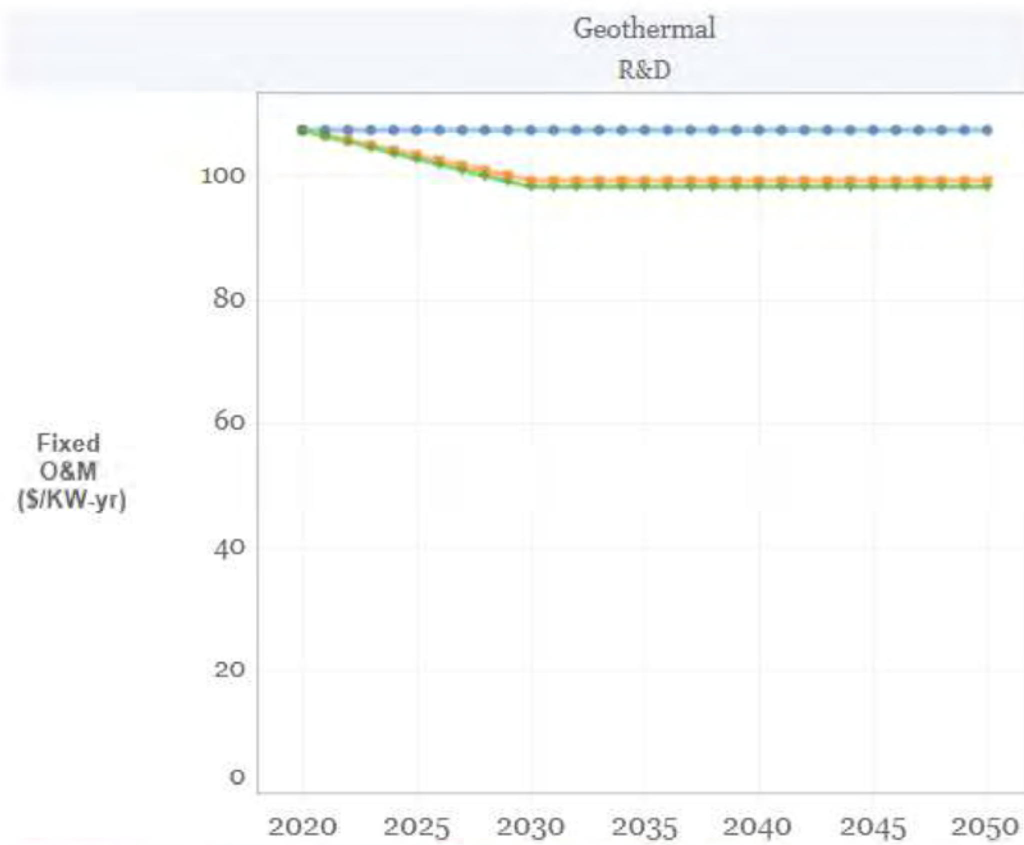


Chart 3-2 Geothermal O&M Cost Trends



Source: "Electricity Annual Technology Baseline (ATB)", NREL, 2020

4 SOLAR PHOTOVOLTAIC

4.1 INTRODUCTION

This evaluation, as outlined in the scope of work, includes cost estimates for both 20 and 200 MW AC single-axis tracking photovoltaic (PV) systems both with a 1.3 DC-AC ratio. All cost estimated are on an AC-capacity basis. PacifiCorp provided performance characteristics of the various location including AC capacity factor, 25-year commercial life, module degradation, and annualized energy production. The five project locations span across PacifiCorp's service territory, as shown below:

Rocky Mountain Power	Pacific Power
Idaho Falls, Idaho	Lakeview, Oregon
Milford, Utah	Yakima, Washington
Rock Springs, Wyoming	

4.2 COST ESTIMATING METHODOLOGY

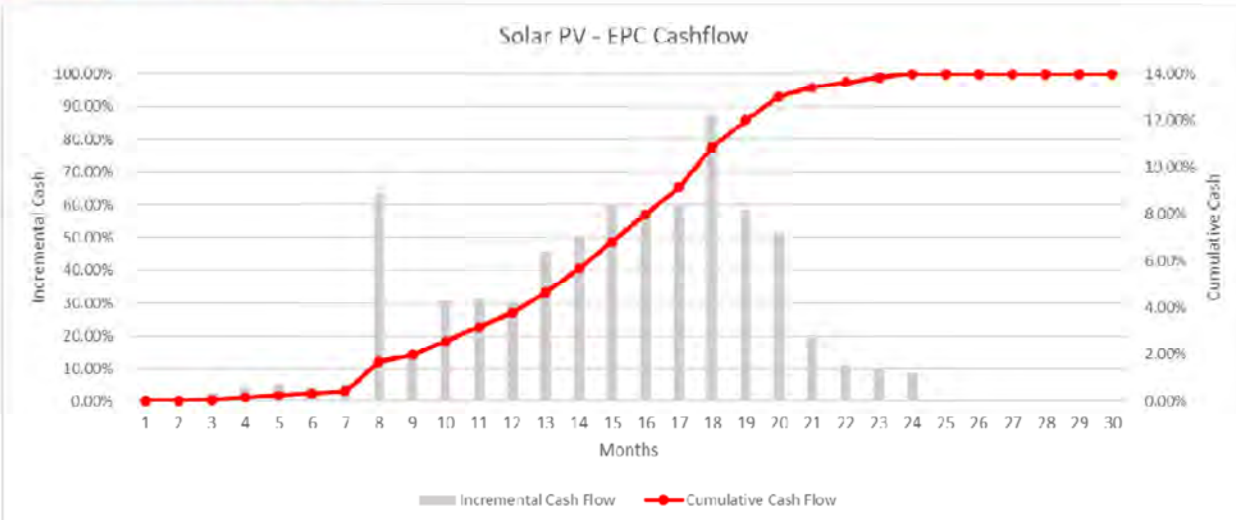
Cost estimates for this evaluation were based upon widely used public information, including the National Renewable Energy Laboratory (NREL), Solar Energy Industries Information (SEIA) data, Lawrence Berkeley National Laboratory (LBNL or "Berkeley Lab"), Pacific Northwest National Laboratory (PNNL), previous WSP project proposals and internal databases, as well as original equipment manufacturer (OEM) and EPC quotes. Locational adjustment factors for the five project locations are from the U.S. Energy information Administration's (EIA) utility-scale capital cost estimates. All publicly available data used for these estimations is found in the bibliography.

EPC overnight project capital costs are presented in 2022 dollars. These costs include the modules, inverters, structural/electrical balance of system (BOS), installer overhead/Labor, and EPC overhead (equipment and material). Additionally, owner's costs include engineering/development overhead, transmission interconnection fees, permitting costs, and developer profit. It is assumed that PacifiCorp will provide the owner's project management, development, and legal cost data points. Overnight capital cost estimations for projects built in future years is shown in Appendix A.

Operations and maintenance costs are presented in 2022 dollars. These costs include cleaning, vegetation management, inspection, replacement, taxes, insurance, asset management, land leases, and operations administration. These costs are calculated as flat yearly rates, and do not change based on the energy output of the system, for the respective system capacity sizes. It is assumed that the land for all five project locations is leased throughout the project lifetime. As land lease rates vary within a single site location, this line item has been reserved for Owner input. Project demolition costs are provided in 2022 millions of dollars, based on multiple publications quoting $30,000 per MW. As noted above, demolition costs are very uncertain, and this estimate does not include the potential to re-sell any equipment.

Total EPC costs are similar for all locations with a 20 MW AC capacity with a range of $21.24-$22.91. This is similarly the case for the 200 MW AC systems, with a range of $174.35-$188.07MM. These costs align with the literature and previous project experience analyzed for this report, which falls between $1,300-$1,400/kW. Although the cost of solar PV development has steadily declined over the past two decades, recent U.S. tariffs along with price increases related to supply-chain shortages and worldwide inflation have provided more uncertainty on cost estimations. WSP believes the projections in this report fall within +/- 30% of the true cost, as is consistent with an AACE Class 4 cost estimate classification system. Estimated EPC cash-flow values for solar PV are shown below in Chart 4-1. This chart shows the low spend months during pre-construction, followed by large spends on procurement. The next phase is the bulk of the construction, with that process finishing in month 24 resulting in a commercial online date in month 25. Ten-year CAPEX and O&M cash-flow estimations are provided for all locations in the accompanying spreadsheets. These also include ten-year trend tables for overnight CAPEX estimations.

Chart 4-1 EPC Cashflow



4.3 ASSUMPTIONS

All assumptions not stated thus far for solar PV cost estimates are provided below. Please see Appendix A for a full list of solar PV assumptions:

- Third party long-term service agreement O&M costs are included in the “asset management and security” line item.
- It is assumed that the 20 and 200 MW AC PV systems will take up a 160- and 1600-acre footprint, respectively. The land lease is assumed to be $55,000 and $547,000 yearly cost, respectively.
- Owner’s contingency (3%) and Builders Risk Insurance (0.317%) were developed from available literature and previous project history. These values represent the stability of the technology and thus vary for different technologies. PacifiCorp should review these values and update them as necessary.
- State tax assumptions were provided by PacifiCorp and implemented based on available literature. Pollution control values were omitted as the applicability of the tax is hard to define and is heavily location dependent. Owner should assess this tax separately for each location.
- WSP retained fewer OEM quotes than expected, and although the available ones fit with the report outputs, Owner should engage in vendor outreach for more detailed EPC values and delivery times.

5 WIND

5.1 ON-SHORE

5.1.1 GENERAL DISCRIPTION

The purpose of wind turbines is to convert the kinetic energy in the wind to rotational motion of the turbine itself. The rotary motion is then converted to electrical power that can be distributed across the grid. Wind turbine technology in its modern form is a mature technology, with over 50 years of research and operation behind it. Modern wind turbine designs are classified into two unique sub-sets:

1. Horizontal-axis wind turbines, which operate with the axis of rotation parallel to the prevailing wind direction.
2. Vertical-axis wind turbines, which operate with the axis of rotation perpendicular to the prevailing wind direction.

Almost all utility scale wind turbines constructed today are horizontal-axis turbines. These turbines consist of four main components: rotor, drivetrain, nacelle, and tower. The rotor consists of the turbine blades and the hub on which the blades are mounted, which transfers rotational energy to the drive train. The drivetrain utilizes a gearbox and rotary shafts to transfer power to the electrical generator. The nacelle houses the drivetrain and all other electrical components at the top of the tower, while the tower supports the rotor and nacelle at the prescribed height of the turbine.

The power available to be extracted from the wind is a function of the cube of the wind speed. As a result, if the wind speed were to double the available power would increase by a factor of eight. However, the ability of the turbine to extract this power is directly corelated to the area swept by the rotor blades. Thus, the two most important factors when considering the output of a potential wind energy project are the wind speed at the location and the size of the turbine.

5.1.2 PERFORMANCE

The wind resource assessment and capacity factor analysis of five different onshore sites in Idaho, Oregon, Utah, Washington, and Wyoming are summarized in this section. Generic project locations were selected in the area specified by owner.

The NREL's publicly available wind data source is utilized to perform a desktop study to determine the relative availability of wind resources in each site. The wind resource data is extracted for three fiscal years at 100m height. The wind resource assessment is performed based on 1-hour wind data. WSP selected the GE 3.4-137 wind turbine for this analysis. The wind turbine specifications are presented in Table 1. The maximum tip height of this turbine is under 500 feet, which means there are less likely to be conflict with the Federal Aviation Administration (FAA) altitudes available for general aircraft. One generic power curve at standard atmospheric conditions for each of the sites was assumed for the GE3.4-137.

Table 1 Wind Turbine Specifications

Rated power	3400 kW
Rotor Diameter	137m
Hub Height	85m
Blade Length	67.2m
Maximum Tip Height	153.5m

The Annual Energy Production (AEP) was estimated for five different sites. The wind speed data is adjusted to the wind turbine hub height before the power production assessment. The equation below is used for estimating the wind speed at hub height:

$$V_h = V_d \left(\frac{H_h}{H_d}\right)^{\alpha}$$

Where V_h is the wind velocity at wind turbine hub height, V_d is the dataset wind speed value at 100m height, H_h is the wind turbine hub height, H_d is the height wind speed dataset (100m), and α is the wind shear factor. We assumed that the wind shear factor is 0.15 in this analysis.

Table 2 shows the summary of gross and net annual capacity factors for each site. The annual losses for each wind site were assumed as 15 percent, which is a common assumption for screening level estimates in the wind industry. This loss factor was applied to the gross capacity factor estimates to derive a net annual capacity factor for each potential site.

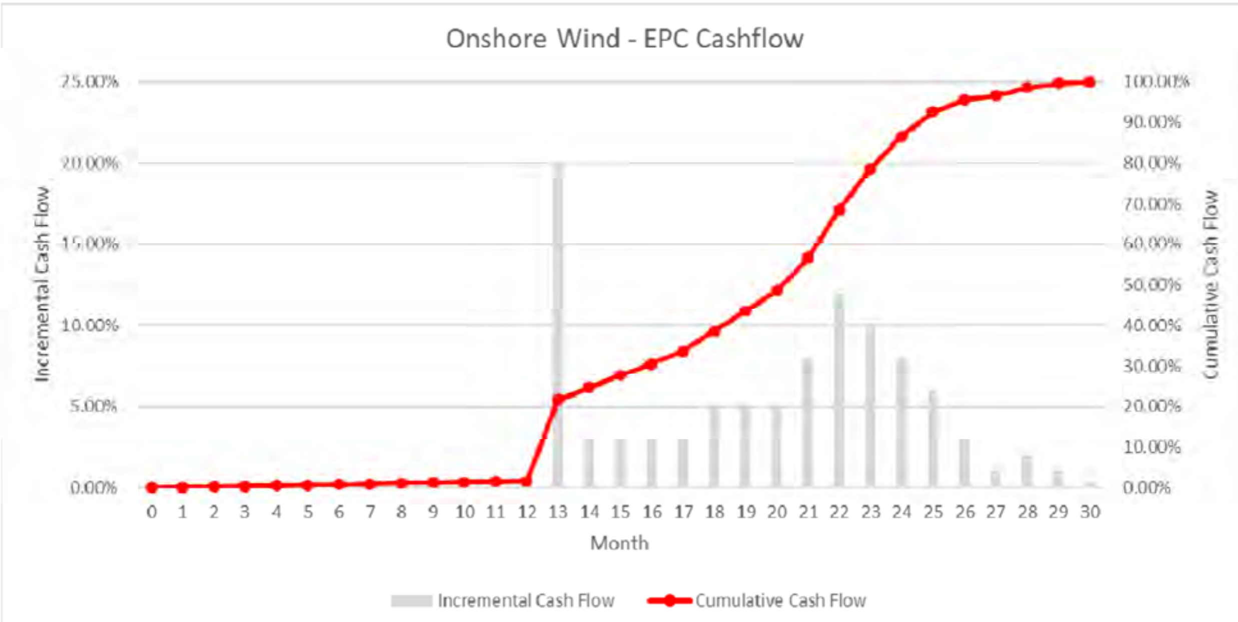
Table 2 Onshore Wind Annual Gross & Net Capacity

	GE 3.4 MW		
Location	Gross Annual Energy Production (GWh)	Net Annual Energy Production (GWh)	Net Capacity Factor
Pocatello, ID	8.841	7.515	25%
Arlington, OR	13.742	11.681	39%
Monticello, UT	13.952	11.859	40%
Goldendale, WA	10.745	9.133	31%
Medicine Bow, WY	17.175	14.599	49%

5.1.3 COST ESTIMATES

The Capital Expenditure (CAPEX) and Operation Expenditure (OPEX) estimations of each wind energy project is summarized in Appendix A. WSP referenced internal and public information to derive the cost estimates, and the CAPEX value ($/kw) aligns with the latest 2022 DoE land Based Wind Market report of ~$1,500/kw, which is 7-10% higher than the previous year due to inflation & supply chain constraints. The OPEX costs, were derived from the NREL 2022 ATB ($43/kw-yr.). Chart 51 below shows an estimation of EPC cashflows for onshore wind, with a slow start to spending during preconstruction and a large procurement guarantee followed by the majority of construction in months 14-30. It is assumed that the commercial online date would begin in month 31. The decommissioning costs are meant to represent the efforts to return the project site back to native conditions. This includes the decommissioning and demolition of all wind turbines as well as the associated infrastructure. Also included is the transportation cost associated with moving the turbines off-site to recycling or landfill locations. As shown in Chart 5-1, the decommissioning cost for 20MW wind farm is $1.19MM and for 200 MW wind facility costs $11.89MM to demolish the wind farm.

Chart 5-1 Onshore Wind EPC Cashflow



5.2 OFF-SHORE

5.2.1 GENERAL DISCRIPTION

Offshore regions of the United States boast some of the strongest and most consistent wind resources currently available. These higher average wind speeds offer a more consistent form of clean energy production than their onshore counterparts. To capture these resources wind turbines must be constructed in waters ranging from 50 to over 1000 feet (300m) in depth, which provides unique challenges. However, innovations in underwater foundation construction and transmission have made offshore wind a viable and attractive energy source.

5.2.2 PERFORMANCE

Like the onshore wind sites, the NREL's publicly available wind data is used for the wind resource assessment and power factor estimation of offshore wind facility. The site location is at West of Klamath River, CA, which was selected in the area specified by owner. WSP selected the GE 6-150 wind turbine for this analysis. The wind turbine specifications are presented in Table 3. A summary of the gross and net annual capacity factors of the offshore wind facility is presented in the Table 4.

Table 3 Wind Turbine Specifications

Rated power	6000 kW
Rotor Diameter	150m
Hub Height	100m
Blade Length	73.5m
Maximum Tip Height	173.5m

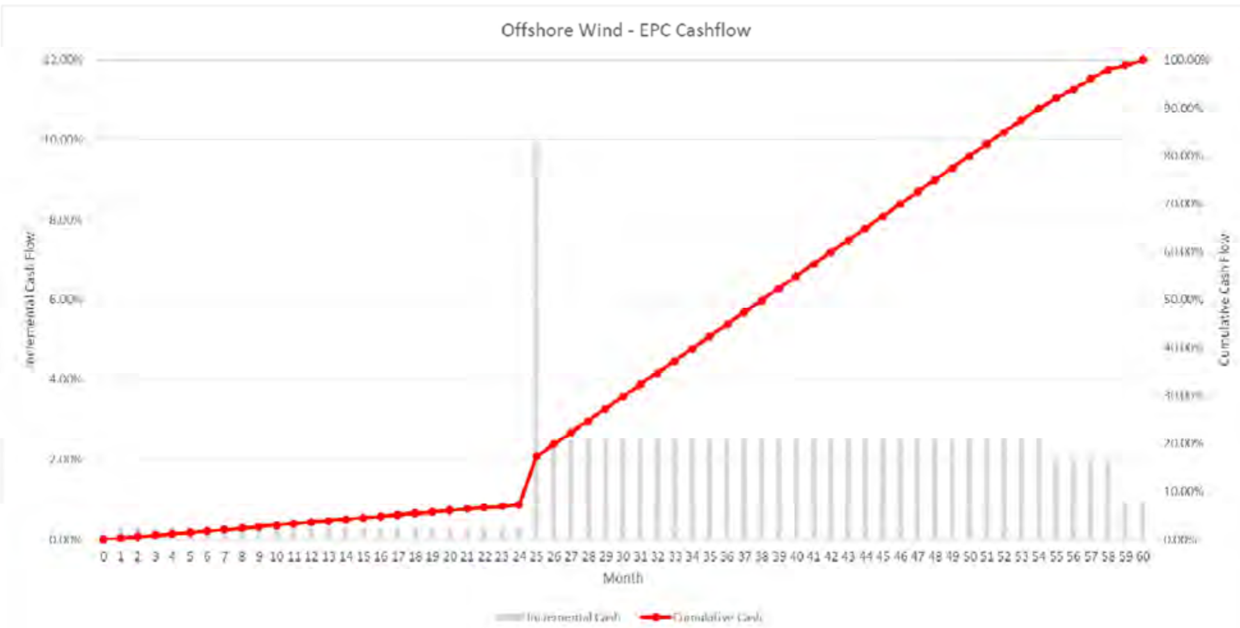
Table 4 Offshore Wind Annual Gross & Net Capacity

	GE 6.0 MW		
Location	Gross Annual Energy Production (GWh)	Net Annual Energy Production (GWh)	Net Capacity Factor
West of Klamath River, CA	29.002	24.652	47%

5.2.3 COST ESTIMATES

The cost estimation summary of CAPEX and OPEX of offshore wind site is shown in Appendix A. The entire cost estimation of offshore wind facility is referenced from NREL's 2022 IRP report for the cost of offshore wind in California and are assuming the Offshore wind farm is in the Humboldt Call Area. Similar to onshore wind, offshore wind sees a slow increase of cash flows in the first stages of the project. In this case, this phase lasts about two years. Then, there is the large procurement payment followed by three years of construction. It is assumed that the commercial online date is in month 61. The decommissioning cost without locational adjustment factor is $31.6MM for a 200 MW, and $158.23MM for a 1,000 MW offshore wind facility.

Chart 5-2 Offshore Wind EPC Cashflow



6 ENERGY STORAGE

Energy storage is a rapidly developing field with technologies at a different stage of maturity. While some are established and allow the development of relatively high-fidelity project budget estimates (e.g., Li-Ion battery), others are only undergoing initial commercial roll-out (e.g., gravity energy storage, compressed air energy storage) and therefore their cost and technical performance can be expected to significantly change over the next 5 years. Please see Appendix B for side-by-side comparison of the key technical parameters of the energy storage technologies included in this Report.

6.1 LITHIUM-ION

6.1.1 GENERAL DISCRIPTION

Aside from pumped hydro, Li-Ion battery energy storage is currently the most established and proven energy storage technology for grid-scale applications. This analysis is focused on systems utilizing LiFePO4 (LFP) battery chemistry, which have recently become dominating in this space. A relatively standardized set of technical parameters has been developed by utilities and there are many vendors offering substantially similar systems, allowing for robust competition. Regulatory compliance requirements are still evolving but generally well-understood by vendors and EPCs. Contractual technical support schemes such as Long-Term Service Agreements (LTSA) have been developed and implemented on numerous projects. A solid track of record of performance has been established both for the technology itself as well as for the leading OEMs. At the same time, recent supply chain challenges, relative scarcity of raw materials, shortages of manufacturing capacity and competition from the transportation sector with its rapidly increasing demand for Li-Ion cells and systems lead to increasingly long lead times for the Li-Ion battery systems and prevent the realization of the forecasted decrease in the per/kWh energy storage cost using this technology.

6.1.2 PERFORMANCE

Li-Ion based energy storage systems are well-suited for grid-tied systems designed for daily cycling including load shifting, demand response, peak shaving, and rapid response grid support applications such as voltage and frequency support. Li-Ion systems projected to last 15 to 20 years before decommissioning or re-powering projects. Due to calendar and cycle-driven capacity degradation they typically require several capacity augmentations events throughout their lifetime on order to maintain nameplate performance. Reference Appendix B for side-by-side comparison of the key technical parameters of Li-Ion battery systems with other energy storage technologies included in this Report. Below are EPC cash flow estimates for the battery equipment (storage block and power equipment) and the rest of the EPC line items. As shown, the equipment cash flow requires a high up-front payment, which has become more standard in recent years. The following payments make up the rest of the total cost, but many manufacturers require that early commitment to guarantee their product will be used. The EPC cash flow starts reasonably slow, and then has three spikes of large payments for the various other EPC inclusions. These cash flow estimates are for lithium-ion batteries and the percentages were provided by PacifiCorp, assuming a two-year project duration before the commercial online date in month 25.

Chart 6-1 Energy Storage - EPC Cashflow

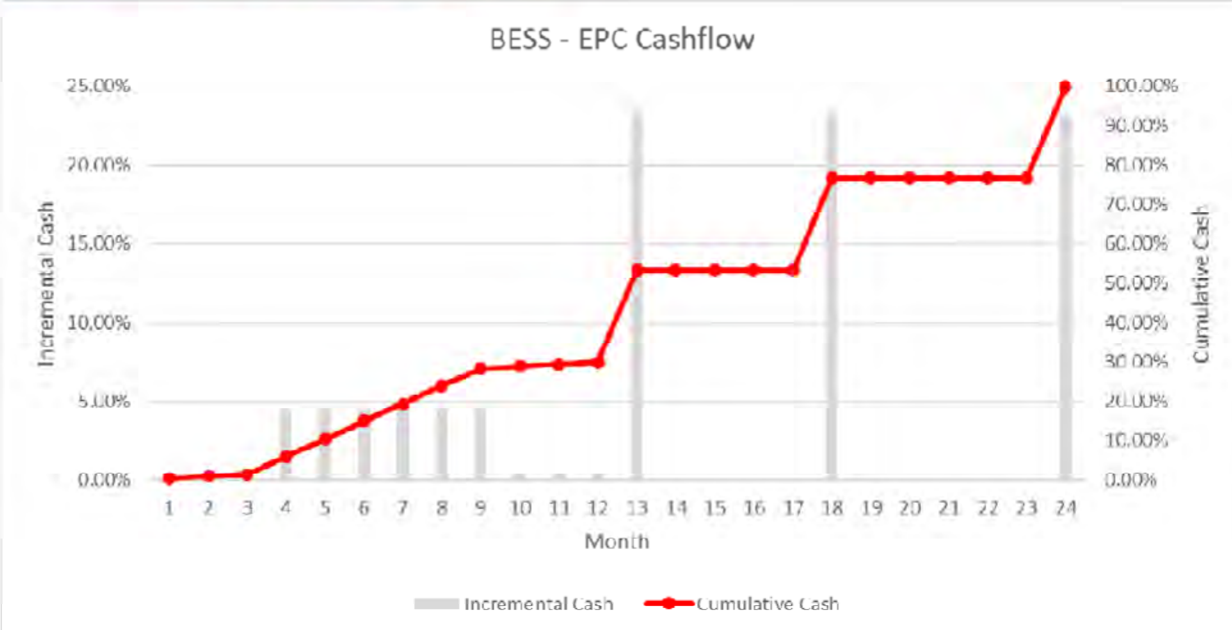


Chart 6-2 Energy Storage – Equipment Cashflow

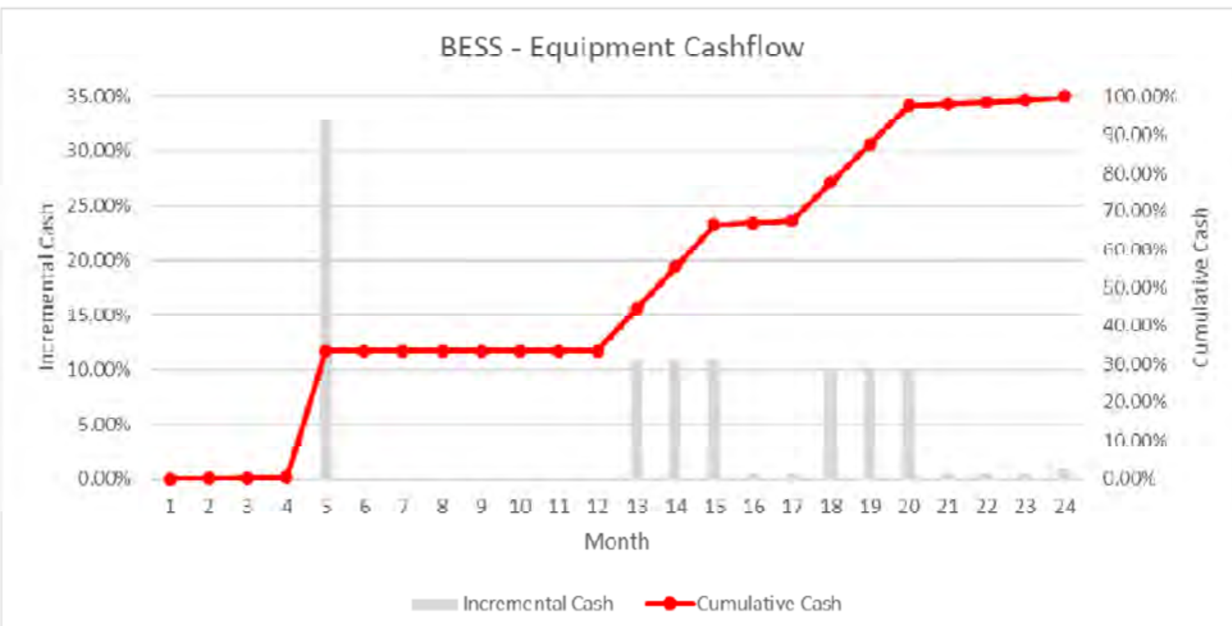


Chart 6-1 and 6-2: Cash-flow percentages derived from previous WSP and PAC projects, along with current industry standards. Equipment costs include the storage block and power equipment, EPC costs include all other EPC line items from the Energy Storage spreadsheet. Assuming project duration of 2 years.

6.2 FLOW BATTERY

6.2.1 GENERAL DISCRIPTION

Flow Batteries utilize electrolyte solution that changes its chemical state when flowing through a cell. This change is reversible and is accompanied with consumption or release of energy. Large volumes of electrolyte are stored in tanks designated for high and low energy states of the system (State of Charge). This technology allows a significant reduction of the cost of cells with their electrodes, easy upgrade or change of electrolyte without exchanging cells and changing electrodes without affecting electrolyte, limited capacity degradation that is also easier to manage and the resulting longer life span and lower lifetime costs as compared to Li-Ion batteries.

Flow batteries are relatively new technology with only few established OEMs and a limited number of full-scale commercial installations and limited track record. Several competing chemistries exist with significantly different technical parameters, with no clear leader established at time of writing this report. A standardized set of technical parameters has not yet been developed by utilities. Regulatory compliance requirements are still evolving and may not yet be fully well-understood by vendors and EPCs. Contractual technical support schemes such as Long-Term Service Agreements (LTSA) have been developed but have seen very limited implementation to date.

Lower projected lifetime costs as compared to Li-Ion, very linear performance through the entire state of charge (SoC) range, easy scalability, and the ability of flow battery systems to cost-effectively provide longer-duration energy storage (8-24 hrs.) position this technology as an emerging competition to Li-Ion-based systems.

6.2.2 PERFORMANCE

Flow energy storage systems are well-suited for grid-tied systems designed for daily (especially longer-duration) cycling including load shifting (especially for wind), short- and long-term demand response, peak shaving, and some grid support applications. Flow battery systems are projected to last between 12 and 50 years (depending on chemistry) before decommissioning or re-powering projects. They do not require capacity augmentation events (aside from electrolyte change) during their lifetime on order to maintain nameplate performance and do not have a lifetime cycle limit. Their response time and ramp rate are typically slower than Li-Ion batteries, and they do have a marked difference between “hot” and “cold” standby modes and the resulting response times. In some applications flow battery systems can provide significant advantages as compared to Li-Ion; however, a careful attention must be paid to key differences from Li-Ion and the resulting potential limitations for other applications. A project-level analysis of critical performance requirements is recommended prior to considering this technology. Please see Appendix B for side-by-side comparison of the key technical parameters of flow battery systems with other energy storage technologies included in this Report.

6.3 GRAVITY ENERGY STORAGE

6.3.1 GENERAL DISCRIPTION

Gravity energy storage is an emerging technology that uses the differential of potential energy of a body of a large mass (solid or liquid) depending on its elevation on the Earth’s gravity field as the means to store energy. This potential energy is converted into kinetic energy driving a generator to extract the stored energy (to discharge it). Conversely, kinetic energy of electric motors is used to increase the potential energy state of this system (to charge it). Technically, the well-established pumped hydro is a form of gravity storage. New systems being rolled out use solid weights (in elevated structures or in deep shafts), water in deep shafts, or a combination of the two (a solid piston creating water pressure).

Gravity energy storage is a new technology with only few established OEMs and a limited number of commercial pilot installations, and a very limited track record. At the same time, the basic physics behind these systems is very well understood and most of the required equipment is off-the-shelf industrial systems. This means that most of the risk lays in implementation rather that technology itself. A standardized set of technical parameters has not yet been developed by utilities; however, it can be easily modeled after pumped hydro. Regulatory compliance requirements are still evolving but are expected to fall within existing categories of heavy construction machinery. Contractual technical support schemes such as Long-Term Service Agreements (LTSA) have not yet been developed.

Advantages of gravity storage systems include extremely long lifespan low lifetime costs, very linear performance through the entire state of charge (SoC) range, easy scalability, and the ability to cost-effectively provide longer-duration energy storage (from days to weeks or months). If thought of in terms of this being a variation of pumped hydro, it should be relatively easy to assess applicability of this technology to specific project needs and develop a set of key technical parameters.

6.3.2 PERFORMANCE

Gravity energy storage systems are well-suited for grid-tied systems designed for daily (especially longer- and very long-duration) cycling including load shifting (especially for renewable generating resources with long-term variability such as wind), long-term demand response, peak shaving, and some grid support applications. Gravity systems are projected to last longer than 40 years before decommissioning or re-powering projects. They do not require capacity augmentation events during their lifetime on order to maintain nameplate performance and do not have a lifetime cycle limit. Their response time may be slower than Li-Ion batteries but like pumped hydro, a project-level analysis of critical performance requirements is recommended prior to considering this technology. Please see Appendix B for side-by-side comparison of the key technical parameters of gravity energy storage systems with other energy storage technologies included in this Report.

6.4 COMPRESSED AIR ENERGY STORAGE (CAES)

6.4.1 GENERAL DISCRIPTION

Compressed Air energy storage (CAES) is an emerging technology that uses large volumes of compressed air as the means of energy storage. To charge the system, electrically driven compressors fill a designated air storage container (such as underground cavern, underwater bladders, etc.) To discharge the system, the compressed air is routed to turboexpanders that drive electric generators. A recent variation of the technology is Adiabatic CAES (A-CAES) which recovers the heat produced during compressing the air into a thermal storage system; this energy is then used to reheat the air during expansion cycle, significantly improving system round-trip efficiency. The technology uses a lot of relatively standard turbomachinery based on gas turbine and industrial gas handling systems. One of the variations of A-CAES technology currently in the pilot stage uses CO_2 as a working fluid, enabling a theoretically higher system efficiency but requiring large storage for unpressurized CO_2.

CAES is a new technology with only few established OEMs and a limited number of commercial pilot installations, and a very limited track record. At the same time, the basic physics behind these systems is very well understood and most of the required equipment is based on standard industrial systems (with modifications). This means that the risk is divided between technology as such (mostly the air storage systems) and the implementation of packaging of turbomachinery and control systems. A standardized set of technical parameters has not yet been developed by utilities; however, requirements associated to simple cycle and CCGT power plants can be used as a basis. Regulatory compliance requirements are still evolving but are expected to fall within existing categories of industrial structures, mining, and turbomachinery. Contractual technical support schemes such as Long-Term Service Agreements (LTSA) have not yet been developed.

Advantages of CAES include long lifespan, low lifetime costs, the ability to cost-effectively provide longer-duration energy storage (from days to weeks or months).

6.4.2 PERFORMANCE

CAES systems are well-suited for grid-tied systems designed for daily (especially longer- and very long-duration) cycling including load shifting (especially for renewable generating resources with long-term variability such as wind), long-term demand response, peak shaving, and some grid support applications. CAES systems have projected lifespan of over 60 years (the longest projected lifespan among new technologies in PNNL reports) before decommissioning or re-powering projects. They do not require capacity augmentation events during their lifetime on order to maintain nameplate performance and do not have a lifetime cycle limit. Their response time may be slower than Li-Ion batteries but similar to a simple cycle (for CAES) or CCGT (for A-CAES) power plant. A project-level analysis of critical performance requirements is recommended prior to considering this technology. Reference Appendix B for side-by-side comparison of the key technical parameters of CAES systems with other energy storage technologies included in this report.

6.5 COST ESTIMATES

Table 5 Energy Storage CAPEX Costs

Capacity	Lithium-Ion Battery	Flow Battery	Gravity Energy Storage	Compressed Air Energy Storage
200 MW	338.55	458.19	657.74	350.60
500 MW	827.38	1,026.46	1,515.07	876.50
1000 MW	1,612.33	2,128.06	1,889.84	1753.00

Note: All values in MM$ and exclude taxes/locational adjustment factor.

Table 6 Energy Storage Expected Lifetime Costs

Technology	Lithium-Ion Battery			Flow Battery			Gravity Energy Storage			Compressed Air Energy Storage		
Capacity (MW)	200	500	1000	200	500	1000	200	500	1000	200	500	1000
Lifetime Costs (MM$)	554.75	1355.75	2642.00	547.12	1186.79	2389.63	1092.27	2418.75	3281.92	743.18	1779.75	3404.47
Annual Lifetime Costs (MM$/yr.)	27.74	67.79	132.10	21.88	47.47	95.59	21.85	48.36	65.64	12.39	29.66	56.74

Table 6 shows the expected lifetime costs of the various energy storage technologies. These calculations consider CAPEX values (Table 5) along with O&M values for the expected life of each technology. Inflation of 2.5% per year is included. The design life for lithium-ion, flow, gravity energy storage, and compressed air energy storage are 20, 25, 50, and 60 years, respectively.

6.6 EMERGING ENERGY STORAGE TECHNOLOGIES

Due to a current low maturity level for grid-scale storage, high predicted costs and (for some technologies) low round-trip efficiency in their current form, the below technologies were not yet considered for the cost analysis section of this Report. The discussion below is provided for reference and a potential inclusion into future versions of the IRP. As a technology nearing technical maturity for grid-scale energy storage, the Iron-Air energy storage is included in Appendix B.

6.6.1 GENERAL DISCRIPTION

IRON-AIR

The technology is based on the interaction of iron with oxygen. The oxygen necessary for the reaction is taken from the ambient air, eliminating the requirement for the cell to store it. The high energetic densities with 1,200 Wh/kg produced by metal-air batteries are attributed to these component savings. Compared with the usual lithium-ion that has 600 Wh/kg, iron-oxygen batteries store more energy on the weight basis. Ferrous electrodes are also theoretically extremely durable, capable of withstanding over 10,000 full cycles. Iron-oxygen batteries are also resilient to overcharging, overcurrent, and partial discharge. A rechargeable iron-oxygen battery can supply 100 hours of energy at operating cost compared to traditional power stations and less than a tenth of the price of lithium-ion batteries. On the downside, the round-trip efficiency is quite low for the current offering (~38%), which limits this technology for applications addressing extremely high-power generation curtailment rates. There is currently one vendor offering commercial-scale systems.

NAS THERMAL

Sodium Sulfur batteries operate at elevated temperatures of 300-350C. The active materials in a NaS battery are molten sulfur as the positive electrode and molten sodium as the negative. The electrodes are separated by a solid ceramic, sodium alumina, which also serves as the electrolyte. This ceramic allows only positively charged sodium-ions to pass through. During discharge electrons are stripped off the sodium metal (one negatively charged electron for every sodium atom) leading to formation of the sodium-ions that then move through the electrolyte to the positive electrode compartment. The electrons that are stripped off the sodium metal move through the circuit and then back into the battery at the positive electrode, where they are taken up by the molten sulfur to form polysulfide. The positively charged sodium-ions moving into the positive electrode compartment balance the electron charge flow. During charge this process is reversed. The battery must be kept hot (typically > 300 ºC) to facilitate the process (i.e., independent heaters are part of the battery system). In general, NaS cells are highly efficient (typically 89%). There is currently one vendor offering NaS systems, with 190 systems installed in Japan and fifteen in UAE, with the combined capacity of 378MW/2,268MWh. The systems appear to be most suitable to 6+ hrs. duration storage.

ULTRACAPACITORS

Electrochemical capacitors (ECs) – sometimes referred to as “electric double-layer” capacitors, “Supercapacitor” or “Ultracapacitor” – provide a compelling set of characteristics – high energy density, extremely high cycle life, extremely fast response time. ECs have specific energy values that approach 206Wh/kg and up to 496W/kg power density. Because of their high power, long cycle life, good reliability, and other characteristics, the market and applications for ECs have been steadily increasing. There are dozens of manufacturers, and more are entering the market because of market growth. Aqueous electrolyte asymmetric EC technology offers opportunities to achieve exceptionally low-cost bulk energy storage. There are difference requirements for energy storage in different electricity grid-related applications from voltage support and load following to integration of wind generation and time-shifting. Symmetric ECs have response times on the order of 1 second and are well-suited for short duration high-power applications related to both grid regulation and frequency regulation. Asymmetric ECs are better suited for grid energy storage applications that have long duration, for instance, charge-at-night/use-during-the-day storage (i.e., bulk energy storage). Some asymmetric EC products have been optimized for ~5-hour charge with ~5-hour discharge. Advantages of ECs in these applications include long cycle life, good efficiency, low life-cycle costs, and adequate energy density.

7 CO-LOCATED PLANTS

7.1 GENERAL DESCRIPTION

WSP was tasked with analyzing three separate colocation scenarios, including Solar + Energy Storage, Wind + Energy Storage, and Wind + Solar + Energy Storage. All cost information (Capex and O&M) can be found in Appendix A. The colocation analysis was conducted by adding the separate scenarios, with a few tweaks, as discussed below.

7.2 SOLAR + ENERGY STORAGE

The solar plus energy storage models combine the 200 MW AC PV systems with a 200 MW Li-Ion battery by co-locating the projects together. It is assumed that the battery is AC coupled with the PV system. This layout requires a separate inverter for both the PV system and the battery, as was modeled in the separate PV and battery scenarios. There are benefits and constrains to the AC coupling method including cost and PV curtailment. WSP suggests that Owner conduct further analysis on DC and AC coupling to better understand what is needed for a given PV and energy storage scenario. One of the benefits of co-locating the two technologies together are cost reductions. NREL's "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks: Q1 2021" states that co-located PV and Energy Storage plants see a 6-7% total cost reduction through cost savings resulting from site preparation; land acquisition; permitting and interconnection; installation; labor; hardware (via sharing of hardware such as switchgears, transformers, and controls); overhead; and profit.

The PV and energy storage spreadsheet was developed by combining the two separate scenarios into one. The only change aside from the 6% co-location cost reduction was the ability to use the DoE/EIA location adjustment factor for the Li-Ion battery now that there was a specific location tied to the energy storage system. This allowed for a more defined estimate of both capital and operational cost estimates for the battery. It should be noted that the addition of energy storage to a renewable energy plant can greatly increase the profit of the plant. Although the location plays a major factor, NREL's "Influence of Hybridization on the Capacity Value of PV and Battery Resources" discusses the economic benefit that could come from co-location. These intricacies were outside of the scope of this project but should be investigated by Owner to fully understand the economics of co-location.

7.3 WIND + ENERGY STORAGE

Similar to the PV and energy storage section above, there are assumed cost savings from pairing wind and energy storage. Although there is not a specific cost reduction factor published by a major national laboratory, WSP is confident that similar colocation savings would be present within a wind and energy storage combined power plant. Thus, the 6% cost reduction was also applied to these scenarios. Similar to Solar + Energy Storage, the battery costs were scaled by the DoE/EIA location adjustment factor given the location of the project.

7.4 WIND + SOLAR + ENERGY STORAGE

As stated above, there is an expected 6% colocation savings when energy storage is paired with a wind or solar plant. Additionally, NREL's "Potential Infrastructure Cost Savings at Hybrid Wind Plus Solar PV Plants" describes how the colocation of Wind + Solar can see cost savings of at least 7%. The report adds that, depending on the capacities of each, these savings can be much higher. Even though Owner could expect savings higher than 7% for a Wind + Solar + Energy Storage plant, the estimates provided contain a conservative margin of 7%.

8 CONCLUSION

This technology assessment is intended to provide PacifiCorp with greater insight into the associated costs of various renewable energy systems. The purpose of the document, and its accompanying spreadsheets, is to assist in the planning efforts regarding PacifiCorp's upcoming 2023 IRP. It should be noted again that this work has been done at a screening level and should be investigated further for any future project development.

Although recent inflation and tariffs have impeded the reduction in implementing renewable energy technologies, there is still a strong confidence that most, if not all, of the referenced technologies will continue to see cost declines over the next decade. Solar PV and onshore wind are proven to be cost-effective, and thus have lower associated risk. Offshore wind, although not heavily deployed in the United States, shows extreme potential—especially in PacifiCorp territory. This assessment investigated various energy storage technologies, each with different benefits and drawbacks. The ability to co-locate solar PV and wind with energy storage (and each other) can result in reduced EPC costs and incur even more cost savings throughout the project lifetime.

This assessment is intended to highlight high-level cost information, and not to provide a recommendation. Different technologies have various use cases, especially regarding a large utility that incorporates all kinds of grid services within their day-to-day work operations. The WSP Team has provided the conclusion of our research to assist with these specific operational decisions.

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APPENDIX

A - TECHNOLOGY COST ASSESSMENT

Appendix A

A - 1 Geothermal

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE GEOTHERMAL		
PROJECT TYPE		
PROJECT LOCATION (Note 1)	**Dual Flash Expansion of Blundell Plant**	**Greenfield Binary Plant**
BASE PLANT DESCRIPTION	**200 MW**	**200 MW**
Reservoir Temperature (deg C)	245	245
Enthalpy (kJ/kg)	1,066	1,066
MW Generated per Blundell Well (MW/well)	7.7	6.7
# Production Wells Required	27	31
Total Flow (kg/s)	1,926	2,221
Drilling Failure Rate (%)	20%	20%
Production Wells Drilled	33	38
Reinjection Ratio (Production Flow/Reinjection Flow)	0.77	0.77
# Reinjection Wells Required	22	25
Reinjection Wells Drilled	27	30
Average Well Decline (%/yr)	3%	3%
Plant Capacity Factor (%)	95%	95%
ESTIMATED CAPITAL AND O&M COSTS		
EPC Costs, 2022 $MM	**$689**	**$1,000**
Drilling (Note 2)	$264.34	$304.3
Steam field Development	$105.69	$90.3
Power Plant	$310.26	$503.7
Interconnection	$8.24	$8.2
Owner's Costs Without Contingency, 2022 $MM	**$36**	**$47**
Engineering & PM	$26.62	$33.8
Legal Cost	$4.68	$6.8
Land Cost	$0.56	$0.6
Permitting	$0.19	$0.2
Geoscience & Environmental Assessments	$0.47	$0.5
Well Testing	$0.47	$0.5
Assessment Infrastructure	$2.58	$4.4
Feasibility Reports	$0.19	$0.2
Subtotal - Capital Cost, 2022 $MM	**$724**	**$1,047**
Owner's Contingency (5%)	$36.2	$52.4
State Taxes (Utah)	$47.2	$68.5
Total CAPEX, 2022 $MM	**$807.66**	**$1,167.99**
Total Screening Level Project Costs, 2022 $/kW	**$4,038**	**$5,840**
Demolition Costs (end of life cycle) 2022 $MM	**$23.40**	**$23.40**
O&M Cost, 2022 $MM/yr	**$23.0**	**$23.0**
O&M Cost, 2022 $/kW-yr	115.0	$115.0
Notes Note 1: Greenfield Binary Plant location assumed in same geographic area as the Blundell Plant Note 2: Assumed drilling depths 2500m for production wells & 2000m for reinjection wells		

A - 2 PV Solar

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
SOLAR GENERATION

PROJECT TYPE						
PROJECT LOCATION	Idaho Falls, ID		Lakeview, OR		Milford, UT	
BASE PLANT DESCRIPTION	20 MW	200 MW	20 MW	200 MW	20 MW	200 MW
Nominal Output, MWac	20	200	20	200	20	200
Nominal Output, MWdc	26	260	26	260	26	260
Annualized Energy Production, MWh (Yr 1)	45,676	456,760	48,355	483,552	52,910	529,104
AC Capacity Factor at POI (%) (Note 1)	26.1%	26.1%	27.6%	27.6%	30.2%	30.2%
Availability Factor, % (Note 2)	99%	99%	99%	99%	99%	99%
Assumed Land Use, Acres (Note 2)	160	1600	160	1600	160	1600
PV Inverter Loading Ratio (DC/AC)	1.30	1.30	1.30	1.30	1.30	1.30
PV Degradation, %/yr (Note 2)	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2	2	2
ESTIMATED PERFORMANCE						
Base Load Performance @ (Annual Average) Net Plant Output, kW	20,000	200,000	20,000	200,000	20,000	200,000
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$17.1**	**$140.8**	**$17.1**	**$140.8**	**$17.1**	**$140.8**
Modules	$6.7	$66.8	$6.7	$66.8	$6.7	$66.8
Inverter	$1.0	$8.0	$1.0	$8.0	$1.0	$8.0
Structural BOS	$2.4	$20.0	$2.4	$20.0	$2.4	$20.0
Electrical BOS	$2.4	$10.0	$2.4	$10.0	$2.4	$10.0
Installer OH (Labor Costs)	$2.2	$20.0	$2.2	$20.0	$2.2	$20.0
EPC OH (Equipment and Material)	$1.6	$10.0	$1.6	$10.0	$1.6	$10.0
EPC Markup	$0.8	$6.0	$0.8	$6.0	$0.8	$6.0
Owner's Costs, 2022 MM$	**$3.0**	**$24.0**	**$3.0**	**$24.0**	**$3.0**	**$24.0**
Engineering & Development OH	$1.0	$4.0	$1.0	$4.0	$1.0	$4.0
Transmission Line	$0.20	$2.0	$0.20	$2.0	$0.20	$2.0
PII (permitting fee, interconnection, commissioning)	$0.8	$8.0	$0.8	$8.0	$0.8	$8.0
Land Acquisition (Note 3)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Owner's Project Development	$1.0	$10.0	$1.0	$10.0	$1.0	$10.0
Owner's Project Management	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Owner's Legal Costs	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Contingency and Insurance, 2022 MM$	**$0.7**	**$5.5**	**$0.7**	**$5.5**	**$0.7**	**$5.5**
Owner's Contingency (3%) (Note 4)	$0.6	$4.9	$0.6	$4.9	$0.6	$4.9
Builders Risk Insurance (.317%) (Note 4)	$0.1	$0.5	$0.1	$0.5	$0.1	$0.5
Total Screening Level Project Costs, 2022 MM$	**$20.7**	**$170.3**	**$20.7**	**$170.3**	**$20.7**	**$170.3**
State Taxes (Note 4)	**$1.0**	**$8.4**	**$0.0**	**$0.0**	**$1.2**	**$9.5**
Balance of Plant Materials and Products	$0.89	$7.25	0	$0.0	$1.02	$8.27
Labor and Services	$0.13	$1.20	0	$0.0	$0.1	$1.2
CAPEX, 2022 MM$	**$21.77**	**$178.71**	**$20.75**	**$170.27**	**$21.90**	**$179.74**
Location Adjusted CAPEX 2022 MM$	**$21.34**	**$175.14**	**$21.78**	**$178.78**	**$21.24**	**$174.35**
Total Screening Level Project Costs, 2022 $/kWdc	**$1,066.77**	**$875.70**	**$1,089.17**	**$893.90**	**$1,096.18**	**$825.79**
Total Screening Level Project Costs, 2022 $/kWac	**$1,386.80**	**$1,138.41**	**$1,415.92**	**$1,162.07**	**$1,308.04**	**$1,073.53**
Demolition Costs (end of life cycle) 2022 MM$ (Note 5)	**$0.59**	**$5.88**	**$0.63**	**$6.30**	**$0.58**	**$5.82**
O&M Cost, 2023 MM$/yr (Note 6)	**$0.4**	**$4.2**	**$0.4**	**$4.2**	**$0.4**	**$4.2**
Module cleaning	$0.043	$0.433	$0.043	$0.433	$0.043	$0.433
Vegetation and/or Pest Management	$0.016	$0.158	$0.016	$0.158	$0.016	$0.158
System inspection and monitoring	$0.045	$0.449	$0.045	$0.449	$0.045	$0.449
Component parts replacement	$0.033	$0.327	$0.033	$0.327	$0.033	$0.327
Module replacement	$0.007	$0.075	$0.007	$0.075	$0.007	$0.075
Inverter replacement	$0.078	$0.779	$0.078	$0.779	$0.078	$0.779
Land Lease	$0.055	$0.547	$0.055	$0.547	$0.055	$0.547
Property tax	$0.043	$0.433	$0.043	$0.433	$0.043	$0.433
Insurance	$0.051	$0.507	$0.051	$0.507	$0.051	$0.507
Asset management and security (Note 6)	$0.041	$0.410	$0.041	$0.410	$0.041	$0.410
Operations administration	$0.006	$0.057	$0.006	$0.057	$0.006	$0.057
O&M Cost, 2023 $/kWac-yr	**$20.87**	**$20.87**	**$20.87**	**$20.87**	**$20.87**	**$20.87**

Notes

Note 1. Solar capacity factor supplied by PAC.
Note 2. Base plant descriptions provided by PAC.
Note 3. Land is assumed to be leased throughout the project lifetime and is thus included in yearly O&M values.
Note 4. State Tax rates provided by PAC.
Note 5. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.
Note 6. Third party long-term service agreement costs are included in the asset management and security line item.

A - 3 PV Solar (Cont.)

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TAB SOLAR GENERATION				
PROJECT TYPE				
PROJECT LOCATION	Rock Springs, WY		Yakima, WA	
BASE PLANT DESCRIPTION	**20 MW**	**200 MW**	**20 MW**	**200 MW**
Nominal Output, MWac	20	200	20	200
Nominal Output, MWdc	26	260	26	260
Annualized Energy Production, MWh (Yr 1)	48,944	489,439	42,369	423,694
AC Capacity Factor at POI (%) (Note 1)	27.9%	27.9%	24.2%	24.2%
Availability Factor, % (Note 2)	99%	99%	99%	99%
Assumed Land Use, Acres (Note 2)	160	1600	160	1600
PV Inverter Loading Ratio (DC/AC)	1.30	1.30	1.30	1.30
PV Degradation, %/yr (Note 2)	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2
ESTIMATED PERFORMANCE				
Base Load Performance @ (Annual Average)				
Net Plant Output, kW	20,000	200,000	20,000	200,000
ESTIMATED CAPITAL AND O&M COSTS				
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$17.1**	**$140.8**	**$17.1**	**$140.8**
Modules	$6.7	$66.8	$6.7	$66.8
Inverter	$1.0	$8.0	$1.0	$8.0
Structural BOS	$2.4	$20.0	$2.4	$20.0
Electrical BOS	$2.4	$10.0	$2.4	$10.0
Installer OH (Labor Costs)	$2.2	$20.0	$2.2	$20.0
EPC OH (Equipment and Material)	$1.6	$10.0	$1.6	$10.0
EPC Markup	$0.8	$6.0	$0.8	$6.0
Owner's Costs, 2022 MM$	**$3.0**	**$24.0**	**$3.0**	**$24.0**
Engineering & Development OH	$1.0	$4.0	$1.0	$4.0
Transmission Line	$0.20	$2.0	$0.20	$2.0
PII (permitting fee, interconnection, commissioning)	$0.8	$8.0	$0.8	$8.0
Land Acquisition (Note 3)	$0.0	$0.0	$0.0	$0.0
Owner's Project Development	$1.0	$10.0	$1.0	$10.0
Owner's Project Management	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Owner's Legal Costs	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Contingency and Insurance, 2022 MM$	**$0.7**	**$5.5**	**$0.7**	**$5.5**
Owner's Contingency (3%) (Note 4)	$0.6	$4.9	$0.6	$4.9
Builders Risk Insurance (.317%) (Note 4)	$0.1	$0.5	$0.1	$0.5
Total Screening Level Project Costs, 2022 MM$	**$20.7**	**$170.3**	**$20.7**	**$170.3**
State Taxes (Note 4)	**$0.8**	**$6.4**	**$1.5**	**$12.3**
Balance of Plant Materials and Products	$0.79	$6.44	$1.30	$10.57
Labor and Services	0	0	$0.19	$1.75
CAPEX, 2022 MM$	**$21.54**	**$176.71**	**$22.24**	**$182.59**
Location Adjusted CAPEX 2022 MM$	**$21.75**	**$178.47**	**$22.91**	**$188.07**
Total Screening Level Project Costs, 2022 $/kWdc	**$1,047.68**	**$859.85**	**$1,068.42**	**$876.87**
Total Screening Level Project Costs, 2022 $/kWac	**$1,361.98**	**$1,117.80**	**$1,388.95**	**$1,139.93**
Demolition Costs (end of life cycle) 2022 MM$ (Note 5)	**$0.61**	**$6.06**	**$0.62**	**$6.18**
O&M Cost, 2020 MM$/yr (Note 6)	**$0.4**	**$4.2**	**$0.4**	**$4.2**
Module cleaning	$0.043	$0.433	$0.043	$0.433
Vegetation and/or Pest Management	$0.016	$0.158	$0.016	$0.158
System inspection and monitoring	$0.045	$0.449	$0.045	$0.449
Component parts replacement	$0.033	$0.327	$0.033	$0.327
Module replacement	$0.007	$0.075	$0.007	$0.075
Inverter replacement	$0.078	$0.779	$0.078	$0.779
Land Lease	$0.055	$0.547	$0.055	$0.547
Property tax	$0.043	$0.433	$0.043	$0.433
Insurance	$0.051	$0.507	$0.051	$0.507
Asset management and security (Note 6)	$0.041	$0.410	$0.041	$0.410
Operations administration	$0.006	$0.057	$0.006	$0.057
O&M Cost, 2020 $/kWac-yr	**$20.87**	**$20.87**	**$20.87**	**$20.87**

Notes
Note 1. Solar capacity factor supplied by PAC.
Note 2. Base plant descriptions provided by PAC.
Note 3. Land is assumed to be leased throughout the project lifetime and is thus included in yearly O&M values.
Note 4. State Tax rates provided by PAC.
Note 5. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.
Note 6. Third party long-term service agreement costs are included in the asset management and security line item.

A - 4 ONSHORE WIND

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE WIND GENERATION										
PROJECT TYPE	Onshore Wind									
PROJECT LOCATION	Pocatello, ID		Arlington, OR		Monticello, UT		Medicine Bow, WY		Goldendale, WA	
BASE PLANT DESCRIPTION	20 MW	200 MW	20 MW	200 MW	20 MW	200 MW	20 MW	200 MW	20 MW	200 MW
ESTIMATED CAPITAL AND O&M COSTS										
BOP Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$34.79**	**$263.1**	**$34.79**	**$263.1**	**$34.79**	**$263.1**	**$34.79**	**$263.1**	**$34.79**	**$263.1**
Wind Turbine Generators	$17.50	$175.00	$17.50	$175.00	$17.50	$175.00	$17.50	$175.00	$17.50	$175.00
Met Mast	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05	$1.05
Foundations	$1.42	$14.19	$1.42	$14.19	$1.42	$14.19	$1.42	$14.19	$1.42	$14.19
Assembly & Installation	$0.86	$8.57	$0.86	$8.57	$0.86	$8.57	$0.86	$8.57	$0.86	$8.57
Roads & Crane Pads	$0.95	$9.49	$0.95	$9.49	$0.95	$9.49	$0.95	$9.49	$0.95	$9.49
O&M Building	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1	$1.1
Collection System	$1.2	$12.2	$1.2	$12.2	$1.2	$12.2	$1.2	$12.2	$1.2	$12.2
SCADA	$0.2	$0.4	$0.2	$0.4	$0.2	$0.4	$0.2	$0.4	$0.2	$0.4
Switchgear/Substation (Note 2 & 3)	$5.1	$15.9	$5.1	$15.9	$5.1	$15.9	$5.1	$15.9	$5.1	$15.9
Step-Up Transformer & Interconnection (Note 4)	$1.97	$4.92	$1.97	$4.92	$1.97	$4.92	$1.97	$4.92	$1.97	$4.92
Aircraft Detection Lighting System	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EPC Fee (8%)	$2.58	$19.49	$2.58	$19.49	$2.58	$19.49	$2.58	$19.49	$2.58	$19.49
Owner's Costs Without Contingency, 2022 $MM	**$1.2**	**$5.5**	**$1.8**	**$6.2**	**$1.2**	**$5.5**	**$1.5**	**$5.9**	**$1.9**	**$6.4**
Project Design	$0.2	$2.0	$0.2	$2.0	$0.2	$2.0	$0.2	$2.0	$0.2	$2.0
Owner's Engineer	$0.05	$0.17	$0.05	$0.17	$0.05	$0.17	$0.05	$0.17	$0.05	$0.17
Land Lease & Development	$0.2	$2.4	$0.2	$2.4	$0.2	$2.4	$0.2	$2.4	$0.2	$2.4
Permitting (Note 5)	$0.5	$0.6	$1.1	$1.4	$0.5	$0.6	$0.9	$1.1	$1.3	$1.6
Wildlife Studies	$0.1	$0.2	$0.1	$0.2	$0.1	$0.2	$0.1	$0.2	$0.1	$0.2
Eagle Take Permits	$0.07	$0.09	$0.07	$0.09	$0.07	$0.09	$0.07	$0.09	$0.07	$0.09
Capital Spares	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M
Subtotal - Capital Costs, 2022 $MM	**$36.0**	**$268.6**	**$36.6**	**$269.3**	**$36.0**	**$268.6**	**$36.3**	**$269.0**	**$36.7**	**$269.5**
Owner's Contingency (5% of Capital Cost)	$1.8	$13.4	$1.8	$13.5	$1.8	$13.4	$1.8	$13.5	$1.8	$13.5
Total - Costs With Contingency, 2022 $MM	**$37.8**	**$282.0**	**$38.4**	**$282.8**	**$37.8**	**$282.0**	**$38.1**	**$282.5**	**$38.5**	**$283.0**
State Taxes, $MM (Note 6)	**$2.0**	**$14.7**	**$0.0**	**$0.0**	**$1.7**	**$14.3**	**$1.8**	**$14.7**	**$2.9**	**$21.5**
Balance of Plant Materials and Products	$1.5	$12.5	NA	NA	$1.7	$14.3	$1.3	$12.5	$2.1	$18.3
Labor and Services	$0.5	$2.2	NA	NA	NA	NA	$0.5	$2.2	$0.8	$3.2
CAPEX, 2022 $MM	**$39.73**	**$296.73**	**$38.37**	**$282.79**	**$39.42**	**$296.32**	**$39.93**	**$297.19**	**$41.42**	**$304.46**
Location Adjusted CAPEX 2022 $MM	**$40.13**	**$299.70**	**$39.91**	**$294.10**	**$40.60**	**$305.21**	**$39.53**	**$294.21**	**$42.25**	**$310.55**
Total Screening Level Project Costs, 2022 $/kW	**$2,006.56**	**$1,498.51**	**$1,995.44**	**$1,470.50**	**$2,030.00**	**$1,526.07**	**$1,976.66**	**$1,471.07**	**$2,112.46**	**$1,552.76**
Demolition Costs (end of life cycle) 2022 $MM (Note 6)	**$1.19**	**$11.89**	**$1.19**	**$11.89**	**$1.19**	**$11.89**	**$1.19**	**$11.89**	**$1.19**	**$11.89**
O&M Cost, 2022 $MM/yr	**$0.9**	**$8.6**	**$0.9**	**$8.6**	**$0.9**	**$8.6**	**$0.9**	**$8.6**	**$0.9**	**$8.6**
O&M Cost, 2022 $/kW-yr	$43.0	$43.0	$43.0	$43.0	$43.0	$43.0	$43.0	$43.0	$43.0	$43.0

Notes

Note 1. 20 MW Substation assumes: Tie in 230kV line through three disconnects, a single 230kV breaker connection, & a 1200A, 34.5kV GIS switchgear housed in a building

Note 2. 200 MW Substation assumes: Three breaker ring 230kV AIS switchgear & (2) 2500A, 34.5kV GIS switchgear housed in a building

Note 3. 20 MW Plant assumes (1) 30 MVA (230 kV/34.5 kV) transformer & 200 MW Plant assumes (2) 125 MVA (230 kV/34.5 kV) transformer. 1 one mile interconnection tie line is assumed for both cases.

Note 4. Permitting cost assumes the permitting matrix from the 2022 PacifiCorp All-Source RFP is utilized

Note 5. State Tax information provided by PacifiCorp

Note 6. Reclamation costs included in Demolition costs. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.

A - 5 OFFSHORE WIND

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE WIND GENERATION		
PROJECT TYPE	**Offshore Wind**	
PROJECT LOCATION	**Northern, CA**	
BASE PLANT DESCRIPTION	**200 MW**	**1,000 MW**
ESTIMATED CAPITAL AND O&M COSTS (Note 1)		
BOP Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$673.7**	**$3,368.4**
Wind Turbine Generators	$224.84	1124.22
Substructure	$213.93	1069.66
Port, Staging, Logistics, & Fixed Costs	$7.62	38.11
Turbine Install	$25.46	127.32
Substructure Install	$13.34	66.69
Array Cabling	$47.6	238.18
Export Cable	$77.4	387.16
Onshore Spur Line	$13.5	67.56
EPC Fee (8%)	$49.90	249.51
Owner's Costs Without Contingency, 2022 $MM	**$67.4**	**$336.9**
Development	$24.1	120.39
Lease Price	$15.24	76.22
Project Management	$12.5	62.36
Insurance during Construction	$7.8	38.98
Project Completion	$7.8	38.98
Subtotal - Capital Costs, 2022 $MM	**$741.1**	**$3,705.3**
Procurement Contingency	$36.6	182.75
Installation Contingency	$13.5	67.56
Total - Owner's Costs With Contingency, 2022 $MM	**$791.1**	**$3,955.6**
CAPEX, 2022 $MM	**$791.13**	**$3,955.63**
Total Screening Level Project Costs, 2022 $/kW	**$3,955.63**	**$3,955.63**
Demolition Costs (end of life cycle) 2022 $MM	**$31.65**	**$158.23**
O&M Cost, 2022 $MM/yr	**$20.6**	**$103.0**
O&M Cost, 2022 $/kW-yr	$103.0	$103.0
Notes Note 1. Capital Costs are over-night & don't include financing costs		

A - 6

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE WIND GENERATION		
PROJECT TYPE	Offshore Wind	
PROJECT LOCATION	Northern, CA	
BASE PLANT DESCRIPTION	200 MW	1,000 MW
ESTIMATED CAPITAL AND O&M COSTS (Note 1)		
BOP Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$673.7**	**$3,368.4**
Wind Turbine Generators	$224.84	1124.22
Substructure	$213.93	1069.66
Port, Staging, Logistics, & Fixed Costs	$7.62	38.11
Turbine Install	$25.46	127.32
Substructure Install	$13.34	66.69
Array Cabling	$47.6	238.18
Export Cable	$77.4	387.16
Onshore Spur Line	$13.5	67.56
EPC Fee (8%)	$49.90	249.51
Owner's Costs Without Contingency, 2022 $MM	**$67.4**	**$336.9**
Development	$24.1	120.39
Lease Price	$15.24	76.22
Project Management	$12.5	62.36
Insurance during Construction	$7.8	38.98
Project Completion	$7.8	38.98
Subtotal - Capital Costs, 2022 $MM	**$741.1**	**$3,705.3**
Procurement Contingency	$36.6	182.75
Installation Contingency	$13.5	67.56
Total - Owner's Costs With Contingency, 2022 $MM	**$791.1**	**$3,955.6**
CAPEX, 2022 $MM	**$791.13**	**$3,955.63**
Total Screening Level Project Costs, 2022 $/kW	**$3,955.63**	**$3,955.63**
Demolition Costs (end of life cycle) 2022 $MM	**$31.65**	**$158.23**
O&M Cost, 2022 $MM/yr	**$20.6**	**$103.0**
O&M Cost, 2022 $/kW-yr	$103.0	$103.0
Notes		
Note 1. Capital Costs are over-night & don't include financing costs		

A - 7 Energy Storage: Li-Ion

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE BESS GENERATION			
TECHNOLOGY	**Lithium-ion batteries (Li-Ion)**		
BASE PLANT DESCRIPTION, MW	**200**	**500**	**1000**
Net Plant Output kW	200,000	500,000	1,000,000
Capacity, hours	4	4	4
Design Life (Assuming 365 Cycles per Year)	20	20	20
Round Trip Efficiency (AC AC)	83%	83%	83%
Estimated Annual Throughput (MWh) (80% Max Discharge)	59,096	147,740	295,480
kWh	800,000	2,000,000	4,000,000
ESTIMATED CAPITAL AND O&M COSTS (Note 7)			
Storage Block (Note 1)	$132.00	$321.62	$630.64
Storage BOS (Note 2)	$30.40	$74.75	$146.60
Power Equipment (Note 3)	$12.60	$28.55	$54.40
Controls & Communication (Note 4)	$0.30	$0.58	$1.12
System Integration (Note 5)	$34.40	$85.56	$167.80
Engineering, Procurement & Construction (Note 6)	$41.60	$101.82	$199.68
Project Development (Note 7)	$50.40	$125.78	$239.60
Grid Integration (Note 8)	$3.98	$8.36	$15.94
EPC Markup (5%)	$15.28	$37.35	$72.79
EPC Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$320.96**	**$784.39**	**$1,528.57**
Land Acquisition	Leased	Leased	Leased
Owner's Project Development	PAC Provided	PAC Provided	PAC Provided
Owner's Project Management	PAC Provided	PAC Provided	PAC Provided
Owner's Legal Costs	PAC Provided	PAC Provided	PAC Provided
Owner's Costs, 2022 $MM	**$0.00**	**$0.00**	**$0.00**
Owner's Contingency (5%)	$16.0481	$39.2196	$76.4285
Builders Risk Insurance (0.48%)	$1.5406	$3.7651	$7.3371
Total Owners Costs With Contingency, 2022 $MM	**$17.589**	**$42.985**	**$83.766**
CAPEX, 2022 $MM	**$338.55**	**$827.38**	**$1,612.33**
Total Screening Level Project Costs, 2022 $/kWh	**$423.19**	**$413.69**	**$403.08**
CAPEX, 2022 $/kW	**$1,692.75**	**$1,654.75**	**$1,612.33**
Demolition Costs (end of life cycle) 2022$/kW (Note 9)	**$24**	**$24**	**$24**
O&M Cost, 2020 MM$/yr	**$8.46**	**$20.68**	**$40.31**
Fixed O&M (Note 10)	$8.46	$20.68	$40.31
Variable O&M	Included	Included	Included
Warranty	Included	Included	Included
O&M Cost, 2020 $/kWdc-yr	**$42.32**	**$41.37**	**$40.31**
Inflation Rate (%) (Note 11)	2.50%	2.50%	2.50%
Lifetime Cost (MM$)	**554.75**	**1335.75**	**2642.00**
Annual Lifetime Cost (MM$/year)	**27.74**	69.79	**132.10**

A - 8 Energy Storage: Flow

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE BESS GENERATION			
TECHNOLOGY		Flow Batteries	
BASE PLANT DESCRIPTION, MW	200	500	1000
Net Plant Output,kW	200,000	500,000	1,000,000
Capacity, hours	4	4	4
Design Life (Assuming 365 Cycles per Year)	25	25	25
Round Trip Efficiency (AC-AC)	70%	70%	70%
Estimated Annual Throughput (MWh) (80% Max Discharge)	49,840	124,600	249,200
kWh	800,000	2,000,000	4,000,000
ESTIMATED CAPITAL AND O&M COSTS (Note 7)			
Storage Block (Note 1)	$208.80	$484.96	$950.92
Storage BOS (Note 2)	$41.60	$99.84	$190.20
Power Equipment (Note 3)	$23.00	$54.92	$107.69
Controls & Communication (Note 4)	$0.30	$0.76	$1.50
System Integration (Note 5)	$38.40	$38.23	$187.44
Engineering, Procurement, & Construction (Note 6)	$43.20	$107.88	$215.68
Project Development (Note 7)	$54.40	$130.20	$248.00
Grid Integration (Note 8)	$4.00	$10.00	$20.00
EPC Markup (5%)	$20.69	$46.34	$96.07
EPC Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$434.39**	**$973.13**	**$2,017.50**
Land Acquisition	Leased	Leased	Leased
Owner's Project Development	PAC Provided	PAC Provided	PAC Provided
Owner's Project Management	PAC Provided	PAC Provided	PAC Provided
Owner's Legal Costs	PAC Provided	PAC Provided	PAC Provided
Owner's Costs, 2022 $MM	**$0.00**	**$0.00**	**$0.00**
Owner's Contingency (5%)	$21.7193	$48.6566	$100.8751
Builders Risk Insurance (0.48%)	$2.0850	$4.6710	$9.6840
Total Owners Costs With Contingency, 2022 $MM	**$23.804**	**$53.328**	**$110.559**
CAPEX, 2022 $MM	**$458.19**	**$1,026.46**	**$2,128.06**
Total Screening Level Project Costs, 2022 $/kWh	**$572.74**	**$513.23**	**$532.02**
CAPEX, 2022 $/kW	**$2,290.95**	**$2,052.92**	**$2,128.06**
Demolition Costs (end of life cycle) 2022$/kW (Note 9)	**$34**	**$33**	**$32**
O&M Cost, 2020 MM$/yr	**$12.88**	**$27.42**	**$54.99**
Fixed O&M (Note 10)	$11.45	$25.66	$53.20
Variable O&M	$0.03	$0.06	$0.13
Warranty	$1.40	$1.69	$1.66
O&M Cost, 2020 $/kWdc-yr	**$64.40**	**$54.83**	**$54.99**
Inflation Rate (%) (Note 11)	2.50%	2.50%	2.50%
Lifetime Cost (MM$)	**547.12**	**1186.79**	**2389.63**
Annual Lifetime Cost (MM$/year)	**21.88**	**47.47**	**95.59**

A - 9 Energy Storage: Gravity

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE BESS GENERATION			
TECHNOLOGY	**Gravity Batteries**		
BASE PLANT DESCRIPTION, MW	**200**	**500**	**1000**
Net Plant Output,kW	200,000	500,000	1,000,000
Capacity, hours	4	4	4
Design Life (Assuming 365 Cycles per Year)	50	50	50
Round Trip Efficiency (AC-AC)	83%	83%	83%
Estimated Annual Throughput (MWh) (80% Max Discharge)	59,096	147,740	295,480
kWh	800,000	2,000,000	4,000,000
ESTIMATED CAPITAL AND O&M COSTS (Note 7)			
Storage Block (Note 1)	$305.30	$680.98	$788.00
Storage BOS (Note 2)			
Power Equipment (Note 3)	$182.07	$455.18	$630.34
Controls & Communication (Note 4)	$0.00	$0.00	$0.00
System Integration (Note 5)	$0.00	$0.00	$0.00
Engineering, Procurement, & Construction (Note 6)			
Project Development (Note 7)	$97.47	$231.80	$288.00
Grid Integration (Note 8)			
EPC Markup (5%)	$29.24	$68.40	$85.32
EPC Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$614.09**	**$1,436.36**	**$1,791.66**
Land Acquisition	Leased	Leased	Leased
Owner's Project Development	PAC Provided	PAC Provided	PAC Provided
Owner's Project Management	PAC Provided	PAC Provided	PAC Provided
Owner's Legal Costs	PAC Provided	PAC Provided	PAC Provided
Owner's Costs, 2022 $MM	**$0.00**	**$0.00**	**$0.00**
Owner's Contingency (5%)	$30.7043	$71.8179	$89.5829
Builders Risk Insurance (0.48%)	$2.9476	$6.8945	$8.6000
Total Owners Costs With Contingency, 2022 $MM	**$33.652**	**$78.712**	**$98.183**
CAPEX, 2022 $MM	**$647.74**	**$1,515.07**	**$1,889.84**
Total Screening Level Project Costs, 2022 $/kWh	**$809.67**	**$757.54**	**$472.46**
CAPEX, 2022 $/kW	**$3,238.69**	**$3,030.14**	**$1,889.84**
Demolition Costs (end of life cycle) 2022$/kW (Note 9)	**$0.30**	**$0.24**	**$0.18**
O&M Cost, 2020 MM$/yr	**$16.19**	**$37.88**	**$47.25**
Fixed O&M (Note 10)	$16.19	$37.88	$47.25
Variable O&M	Included	Included	Included
Warranty	Included	Included	Included
O&M Cost, 2020 $/kWdc-yr	**$80.97**	**$75.75**	**$47.25**
Inflation Rate (%) (Note 11)	2.50%	2.50%	2.50%
Lifetime Cost (MM$)	**1092.27**	**2418.75**	**3281.92**
Annual Lifetime Cost (MM$/year)	**21.85**	**48.38**	**65.64**

A - 10 Energy Storage: Notes

Notes
Note 1. Storage Block includes the price for the most basic direct current (DC) storage element in an ESS (e.g., for lithium-ion, this price includes the battery module, rack, and battery management system, and is comparable to an electric vehicle (EV) pack price).
Note 2. Balance of System includes supporting cost components for the SB with container, cabling, switchgear, flow battery pumps, and heating, ventilation, and air conditioning (HVAC).
Note 3. Power Equipment includes bidirectional invertor, DC-DC converter, isolation protection, alternating current (AC) breakers, relays, communication interface, and software.
Note 4. Controls & Communication includes the energy management system for the entire ESS and is responsible for ESS operation. This may also include annual licensing costs for software. The cost is typically represented as a fixed cost scalable with respect to power and independent of duration.
Note 5. System Integration is the price charged by the system integrator to integrate subcomponents of a BESS into a single functional system. Tasks include procurement and shipment to the site of battery modules, racks with cables in place, containers, and power equipment. At the site, the modules and racks are containerized with HVAC and fire suppression installed and integrated with the power equipment to provide a turnkey system.
Note 6. EPC includes non-recurring engineering costs and construction equipment as well as shipping, siting and installation, and commissioning of the ESS. This cost is weighted based on E/P ratio.
Note 7. Project Development costs associated with permitting, power purchase agreements, interconnection agreements, site control, and financing.
Note 8. Grid Integration direct cost associated with connecting the ESS to the grid, including transformer cost, metering, and isolation breakers. For the last component, it could be a single disconnect breaker or a breaker bay for larger systems.
Note 9. Demo Costs include disconnection, disassembly/removal, site remediation, and recycle/disposal. Gravity Storage Demolition costs are for crane/building-based systems (i.e. Energy Vault).
Note 10. Fixed O&M prices for Lithium-Ion batteries includes estimated augmentation costs for the lifetime of the battery. Variable O&M is included in the fixed O&M for Li-Ion.
Note 11. Average inflation rates over the past decades have averaged 2.5% (US Federal Reserve)

A - 11 Solar + Energy Storage

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
SOLAR + ENERGY STORAGE GENERATION

PROJECT TYPE	SOLAR + ENERGY STORAGE				
PROJECT LOCATION	**Idaho Falls, ID**	**Lakeview, OR**	**Milford, UT**	**Rock Springs, WY**	**Yakima, WA**
BASE PLANT DESCRIPTION	**200 MW**	**200 MW**	**200 MW**	**200 MW**	**200 MW**
Nominal Output, MWac	200	200	200	200	200
Nominal Output, MWdc	260	260	260	260	260
Annualized Energy Production, MWh (Yr 1)	456,760	483,552	529,104	489,439	423,694
AC Capacity Factor at POI (%) (Note 1)	26.1%	27.6%	30.2%	27.9%	24.2%
Availability Factor, % (Note 2)	99%	99%	99%	99%	99%
Assumed Land Use, Acres (Note 2)	1600	1600	1600	1600	1600
PV Inverter Loading Ratio (DC/AC)	1.30	1.30	1.30	1.30	1.30
PV Degradation, %/yr (Note 2)	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2	2
ESTIMATED PERFORMANCE					
Base Load Performance @ (Annual Average)					
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000
ESTIMATED CAPITAL AND O&M COSTS					
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$140.8**	**$140.8**	**$140.8**	**$140.8**	**$140.8**
Modules	$66.8	$66.8	$66.8	$66.8	$66.8
Inverter	$8.0	$8.0	$8.0	$8.0	$8.0
Structural BOS	$20.0	$20.0	$20.0	$20.0	$20.0
Electrical BOS	$10.0	$10.0	$10.0	$10.0	$10.0
Installer OH (Labor Costs)	$20.0	$20.0	$20.0	$20.0	$20.0
EPC OH (Equipment and Material)	$10.0	$10.0	$10.0	$10.0	$10.0
EPC Markup	$6.0	$6.0	$6.0	$6.0	$6.0
Owner's Costs, 2022 MM$	**$24.0**	**$24.0**	**$24.0**	**$24.0**	**$24.0**
Engineering & Development OH	$4.0	$4.0	$4.0	$4.0	$4.0
Transmission Line	$2.0	$2.0	$2.0	$2.0	$2.0
PII (permitting fee, interconnection, commissioning)	$8.0	$8.0	$8.0	$8.0	$8.0
Land Acquisition (Note 3)	$0.0	$0.0	$0.0	$0.0	$0.0
Owner's Project Development	$10.0	$10.0	$10.0	$10.0	$10.0
Owner's Project Management	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Owner's Legal Costs	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Contingency and Insurance, 2022 MM$	**$5.5**	**$5.5**	**$5.5**	**$5.5**	**$5.5**
Owner's Contingency (3%) (Note 4)	$4.9	$4.9	$4.9	$4.9	$4.9
Builders Risk Insurance (.317%) (Note 4)	$0.5	$0.5	$0.5	$0.5	$0.5
Total Screening Level Project Costs, 2022 MM$	**$170.3**	**$170.3**	**$170.3**	**$170.3**	**$170.3**
State Taxes (Note 4)	**$8.4**	**$0.0**	**$9.5**	**$6.4**	**$12.3**
Balance of Plant Materials and Products	$7.25	$0.0	$8.27	$6.44	$10.57
Labor and Services	$1.20	$0.0	$1.2	0	$1.75
CAPEX, 2022 MM$	**$178.71**	**$170.27**	**$179.74**	**$176.71**	**$182.59**
Location Adjusted CAPEX 2022 MM$	**$175.14**	**$178.78**	**$174.35**	**$178.47**	**$188.07**
Total Screening Level Project Costs, 2022 $/kWdc	**$875.70**	**$893.90**	**$825.79**	**$859.85**	**$876.87**
Total Screening Level Project Costs, 2022 $/kWac	**$1,138.41**	**$1,162.07**	**$1,073.53**	**$1,117.80**	**$1,139.93**
Demolition Costs (end of life cycle) 2022 MM$ (Note 5)	**$5.88**	**$6.30**	**$5.82**	**$6.06**	**$6.18**
O&M Cost, 2020 MM$/yr (Note 6)	**$4.2**	**$4.2**	**$4.2**	**$4.2**	**$4.2**
Module cleaning	$0.433	$0.433	$0.433	$0.433	$0.433
Vegetation and/or Pest Management	$0.158	$0.158	$0.158	$0.158	$0.158
System inspection and monitoring	$0.449	$0.449	$0.449	$0.449	$0.449
Component parts replacement	$0.327	$0.327	$0.327	$0.327	$0.327
Module replacement	$0.075	$0.075	$0.075	$0.075	$0.075
Inverter replacement	$0.779	$0.779	$0.779	$0.779	$0.779
Land Lease	$0.547	$0.547	$0.547	$0.547	$0.547
Property tax	$0.433	$0.433	$0.433	$0.433	$0.433
Insurance	$0.507	$0.507	$0.507	$0.507	$0.507
Asset management and security (Note 6)	$0.410	$0.410	$0.410	$0.410	$0.410
Operations administration	$0.057	$0.057	$0.057	$0.057	$0.057
O&M Cost, 2020 $/kWac-yr	**$20.87**	**$20.87**	**$20.87**	**$20.87**	**$20.87**
Co-Located Energy Storage -200 MW x 4 hr Capacity					
Add-On Costs					
Capital Costs, 2022 $MM	$325.83	$307.5	$328.4	$323.6	$330.4
Incremental O&M Cost, 2022 $MM/Yr	$8.46	$8.5	$8.5	$8.5	$8.5

Notes
Note 1. Solar capacity factor supplied by PAC.
Note 2. Base plant descriptions provided by PAC.
Note 3. Land is assumed to be leased throughout the project lifetime and is thus included in yearly O&M values.
Note 4. State Tax rates provided by PAC.
Note 5. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.
Note 6. Third party long-term service agreement costs are included in the asset management and security line item.

A - 12 Wind + Energy Storage

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE WIND GENERATION					
PROJECT TYPE	Onshore Wind + BESS				
PROJECT LOCATION	Pocatello, ID	Arlington, OR	Monticello, UT	Medicine Bow, WY	Goldendale, WA
BASE PLANT DESCRIPTION	200 MW	200 MW	200 MW	200 MW	200 MW
ESTIMATED CAPITAL AND O&M COSTS					
BOP Project Capital Costs, 2022 $MM (w/o Owner's Costs)	**$263.1**	**$263.1**	**$263.1**	**$263.1**	**$263.1**
Wind Turbine Generators	$175.00	$175.00	$175.00	$175.00	$175.00
Met Mast	$1.05	$1.05	$1.05	$1.05	$1.05
Foundations	$14.19	$14.19	$14.19	$14.19	$14.19
Assembly & Installation	$8.57	$8.57	$8.57	$8.57	$8.57
Roads & Crane Pads	$9.49	$9.49	$9.49	$9.49	$9.49
O&M Building	$1.1	$1.1	$1.1	$1.1	$1.1
Collection System	$12.2	$12.2	$12.2	$12.2	$12.2
SCADA	$0.4	$0.4	$0.4	$0.4	$0.4
Switchgear/Substation (Note 2 & 3)	$15.9	$15.9	$15.9	$15.9	$15.9
Step-Up Transformer & Interconnection (Note 4)	$4.92	$4.92	$4.92	$4.92	$4.92
Aircraft Detection Lighting System	$0.90	$0.90	$0.90	$0.90	$0.90
EPC Fee (8%)	$19.49	$19.49	$19.49	$19.49	$19.49
Owner's Costs Without Contingency, 2022 $MM	**$5.5**	**$6.2**	**$5.5**	**$5.9**	**$6.4**
Project Design	$2.0	$2.0	$2.0	$2.0	$2.0
Owner's Engineer	$0.17	$0.17	$0.17	$0.17	$0.17
Land Lease & Development	$2.4	$2.4	$2.4	$2.4	$2.4
Permitting (Note 5)	$0.6	$1.4	$0.6	$1.1	$1.6
Wildlife Studies	$0.2	$0.2	$0.2	$0.2	$0.2
Eagle Take Permits	$0.09	$0.09	$0.09	$0.09	$0.09
Capital Spares	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M
Subtotal - Capital Costs, 2022 $MM	**$268.6**	**$269.3**	**$268.6**	**$269.0**	**$269.5**
Owner's Contingency (5% of Capital Cost)	$13.4	$13.5	$13.4	$13.5	$13.5
Total - Costs With Contingency, 2022 $MM	**$282.0**	**$282.8**	**$282.0**	**$282.5**	**$283.0**
State Taxes, $MM (Note 6)	**$14.7**	**$0.0**	**$14.3**	**$14.7**	**$21.5**
Balance of Plant Materials and Products	$12.5	NA	$14.3	$12.5	$18.3
Labor and Services	$2.2	NA	NA	$2.2	$3.2
CAPEX, 2022 $MM	**$296.73**	**$282.79**	**$296.32**	**$297.19**	**$304.46**
Location Adjusted CAPEX 2022 $MM	**$299.70**	**$294.10**	**$305.21**	**$294.21**	**$310.55**
Total Screening Level Project Costs, 2022 $/kW	**$1,498.51**	**$1,470.50**	**$1,526.07**	**$1,471.07**	**$1,552.76**
Demolition Costs (end of life cycle) 2022 $MM (Note 6)	**$11.89**	**$11.89**	**$11.89**	**$11.89**	**$11.89**
O&M Cost, 2022 $MM/yr	**$8.6**	**$8.6**	**$8.6**	**$8.6**	**$8.6**
O&M Cost, 2022 $/kW-yr	$43.0	$43.0	$43.0	$43.0	$43.0
Co-Located Energy Storage - 4 hr Capacity					
Add-On Costs					
Capital Costs, 2022 $MM	$318	$301	$321	$317	$326
Incremental O&M Cost, 2022 $MM/Yr	$8.46	$8.46	$8.46	$8.46	$8.46

Notes

Note 1. 20 MW Substation assumes: Tie in 230kV line through three disconnects, a single 230kV breaker connection, & a 1200A, 34.5kV GIS switchgear housed in a building.
Note 2. 200 MW Substation assumes: Three breaker ring 230kV AIS switchgear & (2) 2500A, 34.5kV GIS switchgear housed in a building.
Note 3. 20 MW Plant assumes (1) 30 MVA (230 kV/34.5 kV) transformer & 200 MW Plant assumes (2) 125 MVA (230 kV/34.5 kV) transformer. I one mile interconnection tie line is assumed for both
Note 4. Permitting cost assumes the permitting matrix from the 2022 PacifiCorp All-Source RFP is utilized.
Note 5. State Tax information provided by PacifiCorp.
Note 6. Reclamation costs included in Demolition costs. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.

Appendix A

A - 13 Wind + Solar + Energy Storage

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE WIND + SOLAR + ENERGY STORAGE GENERATION					
PROJECT TYPE	WIND + SOLAR + ENERGY STORAGE				
PROJECT LOCATION	Idaho Falls, ID	Lakeview, OR	Milford, UT	Rock Springs, WY	Yakima, WA
BASE PLANT DESCRIPTION	**200 MW**	**200 MW**	**200 MW**	**200 MW**	**200 MW**
Nominal Output, MWac	200	200	200	200	200
Nominal Output, MWdc	260	260	260	260	260
Annualized Energy Production, MWh (Yr 1)	466,760	483,552	529,104	489,439	423,894
AC Capacity Factor at POI (%) (Note 1)	26.1%	27.6%	30.2%	27.9%	24.2%
Availability Factor, % (Note 2)	99%	99%	99%	99%	99%
Assumed Land Use, Acres (Note 2)	1600	1600	1600	1600	1600
PV Inverter Loading Ratio (DC/AC)	1.30	1.30	1.30	1.30	1.30
PV Degradation, %/yr (Note 2)	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2	2
ESTIMATED PERFORMANCE					
Base Load Performance @ (Annual Average)					
Net Plant Output, kW	200,000	200,000	200,000	200,000	200,000
ESTIMATED CAPITAL AND O&M COSTS					
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$140.8**	**$140.8**	**$140.8**	**$140.8**	**$140.8**
Modules	$66.8	$66.8	$66.8	$66.8	$66.8
Inverter	$8.0	$8.0	$8.0	$8.0	$8.0
Structural BOS	$20.0	$20.0	$20.0	$20.0	$20.0
Electrical BOS	$10.0	$10.0	$10.0	$10.0	$10.0
Installer OH (Labor Costs)	$20.0	$20.0	$20.0	$20.0	$20.0
EPC OH (Equipment and Material)	$10.0	$10.0	$10.0	$10.0	$10.0
EPC Markup	$6.0	$6.0	$6.0	$6.0	$6.0
Owner's Costs, 2022 MM$	**$24.0**	**$24.0**	**$24.0**	**$24.0**	**$24.0**
Engineering & Development OH	$4.0	$4.0	$4.0	$4.0	$4.0
Transmission Line	$2.0	$2.0	$2.0	$2.0	$2.0
PII (permitting fee, interconnection, commissioning)	$8.0	$8.0	$8.0	$8.0	$8.0
Land Acquisition (Note 3)	$0.0	$0.0	$0.0	$0.0	$0.0
Owner's Project Development	$10.0	$10.0	$10.0	$10.0	$10.0
Owner's Project Management	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Owner's Legal Costs	PAC to input values	PAC to input values	PAC to input values	PAC to input values	PAC to input values
Contingency and Insurance, 2022 MM$	**$5.5**	**$5.5**	**$5.5**	**$5.5**	**$5.5**
Owner's Contingency (3%) (Note 4)	$4.9	$4.9	$4.9	$4.9	$4.9
Builders Risk Insurance (.317%) (Note 4)	$0.5	$0.5	$0.5	$0.5	$0.5
Total Screening Level Project Costs, 2022 MM$	**$170.3**	**$170.3**	**$170.3**	**$170.3**	**$170.3**
State Taxes (Note 4)	**$8.4**	**$0.0**	**$9.5**	**$6.4**	**$12.3**
Balance of Plant Materials and Products	$7.25	$0.0	$8.27	$6.44	$10.57
Labor and Services	$1.20	$0.0	$1.2	0	$1.75
CAPEX, 2022 MM$	**$178.71**	**$170.27**	**$179.74**	**$176.71**	**$182.59**
Location Adjusted CAPEX 2022 MM$	**$175.14**	**$178.78**	**$174.35**	**$178.47**	**$188.07**
Total Screening Level Project Costs, 2022 $/kWdc	**$875.70**	**$893.90**	**$825.79**	**$859.85**	**$876.87**
Total Screening Level Project Costs, 2022 $/kWac	**$1,138.41**	**$1,162.07**	**$1,073.53**	**$1,117.80**	**$1,139.93**
Demolition Costs (end of life cycle) 2022 MM$ (Note 5)	**$5.88**	**$6.30**	**$5.82**	**$6.06**	**$6.18**
O&M Cost, 2020 MM$/yr (Note 6)	**$4.2**	**$4.2**	**$4.2**	**$4.2**	**$4.2**
Module cleaning	$0.433	$0.433	$0.433	$0.433	$0.433
Vegetation and/or Pest Management	$0.158	$0.158	$0.158	$0.158	$0.158
System inspection and monitoring	$0.449	$0.449	$0.449	$0.449	$0.449
Component parts replacement	$0.327	$0.327	$0.327	$0.327	$0.327
Module replacement	$0.075	$0.075	$0.075	$0.075	$0.075
Inverter replacement	$0.779	$0.779	$0.779	$0.779	$0.779
Land Lease	$0.547	$0.547	$0.547	$0.547	$0.547
Property tax	$0.433	$0.433	$0.433	$0.433	$0.433
Insurance	$0.507	$0.507	$0.507	$0.507	$0.507
Asset management and security (Note 6)	$0.410	$0.410	$0.410	$0.410	$0.410
Operations administration	$0.057	$0.057	$0.057	$0.057	$0.057
O&M Cost, 2020 $/kWac-yr	**$20.87**	**$20.87**	**$20.87**	**$20.87**	**$20.87**
Co-Located Energy Storage -200 MW x 4 hr Capacity					
Add-On Costs					
Capital Costs, 2022 $MM	$325.83	$307.5	$326.4	$323.6	$333.4
Incremental O&M Cost, 2022 $MM/Yr	$8.46	$8.5	$8.5	$8.5	$8.5
Co-Located Energy Storage - 200 MW x 4 hr Capacity+200 MW Wind					
Add-On Costs					
Capital Costs, 2022 $MM	$599.22	$575.8	$606.5	$591.8	$616.6
Incremental O&M Cost, 2022 $MM/Yr	$17.08	$17.06	$17.06	$17.06	$17.06

Notes

Note 1. Solar capacity factor supplied by PAC.
Note 2. Base plant descriptions provided by PAC.
Note 3. Land is assumed to be leased throughout the project lifetime and is thus included in yearly O&M values.
Note 4. State Tax rates provided by PAC.
Note 5. Demolition costs are seen as an optional end-of-life cost, as other options like repowering the plant are available.
Note 6. Third party long term service agreement costs are included in the asset management and security line item.

APPENDIX

B – TECHNICAL PARAMETERS

Appendix B

B - 1 Energy Storage Technical Parameters

ENERGY STORAGE - KEY TECHNICAL PARAMETERS BY TECHNOLOGY

	Parameter	Li-Ion	Flow	Iron-Air (single vendor - Form Energy)	Gravity	CAES
1	Power capacity: minimum maximum (peak), spinning reserve	Typical grid-scale system has a min power capacity of 1MW+ per power conversion unit. There is no technical limit to the number of power conversion units connected in parallel within the system. As with any inverter-based system, a "virtual spinning reserve" function is inherent, supported by fast response to the max power output capacity and overload capability if the DC system is designed to support it (typically up to 120% of rated current at 10 sec duration, higher for millisecond-level durations). It should be noted that inverter-based systems can provide spinning reserve capability without the efficiency loss and the cost of using extra fuel	Typical system has a min power capacity of 78KW to 3 MW per power conversion unit. There is no technical limit to the number of power conversion units connected in parallel within the system. As with any inverter-based system, a "virtual spinning reserve" function is inherent, supported by fast response to the max power output capacity and overload capability if the DC system is designed to support it (typically up to 120% of rated current at 10 sec duration, higher for millisecond-level durations). Note that the response time of flow battery systems through the entire power output range can be slower as compared to Li-ion BESS due to the need of change electrolyte flow rates. Still, it's within the range of conventional spinning reserve (rotating generators)	The basic Power Block has a capacity of 3.5 MW, 350MWh: spinning reserve capability is not known but as an inverter-based system it's expected to be available. The system is targeting very long duration (up to 100 hrs.).	Gravity storage is an emerging technology with no large-scale commercial facilities currently operating and no detailed technical information available publicly. A practical power output range has not yet been established. Energy Vault offers a modular system with 4MW/8-16hr minimum capacity, and also claims to have agreement for development of several Gigawatt-hour scale facilities in the US. Gravitricity offers systems in 1-20MW 25-8hr range. There are two different prime movers used in gravity energy storage systems - direct mechanical drive actuated by a falling weight, and a water or air turbine activated by process fluid (water or air) moving under influence of a solid weight (piston). Both have good spinning reserve capabilities due to inherently high ramp rates and relatively linear power delivery	Compressed Air Energy Storage is an emerging technology with several operating commercial pilots and several large-scale commercial projects under development. Detailed technical information is not publicly available. The power output range and its increments are controlled by the available turbomachinery (compressors and expanders). Standard turboexpanders are normally limited to 15 MW shaft power, however larger turbo-generators are likely to be developed in the future as the CAES technology matures. The spinning reserve capability of such plants will be similar to that of the simple cycle GT power plant. However, in Adiabatic CAES (A-CAES) systems that have the highest round trip efficiency, the response time and ramp rate may be affected by the responsiveness of the reheating cycle. This is expected to make the overall system response time closer to that of a CCGT power plant
2	Max system power capacity (if applicable, e.g., if there is a limit to the number of paralleled PCS units)	There is no technical limit to the number of PCS units that can be paralleled, within the range of existing power plant output capacities	There is no technical limit to the number of PCS units that can be paralleled, within the range of existing power plant output capacities	There is no technical limit to the number of Power Block units that can be paralleled, within the range of existing power plant output capacities	There is no technical limit to the number of mechanically or hydraulically-driven generator units that can be paralleled, within the range of existing power plant output capacities	There is no technical limit to the number of turbogenerator units that can be paralleled, within the range of existing power plant output capacities
3	Voltage/phase	The majority of Power Conversion Systems (bi-directional inverters) have their output at 480VAC or 600VAC, 3-phase. Many PCS systems also have built-in transformer allowing interconnection at medium voltage (e.g. 13.8kV)	The majority of Power Conversion Systems (bi-directional inverters) have their output at 480VAC or 600VAC, 3-phase. Many PCS systems also have built-in transformer allowing interconnection at medium voltage (e.g. 13.8kV)	No information available, expected to be similar to other inverter-based ESS systems	Gravity systems use standard industrial/power plant generators that typically have medium-voltage terminal output (6-15kV), 3-phase	CAES systems use standard industrial/power plant generators designed for turbine applications, which typically have medium-voltage terminal output (6-15kV), 3-phase
4	Energy storage capacity for a base unit/minimal functional system size (scalable by using multiple units)	Typically ranges from 250kWh to 4 MWh	Typically ranges from 22kWh to 1 MWh	350MWh	25 -20MWh	Pilot CAES plants have been operating at low capacities but a commercially feasible CAES facilities currently under development are in the 100MW+, long-duration category (such as PG&E San Joaquin CAES, at 300MW/10hr). The existing CAES systems use a scalable, but not modular technology with regards to their energy storage component
5	Max system energy storage capacity (e.g., if there is a limit to the number of paralleled ES units)	There is no technical limit to the number of energy storage units that can be paralleled	There is no technical limit to the number of energy storage units that can be paralleled	There is no technical limit to the number of energy storage units that can be paralleled	There is no technical limit to the number of energy storage units that can be paralleled	There is no technical limit to the capacity of compressed air energy storage, within the existing range of power plant capacities
6	Response time: from standby (cold stby, if applicable to specific technology) to 100% power output	~1 sec (conservative)	~1-2 sec	No information available; expected to be similar to other inverter-based ESS systems; however the ramp rate is unknown	Not available, technically possible to match battery-based technology performance	60400 sec depending on the compressor and expander utilized
7	Response time: from 100% charging input to 100% output	~2 sec (200 ms in frequency response applications)	~2 sec	No information available; expected to be similar to other inverter-based ESS systems; however the ramp rate is unknown	Not available, technically possible to match battery-based technology performance	60400 sec depending on the compressor and expander utilized
8	C-rate range	1 - 16	<.25	No information available	Data not available. Typically designed for long duration applications (4-8++ hrs. or .25C - .125C)	Data not available. Depends on the ratio of storage vs compressor/expander capacity. Typically designed for long duration applications (5-10++ hrs., or .2C - .1C)
9	C-curve for charging and discharging	Charging capacity is linear 10% true SOC and 75-90% (depending on cell chemistry) true SOC, asymptotically slowing above that range, leading to the practical SOC range not using the full physical SOC range	<.25 Linear for charging and discharging within full SOC range.	No information available	Data not available. Charging and discharging capacity is expected to be linear within the full SOC range.	Data not available. Charging capacity is expected to be an S-curve, with significant deviations from linear at the extreme true SOC values. Likely mitigated by setting practical SOC range narrower than the true SOC range, similar to Li-ion battery based energy storage
10	Round trip efficiency (AC in to AC out), excluding auxiliary loads	PNNL (historical) - 83%, vendor supplied data 91-94% (year 0, including thermal management loads); Inverter-only: 98.3% at full load	65% (Vn-RedOx, PNNL); vendor supplied data >72%	38% (at full power, including auxiliary loads and PCS losses)	83% (PNNL), vendor supplied data - 88-92%	70% (eesi.org, for A-CAES), 52% (PNNL, historical)
11	Auxiliary power consumption for a minimally sized system block (scalable by paralleling many blocks)	1-10% of nameplate power depending on ambient conditions, load and coiling system efficiency	5-10% of nameplate power, depending on load	No information available	Data not available, expected to be significantly lower than Li or Flow BESS systems as no cooling or circulation pumps required	Data not available, expected to be lower than Li or Flow BESS systems etc. as no cooling or circulation pumps required. However, heat recovery for A-CAES system may introduce such loads
12	Guaranteed system availability	Varies by vendor, ~97% is typical	Data not available	No information available	Data not available	Data not available
13	Capacity degradation rate (calendar)	1%/year	<1%/year	No information available	No vendor data available, anticipated to be 0%/year	No vendor data available, anticipated to be 0%/year
14	Cycling capacity degradation (assuming full charge-discharge cycle)	vendor data used in performance guarantees - on an average 2.2%/year (including calendar degradation and cycling degradation at 1 cycle per day)	No vendor data available, anticipated to have low or no cycling degradation (provided timely electrolyte exchange)	No information available; indirectly - warranty covers 10 years at 13 full cycles per year	No vendor data available, anticipated to be 0%/year	No vendor data available, anticipated to be 0%/year provided proper turbomachinery O&M
15	Design lifespan of the system assuming 365 cycles per yr.	16 yrs. (PNNL data); vendor data: 15-20 yrs.	12 yrs. (Vn-RedOX, PNNL); vendor data - 50+ yrs.	No information available; indirectly - warranty covers 10 years	Vendor data - 49+ yrs.	60 yrs. (PNNL)
16	Max number of lifetime system charge/discharge cycles	LFP: min 3,000-4,000 Equivalent Full Cycles (without losing more than 20% of initial capacity)	Unlimited (with electrolyte and electrode replacement)	130	Unlimited (with proper mechanical machinery O&M)	Unlimited (with proper turbomachinery O&M)
17	Major required service and maintenance required during the design lifespan of the system	Capacity maintenance (adding battery modules to compensate for capacity degradation); coolant replacement (for liquid-cooled systems)	Electrolyte replacement, scheduled replacement of electrolyte pump and valve components	No information available	Mechanical maintenance (lubrication, bearing and linkage service etc.), pump and turbine component replacement (for systems using a working fluid)	Compressor and turboexpander maintenance (lubricant change, bearing service); circulation pumps and valves service (for A-CAES)

APPENDIX O – WASHINGTON 2021 IRP TWO-YEAR PROGRESS REPORT ADDITIONAL ELEMENTS

Introduction

Washington passed the Clean Energy Transformation Act (CETA) in 2019, which combines directives for utilities to pursue a clean energy future with assurances that benefits from a transformation to clean power are equitably distributed among all Washingtonians.[1]

The Washington Utilities and Transportation Commission began rulemakings to implement CETA in June 2019, and the first phase concluded in December 2020. As directed by the legislation and the new CETA rules, beginning January 1, 2023, the Company must file a two-year progress report at least every two years after PacifiCorp has filed its IRP.[2] This two-year progress report must include the following:

- Updated load forecast, demand-side resource assessment, including a new conservation potential assessment; resource costs; and portfolio analyses and preferred portfolios;
- Other updates necessary due to changing state or federal requirements, or significant changes to economic or market forces; and
- Update any elements found in the utility's current clean energy implementation plan (CEIP).[3]

The Company's updated load forecast can be found in Volume 1, Appendix A; demand-side resource assessment and new conservation potential assessment can be found in Chapter 6 and the ***Specific Actions*** section below; resource costs can be found in Volume I, Chapter 7; and relevant portfolio analyses can be found in Volume I, Chapters 8 and 9, and the ***Interim and Specific Targets*** section below.[4] Relevant state and federal policy updates, as well as changes to economic or market forces, can be found in Volume I, Chapter 3.[5]

Aligned with the refiled CEIP,[6] this 2021 IRP Two-Year Progress Report includes updates on the following CEIP elements: Interim and Specific Targets; Updated Inputs, including portfolio

[1] 2019 WA Laws Ch. 288.
[2] WAC 480-100-625.
[3] *Id.* -625(4).
[4] *Id.* -625(4)(a).
[5] *Id.* -625(4)(b).
[6] PacifiCorp filed its first Clean Energy Implementation Plan (CEIP) on December 29, 2021, with the Washington Utilities and Transportation Commission (WUTC) in docket UE-210289. The Company filed a Revised Errata to the CEIP to make a small correction to a workpaper that resulted in a change in the calculated incremental cost. Consistent with UE-220376, Order 06, the Company refiled its 2021 CEIP on March 13, 2023, and relevant CEIP elements are included in this 2021 IRP Two-Year Progress Report.

analysis and preferred portfolios; Customer Benefit Indicators; Specific Actions, including both supply and demand-side actions; Incremental Costs; Public Participation; and Annual Reporting.

Each of these updated CEIP elements are discussed below. Additionally, consistent with WAC 480-100-650, more detailed and specific reporting on CEIP targets, actions, and CBIs will be included in the Company's annual clean energy progress report due this summer, and CEIP biennial update due later this fall.

Interim and Specific Targets

CETA's clean energy transformation requires Washington utilities to eliminate coal-fired resources from its allocation of electricity to Washington retail electric customers by 2026; ensure all retail sales of electricity to Washington electric customers are greenhouse gas neutral by 2030; and ensure that non-emitting electric generation and electricity from renewable resources supply one hundred percent of all retail sales of electricity to Washington electric customers by 2045.[7]

Prior to 2045, CETA allows for up to 20 percent of the greenhouse gas neutral standard to be met with alternative compliance in the form of alternative compliance payments, unbundled RECs, energy transformation projects, or energy recovery from a municipal solid waste facility.[8] To achieve the 2045 target, the clean energy standard must be met with 100 percent non-emitting generation or electricity from renewable energy resources. Furthermore, PacifiCorp must demonstrate that it "has made progress toward and has met the standards in this section at the lowest reasonable cost."[9]

Consistent with these requirements and WAC 480-100-640, the Company proposes interim targets to demonstrate its trajectory toward meeting CETA's decarbonization targets. Updated interim targets are based on data and methodologies consistent with portfolio development and modeling in Volume 1, Chapters 8 and 9, and with CEIP requirements. Specifically, CEIP targets are demonstrated for a least-cost, least-risk portfolio optimized under the price policy assumption that includes societal cost of greenhouse gas emissions (SCGHG).[10]

As shown in Volume I, Chapter 8 (Modeling and Portfolio Evaluation), Figure 8.4 – the SCGHG starts at just over $80/ton in 2023 and reaches about $170/ton in 2042. In addition to the assumed carbon dioxide price, there is an additional forecasted cost of allowances under the cap-and-invest program established in the Climate Commitment Act passed by Washington Legislature in 2021. This forecasted allowance cost is applied to all emissions from the Chehalis natural gas plant located in Washington. The modeled allowance cost reflects analysis conducted by Vivid

[7] WAC 480-100-610(1-3).
[8] RCW 19.405.040(1)(b).
[9] WAC 480-100-610(5).
[10] The SCGHG dispatch adder is modeled in both the resource acquisition decision (capacity expansion in the LT model), and in operations (dispatch in the MT and ST models) as described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Economics for the Washington Department of Ecology and starts at $58/ton in 2023.[11] For more discussion of the system-wide portfolio impacts of the SC price-policy assumptions and CETA-related portfolio impacts, see results in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).

Based on these updated portfolio inputs, the Company anticipates supplying 26 percent renewable and non-emitting energy to serve Washington retail sales in 2023, increasing to 33 percent in 2025, to 82 percent in 2030, and finally over 100 percent beginning in 2032 and maintaining this percentage for the remainder of the Company's planning period.

Interim Targets

This section includes PacifiCorp's interim compliance targets for the first CETA action period (2022-2025), and to achieve CETA's 2030 and 2045 targets.

Figure O.1 reports PacifiCorp's updated interim targets that are derived from the portfolio denoted W-10 CETA.[12] This portfolio was developed to meet CETA's 2030 and 2045 decarbonization targets under the SCGHG price policy assumption. In the figure interim targets are divided into two forecast ranges: the first focuses on meeting CETA's 100 percent GHG neutrality standard by 2030, and the second focuses on meeting the 100 percent non-emitting and renewable energy target by 2045. As shown in the figure, the Company expects to have achieved CETA's ambitious decarbonization targets well over a decade in advance of the 2045 deadline.

Post-2030, the last three years to reach the 2045 objective are beyond the Company's current 20-year study period. Rather than creating extrapolated and imprecise forecasts for every data point underlying the analysis to extend into 2045, the company has extrapolated the last three years of data based on the already optimized and established trajectory. However, this exercise was unnecessary given that the portfolio shows 100 percent clean energy as a percentage of Washington retail sales by 2032.

[11] Washington DOE Summary of market modeling and analysis of the proposed Cap and Invest Program, at 4 (Jun. 2022) (available here: https://ecology.wa.gov/DOE/files/4a/4ab74e30-d365-40f5-9e8f-528caa8610dc.pdf; accessed Mar. 31, 2023).
[12] Several portfolios were developed to analyze the impacts of CETA in various planning scenarios, and are defined in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Figure O.1 - Interim Targets

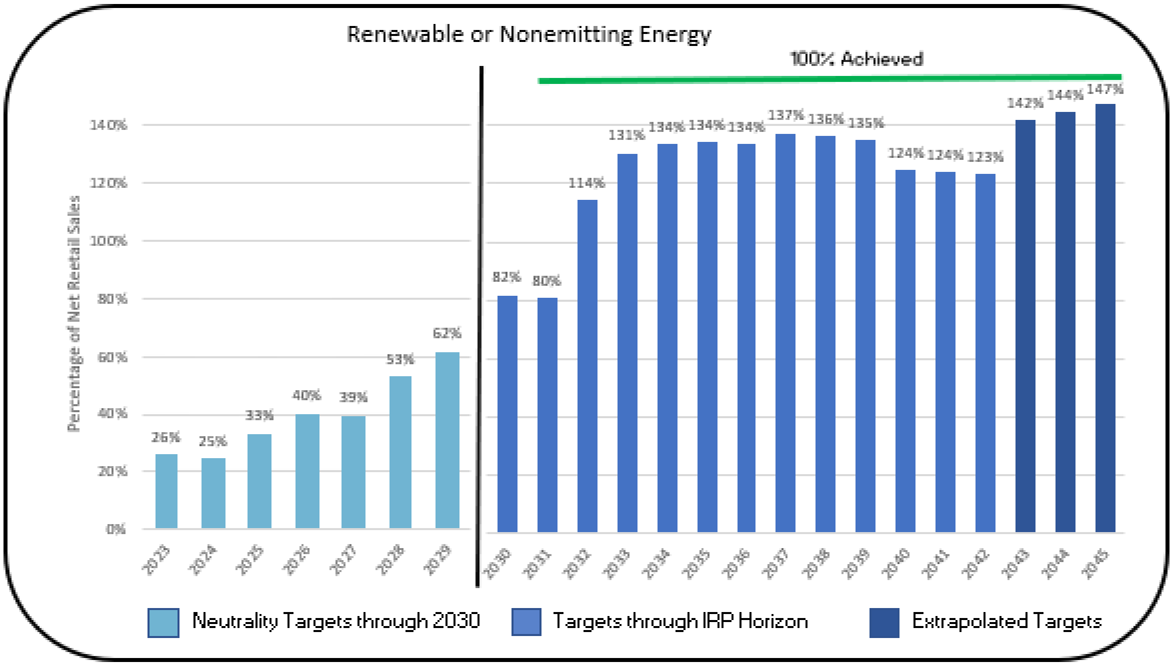


Table O.1 below reports updated interim targets for the Company's first CEIP action period for years 2022 through 2024, reported as annual megawatt hours of energy rather than as percentages. Since this two-year IRP progress report is forward-looking, portfolio inputs, outputs, and interim targets begin from year 2023. However given the Company's current CEIP focuses on the CEIP compliance period from 2022 to 2025, this same compliance period is reflected below. The values for 2022 are from the Company's March 13, 2023 Refiled CEIP and have not been updated, and are informed by the company's historical performance under median water conditions, a factor in developing expected resource behaviors and Washington retail sales.

Table O.1 - Interim Compliance Targets (MWh)

	2022[1]	2023	2024	2025	Total
Retail Electric Sales	4,051,128	4,128,751	4,141,107	4,106,386	16,427,372
Projected Renewable and Non-emitting Energy	1,262,111	1,081,277	1,028,236	1,367,667	4,739,291
Net Retail Sales	2,789,017	3,047,474	3,112,871	2,738,719	11,688,081
Target Percentage	31%	26%	25%	33%	
Interim Compliance Target	1,262,111	1,081,277	1,028,236	1,367,667	4,739,291

[1] Originally estimated target for 2022 based on Refiled 2021 CEIP, March 13, 2023

These updated interim targets reflect both updates from the Company's portfolio results, as well as updated resource allocation assumptions. Importantly, increases in system load, changes in price curves and fuel inputs, and development in federal regulation like the Ozone Transport

Rule, have driven significant growth in system renewable resources across the planning horizon. However, ongoing wholesale energy market volatility has forced the Company to consider options to mitigate increasing net power costs that adversely affect PacifiCorp's near-term CETA targets. Compliance with CETA continues to be supported by the IRP with the addition of non-emitting system resources. Ongoing negotiations in MSP, updated REC assumptions, and a realignment of assumptions about uncertain future Washington resource allocations have all led to a lower percentage of system renewable energy for Washington customers in the near-term as compared to the Company's current CEIP.

Given these updates, the Company estimates by 2025 that 33 percent of Washington retail sales will be served by renewable and non-emitting energy, and as discussed above, the Company will substantially decarbonize its system and achieve CETA's 2045 requirements almost a decade early.

Target Development

Updated interim target development is consistent with PacifiCorp's Refiled 2021 CEIP, Chapter 1, where the Company's Washington allocation of the updated CEIP-compliant portfolio of resources was analyzed based on an updated forecast of retail electric sales to Washington.[13] This section discusses the assumptions that informed these updated interim targets.

To estimate the amount and mix of energy forecasted to serve Washington customers for the 2023-2045 period, PacifiCorp summed annual generation from its qualifying resources allocated to Washington customers under the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) for existing resources and generally assumed that these assumptions hold into the future, in the absence of an agreed upon future allocation methodology.[14] The allocations assumed for Washington in this update are the Company's best estimate of future allocations at this time, and are best aligned with other ongoing filings in Washington.

To calculate the energy and the total amount of renewable and carbon non-emitting energy allocated to Washington customers, the company made the assumptions set forth below. Generally, where a resource is assumed to generate RECs, where one REC is generated for one megawatt-hour of renewable energy, the resource was assumed to generate CETA-compliant energy. In addition to REC-generating resources, it was assumed that all Washington-allocated energy from

[13] PacifiCorp's Revised 2021 CEIP can be found at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=277&year=2021&docketNumber=210829.

[14] The WIJAM and the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol) define how resources and costs are allocated to Washington customers through December 21, 2023. The Washington Utilities and Transportation Commission approved the WIJAM and 2020 Protocol in its Final Order 09/07/12 in docket UE-191024 et. al., effective January 1, 2021. The company is in the process of negotiating its Multi-State Process (MSP) cost allocation methodology with the commissions and stakeholders in the six states it serves. More information can be found in Volume I, Chapter 3.

non-emitting resources was also CETA compliant, namely hydroelectric, nuclear and hydrogen non-emitting peaking plants.[15] In summary, the resource allocation assumptions are:

1. Allocation of energy for all system renewable resources, existing and proxy, are allocated according to system-generation (SG) factors, consistent with the WIJAM.
2. Allocation of energy for new non-emitting proxy resources are allocated on SG factors, consistent with the WIJAM.
3. Allocation of energy for all Washington qualifying-facilities (QFs) are assumed to be situs to Washington. No energy is allocated from QFs not originating in Washington, consistent with Washington Utilities and Transportation Commission policy.
4. Washington customers are assumed to participate in a limited set of emitting resources as defined under the West Control Area Inter-Jurisdictional Allocation Methodology (WCA):
    a. Washington customers receive costs and benefits from PacifiCorp's interest in the Colstrip Unit 4 and Jim Bridger Unites 1-4 thermal resources, subject to elimination of all costs and benefits from coal-fueled Colstrip 4 and Jim Bridger Units 3 and 4 until by the end of 2025. It is assumed that in the event a coal-fueled resource converts to gas before 2026, that Washington customers can participate until the end 2029.
    b. Washington customers participate in two gas-fired units, Chehalis and Hermiston, through the end-of-life.

Given the assumed allocations of resource energy and costs to Washington, CETA-compliant energy is determined given the following:

1. For REC-generating resources, generation of CETA-compliant energy is consistent with the company's REC entitlement start and end date.
2. Customer preference and voluntary renewable resources were not assumed to generate RECs for the system or the state of Washington and thus are not included in the allocation of renewable energy.
3. All renewable and non-emitting resources were assumed to be CETA compliant, including wind, solar, geothermal, hydro, nuclear and hydrogen non-emitting peaking plants. For renewable resources co-located with battery storage, RECs were assumed to be generated pre-storage; no RECs are generated at battery discharge.
4. Emitting generation (coal or gas-fueled resources) are not CETA compliant.

Washington retail electric sales were defined as total energy served to customers annually, net of distributed generation, existing and optimized energy efficiency and demand-side management (DSM) resources. Retail electric load does not include MWh delivered from Washington qualifying facilities under the federal Public Utilities Regulatory Policies Act of 1978 (PURPA).[16] CETA compliance targets were calculated annually as a percentage of Washington retail electric

[15] WAC 480-100-610(3) states that by January 1, 2045, each utility must ensure that "non-emitting electric generation and electricity from renewable resources supply one hundred percent of all retail sales of electricity to Washington electric customers".
[16] RCW 19.405.020(36)(a)

sales. Annual targets for CETA's 2030 and 2045 requirements were calculated as a percentage of Washington retail electric sales to be the total renewable and carbon non-emitting energy the Company estimates will be provided to Washington customers.

For purposes of this CEIP, PacifiCorp relies on the use of unbundled RECs to satisfy the alternative compliance component of the 2030 and 2031 greenhouse gas neutral standard. PacifiCorp may meet up to 20 percent of its aggregate retail electric sales over the four-year compliance period with alternative compliance from January 1, 2030, through December 31, 2044.

For further discussion specific to development of the CETA-compliant portfolio and interim targets, please see subsection Interim Target Shortfall Resolution.

Specific Targets

Renewable energy targets, energy efficiency and demand response targets will evolve from the ongoing CEIP, based on updated outputs and analysis from this IRP Progress Report. The Company's November 1, 2023 Biennial CEIP Update will provide updates to all general CEIP requirements, including specific targets.

Customer Benefit Indicators

As part of its CEIP compliance report to be filed July 1, 2023, PacifiCorp will report and track customer benefit indicators (CBIs) that are identified in Chapter 2 of the Company's CEIP. These metrics will report on the progress made in each CBI as PacifiCorp moves through the four-year CEIP cycle. Furthermore, PacifiCorp is considering additional input on the Company's CBIs in response to public comment and stakeholder feedback received in Docket UE-210829. Of note, the Washington Department of Health (DOH) recently updated the agency's highly-impacted communities (HIC) analysis in January 2022.[17] Based on this DOH update, the Company concluded there is one additional HIC located within PacifiCorp's Washington service territory compared to what was considered in the Company's 2021 CEIP. The Company is in the process of including this additional HIC within the baseline and will account for it when developing metrics for the July 1, 2023, compliance report.

The process of updating the metrics for the July 1, 2023, filing will be based largely on survey results. As was the case with the Company's December 30, 2021, filing, the CBI metrics will require PacifiCorp to use survey responses to identify energy burden for vulnerable populations in the Washington service area. This survey is expected to launch in April 2023 and will include both an email and telephone effort to accumulate necessary data.

[17] *See generally,* Washington Department of Health, Information by Location (IBL) (available here: https://doh.wa.gov/data-and-statistical-reports/washington-tracking-network-wtn/information-location).

Specific Actions

This section provides updates on the Company's supply- and demand-side resource actions taken over the past two-year period. As discussed below, the Company has procured substantial non-emitting and renewable resources and taken significant steps to improve or expand its demand-side resource programs and opportunities.

Supply-Side Resource Actions

The 2020AS RFP has concluded with the procurement of 1,792 MW of wind resources, 495 MW of solar additions, and 200 MW of battery storage capacity paired with solar. All of these resources have 2024 or 2025 CODs and will contribute to PacifiCorp's renewable energy and carbon reduction goals.

PacifiCorp procures for its system needs across its six-state territory. Prior to the passage of CETA and with the 2020 procurement effort, there were no cost-competitive Washington bids and therefore limited alignment with the CBIs that resulted from a 2021 stakeholder engagement process.

Following the 2021 IRP filing, PacifiCorp issued its first request for proposal to take into consideration the requirements of CETA. The ongoing 2022 all source request for proposals (2022AS RFP) was filed in Washington and received approval in three states after a lengthy stakeholder process. It was subsequently issued to the market on April 29, 2022. PacifiCorp hired an independent evaluator (IE) to oversee the process, with the oversight of the Washington Commission. In December 2022, PacifiCorp bid twelve eligible self-build (benchmark) resources into the 2022AS RFP, and on March 14, 2023, PacifiCorp received 302 bids from 74 developers and 93 different projects sites across six states. A final shortlist is expected to be released by late Q2 2023 or early Q3 2023, with resources contracted by the end of Q4 2023. PacifiCorp will consider its Washington CBIs before making a final shortlist decision.

Demand-Side Resource Actions

Since the original CEIP filing, PacifiCorp has made the following changes and updates to demand-side resource programs to help increase benefits to named communities and achieve goals informed by our Equity Advisory Group (EAG):[18]

Residential Energy Efficiency

- Enhanced incentives for windows in multi-family units on residential rate schedules. Initial focus on buildings in highly impacted communities.
- Continued direct install residential lighting in multi-family units with focus in highly impacted communities.

[18] These changes and updates were identified as CEIP Utility Actions in the 2022-2023 DSM Business Plan filed with the 2022-2023 Biennial Conservation Plan on November 1, 2021 (Docket UE-210830). The same actions were included in the CEIP, and the 2023 Annual Conservation Plan filed November 15, 2022 (Docket UE-210830), included an update on the Utility Actions.

- Maintained and expanded general purpose lamp buy down in “dollar stores” in highly impacted communities.
- Continued manufactured home direct install duct sealing and lighting. Continue focus in highly impacted communities.
- Continued promoting new construction offerings for multifamily, and single family units. Continue focus in highly impacted communities.
- Develop pathways for non-electric, non-natural gas upgrades in named communities.
    - Serve named community residential customers who use non-electric and non-natural gas fuel sources in their primary heating systems by offering incentives for decommissioning these systems and installing ductless heat pumps.

Low Income Weatherization

- Increased funds available for repairs from 15 percent to 30 percent.
- Permitted installation of electric heat to replace permanently installed electric heat, space heaters or any fuel source except natural gas with adequate combustion air as determined by the Agency. The changes are designed to promote the installation of electric heat and minimize use of wood heat, solid fuels or natural draft equipment in specific applications where combustion safety (and indoor air quality) cannot be maintained.

Non-residential energy efficiency

- Increased outreach and participation for small businesses and named community small businesses identified by census tract and rate schedule.
    - Created a new offer within the current small business enhanced incentive offer targeting the smallest businesses using less than 30,000 kilowatt-hours per year and Named Community small businesses on Schedule 24.
    - Targeted a portion of company initiated proactive outreach to small businesses located in highly impacted communities. Continued to tie proactive outreach to approved small business vendor capacity to respond to customer inquiries.
- Offered approved small business lighting vendors a higher vendor incentive for completed lighting retrofit projects with small businesses located in highly impacted communities.
- For 2023, the program seeks to create a new offer within the current small business offer to include enhanced incentives for select non-lighting measures.
- Continue development of program materials in Spanish and increase outreach to Latinx and Tribal community groups.

Specific to energy efficiency actions, the company will document its progress regarding the CBIs and energy savings targets in its annual clean energy progress report filed on July 1st each year

Specific to energy efficiency targets, PacifiCorp filed its 2023 Annual Conservation Plan on November 15, 2022 (Docket UE-210830). This plan includes an updated forecast for 2022-2023 which indicates a shortfall relative to the two-year target established via the process for target setting established by the Energy Independence Act (WAC 480-109-100). The final results for 2022-2023 will be in PacifiCorp’s Biennial Conservation Report due June 1, 2024. On November 1, 2023, PacifiCorp will file its Biennial Conservation Plan with the targets for 2024-2025. Those targets will be based on updated information relative to the CEIP and will align with those accepted from this ongoing two-year Energy Independence Act target setting process.

PacifiCorp also has also taken actions to develop demand response resources to work towards stated interim targets. Since the original CEIP, PacifiCorp received approval for Schedule 106, which is an enabling demand response tariff that supports multiple market driven programs. Schedule 106 provides a regulatory framework that includes a fast and flexible change process while at the same time enabling transparent customer information for the benefit of all stakeholders. Each new demand response program will use Schedule 106 for enablement, communication, and tracking. The Company has taken the following program-specific demand response actions in Washington:

Commercial and Industrial Curtailment
A commercial and industrial program was approved and effective in December 2022. The program focuses on enrolling connected end use loads available during various dispatch periods. Event communication and control occurs through a Program Administrator-provided, two-way communications device (communicating via cellular signals) installed at the customer site.

Irrigation Load Control
This program was approved and became effective in August 2022. It focuses on enrolling agricultural irrigation pumps with the highest connected loads during the available dispatch hours in the summer during the irrigation season with incentives differentiated based on dispatch notification option. The program relies on field-installed direct load control (DLC) devices to send signals to pumping equipment for reduction of irrigation loads for participating customers.

Bring your own Thermostat and Water Heater Direct Load Control
The company is preparing to file, for approval, a program to deliver curtailable end-use loads from residential HVAC equipment communicating through customers' web-enabled thermostats and electric water heaters via Wi-Fi enabled communication devices. The Company is currently estimating an effective date in 2023 for this program.

Batteries
This program is under consideration and is currently in the preliminary stages of planning. The program would potentially target residential – and possibly commercial – customers who have Wi-Fi connection to incentivize the use of individual batteries for system wide-integration in support of overall grid management.

While the Company has made progress on these demand response actions since filing the CEIP, as described above, program implementation is just beginning to ramp up. As noted in the CEIP, "Total demand response volume is subject to change based on timing of programs and contract negotiations."[19] As implementation and development of these new programs continues, progress toward and change to the interim targets will likely occur as expectations regarding demand response volumes are informed by actual effective program dates, leading to improved planning

[19] See CEIP page 22.

estimates. Volumes attained by the end of the CEIP period, 2025, will likely be different from the initial CEIP forecast of 37.4 MW.

Specific to demand response actions, the company will document its progress regarding the CBIs and capacity savings targets in its annual clean energy progress report filed on July 1st each year.

Time-of-Use Pilots
Beginning in May 2021, PacifiCorp launched residential and non-residential service time of use pilots. The residential pilot (Schedule 19) targets single family residential customers and is available for up to 500 customers on a first-come, first-served basis. The non-residential time of use pilot (Schedule 29) targets non-residential customers with loads under 1,000 kW and is available for up to 100 customers on a first-come, first-served basis.

Incremental Cost

An update to the incremental cost calculation is provided for the remaining years in the CEIP period, 2023 – 2025. The CEIP portfolio, W-10 CETA, was specifically optimized and designed to meet CETA standards. This portfolio is contrasted to the alternative lowest reasonable cost portfolio as defined in rule and is denoted P-SC or referred to as the Alternative Portfolio.[20] Any differences in cost between the CEIP portfolio and the Alternative Portfolio are considered incremental costs, costs directly resulting from actions taken to comply with requirements under RCW 19.405.040 or 19.405.050. These incremental costs include items like CETA-driven impacts to electricity generation, energy efficiency, new programs to support customers, and program management, that can be measured for the current CEIP period.

The methodology to calculate the updated incremental cost is consistent with the methods described in the refiled 2021 CEIP. Only the modeled IRP-based costs were updated at this time. Given the updated portfolio outcomes, the incremental costs to comply with CETA is $2.13 million on average per year.

Interim Target Shortfall Resolution

To develop the CEIP portfolio, the base portfolio, P-SC, was evaluated against CETA requirements that Washington-supplied energy would be 100% greenhouse gas neutral with up to 20 percent of this amount supplied by unbundled RECs beginning in 2030, and 100 percent clean and non-emitting by 2045.

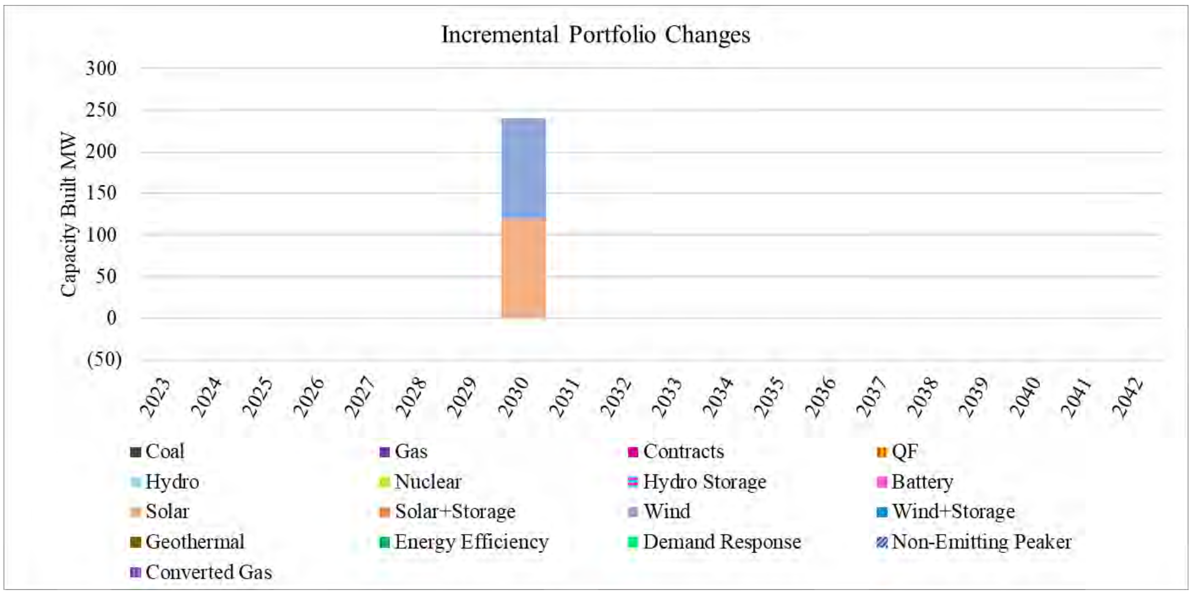
Given the system optimized portfolio under the SCGHG price policy assumption and assumed resource allocations to Washington customers, the Company identified a small compliance shortfall in 2030 and 2031. In years 2032 and beyond, the portfolio resources generated enough renewable and non-emitting energy to Washington to meet 100 percent of need. These compliance shortfalls were identified by calculating the amount of additional renewable or non-emitting energy that would be needed to meet at least 80 percent of Washington retail sales.

[20] Several portfolios were developed specific to Washington CETA legislation and are defined in Volume I, Chapter 8.

A compliance shortfall of 67 MW of average annual capacity was identified in 2030, and a slightly larger shortfall of 72 MW average annual capacity resulted for 2031.

To reach the target of at least 80 percent non-emitting energy in 2030-2031 at least-cost, and without the need for additional transmission lines, small-scale renewable capacity was added in Yakima, Washington. Specifically, 120 MW of installed capacity of small-scale solar and 120 MW of installed capacity of small-scale wind was added in Washington in 2030. The incremental small-scale resources were added only for CETA-compliance, on top of an optimized system portfolio developed under the SCGHG price policy assumption, as shown in Figure O.2. Thus, the incremental small-scale solar and wind was allocated situs to Washington and would represent an incremental cost in 2030 and 2031.

Figure O.2 - Incremental Portfolio Change: W-10 CETA delta P-SC



These incremental actions resulted in the CEIP-compliant portfolio, W-10 CETA, and the associated interim targets and incremental costs.

Revenue Requirement Methodology

Incremental costs included for consideration in this CEIP can be broadly considered in two categories – IRP modeled incremental costs, and non-IRP modeled incremental costs. IRP modelled incremental costs were identified through the comparison of changes in investment costs between the CEIP portfolio and the Alternative Portfolio, described above, for the years 2023 - 2025. Per rule WAC 480-100-660(1), the only differences in investment decisions between the two portfolios described are a direct result of CETA requirements, determined to be met in a least-cost least-risk manner. Incremental investments and expenses were identified from the comparison of the two portfolios and summarized on an annual, nominal and levelized basis for the remaining compliance years in the CEIP. Table O.2 summarizes the resource-driven incremental expenses identified. However, note that the column for 2022 was not updated and is equivalent to the modeled incremental cost shown in the Company's current CEIP.

Table O.2 - Annual Modeled Impacts of CETA

	Compliance Year			
($million)	**2022**	**2023**	**2024**	**2025**
Fuel Costs	-	(0)	0	(1)
Other Variable	-	0	0	0
Energy Efficiency	-	-	0	-
Net Market Purchases	-	(0)	(0)	(3)
Emissions	-	1	0	2
Deficiency	-	-	(0)	(0)
Fixed Costs	-	-	(0)	0
Total	**-**	0	(0)	(2)

There are no incremental resource additions in the CETA-compliant portfolio during the CEIP compliance window. Any differences in the annual modeled costs over the period are due to negligible movements in dispatch.

It is assumed that other non-modeled costs, as presented previously in the revised 2021 CEIP, have not changed and are shown in Table O.3.

Table O.3 - Non-modeled Impacts of CETA ($million)

CETA Expenses	2023	2024	2025	Description of Cost Item
CEIP Management, Coordination & Communication	0.57	0.58	0.60	Additional Staffing to help coordinate, facilitate and strategic planning for CEIP
Enhanced Outreach & Communication	0.39	0.39	0.40	Outreach and materials for EAG and Public meetings
External Data Support	0.17	0.18	0.18	Vendor expense for data support
CETA-specific DSM Program Expenses	1.26	1.29	1.32	Costs incurred to enhance reach and equitable distribution of DSM programs
Total	**2.40**	**2.45**	**2.50**	

Taking the estimated incremental costs identified based on methodologies described in this report, the company calculated an annual revenue requirement using the standard revenue requirement formula:

Revenue Requirement = Rate of Return x (Net Rate Base) + Operating Costs

Using the above formula, the estimated annual revenue requirement for the remaining years in the compliance period is as follow, presented in Table O.4.

Table O.4 - Revenue Requirement of Cost Estimates

	Compliance Year			
$-Millions	**2022**	**2023**	**2024**	**2025**
Revenue Requirement				
Fixed Costs[1]	-	-	(0.00)	0.00
Variable Costs				
Fuel Costs	-	(0.03)	0.03	(0.68)
Variable O&M	-	0.00	0.01	0.04
Energy Efficiency	-	-	0.00	-
Net Market Purchase	-	(0.04)	(0.12)	(3.11)
Emissions	-	0.54	0.10	2.16
Deficiency	-	-	(0.07)	(0.06)
Total Variable Costs	-	0.47	(0.04)	(1.64)
Administrative & General				
DSM Program Costs	1.24	1.26	1.29	1.32
Outreach Costs	0.40	0.37	0.38	0.39
Materials	0.01	0.01	0.01	0.01
Staffing	0.56	0.57	0.59	0.60
Data Support	0.17	0.17	0.18	0.18
Total Revenue Requirement [2]	**2.38**	**2.86**	**2.40**	**0.86**
Average Revenue Requirement	**2.13**			

Notes:
[1.] Incremental fixed cost are identical between the CEIP portfolio (W-10 CETA) and Alternative Portfolio (P-SC) during the CEIP compliance window. Fixed costs are reported in the respective portfolios at a nominal and levelized basis, which reflects both a return on and return of component.
[2.] Estimated revenue requirement is calculated based on incremental costs derived by comparing IRP portfolios. Actual cost recovery will ultimately be determined by the prevailing cost allocation methodology approved in Washington at the time recovery is sought.

The annual threshold for Alternative Means of Compliance as stated and calculated in the Revised CEIP filed March 13, 2023, has not changed and is equal to $16,667 million. Thus, based on current forecasts, the estimated incremental costs identified for implementation of CETA from 2022 to

2025 are within the annual threshold amount. As such, the Company will not rely on RCW 19.405.060(3) as a means of alternate compliance to achieve CETA's requirements.

Public Participation

The Company has engaged in various activities to increase public participation in the Company's IRP and CEIP processes. These specific actions, outreach methods and timing, and addressing barriers to participation and internal stakeholder development are discussed below.

Specific Actions

The Company has taken the following actions to promote equity and engagement within its Washington service area. These include:

Formed Equity Advisory Group (EAG): The EAG was assembled in 2021 to help inform and advise the Company on the issues most important to the communities that PacifiCorp serves in Washington. The EAG comprises nine representatives from highly impacted communities and vulnerable populations within the Company's Washington service area, including Yakima, Yakama Nation, and Walla Walla. These members have expertise on equity-related topics, such as the health of vulnerable populations and programs for low-income customers. The EAG meets regularly and provides significant input on the Company's CBIs, metrics included in the CEIP, and how the Company plans and operates within its Washington service area.

Development of CBIs: Consistent with CETA, the Company is committed to ensuring that the benefits from the transition to clean energy are broadly shared and equitably distributed among all customers, with a specific focus on named communities. PacifiCorp has partnered with stakeholders and advisory groups, including the EAG, to identify the highest priority benefits to customers and identify potential barriers and burdens that may prevent some customers from receiving those benefits. These efforts have resulted in nine CBIs and associated weighting factors to evaluate the equitable distribution of benefits. This allows the Company to assess and monitor the impacts of each proposed program, action, and investment. In addition, the CBIs were included in the Company's most recent CEIP to inform utility action, focusing on the named communities that were identified within the Company's Washington service area.

Established Utility Actions within the CEIP: PacifiCorp committed to and made several changes to residential and non-residential customer energy efficiency programs to increase the focus on delivery of benefits to named communities. These utility actions were informed on input received from the EAG and CBIs. The same utility actions will be included in the 2022-2023 Biennial Conservation Plan, and updates for 2023 will be included in the 2023 Annual Conservation Plan. These utility actions include modifications to the low-income weatherization program that the Company filed on December 21, 2021. These changes included, but were not limited to, expanding tariff applicability for the installation of energy efficiency improvements. Funds available for repairs were also increased from 15 percent to 30 percent of the annual reimbursement on energy efficient measures and income guidelines were updated to be consistent with RCW 19.405.020(25). Before these changes, some income-qualified homes could not receive energy efficiency improvements due to the extent of critical maintenance needed before the energy efficiency improvements could be made.

Establish an Electric Vehicle (EV) grant program: PacifiCorp established EV programs detailed in PacifiCorp's Washington Transportation Electrification Plan. On May 20, 2022, PacifiCorp filed its 2022 "Washington State Transportation Electrification Plan" with the Washington Utilities and Transportation Commission under Docket UE-220359[21]. PacifiCorp supplemented its original filing with an addendum filed on September 28, 2022. This is PacifiCorp's first filed TEP since enabling legislation was enacted in 2019. The Commission acknowledged the plan on October 27, 2022, enabling PacifiCorp to begin development of the proposed programs in the TEP inclusive of a communities grant program, outreach and education program, and managed charging pilot program. These programs would broaden the previous EV programs by allowing for multiple project types to participate with benefits and preference targeted towards named communities. The overall goal is to provide exploratory programs that will help to plan, promote, or deploy electric transportation technology and projects within Named Communities. Looking ahead, PacifiCorp is working with its Equity Advisory Group and the Washington Utility and Transportation Commission and other stakeholders to review draft program and pilot application prior to filing in Q2 of 2023. PacifiCorp anticipates launch of program and pilots in Q3 of 2023.

Modified the Low-Income Bill Assistance Program: PacifiCorp's low-income bill assistance (LIBA) program was established in 2003. LIBA provides a tiered discount based on income levels. Previously, LIBA was designed to provide credits to income-eligible households on monthly usage over 600 kWh and included an annual enrollment cap. Consistent with the requirements in RCW 19.505.120 and consultation with the Low-Income Advisory Group, the Company proposed modifications to its program. In particular, the Company proposed to (1) increase the maximum income threshold for the program consistent with RCW 19.405.020(25), (2) modify the discount from a per kWh above 600 kWh, to a percentage discount of the net bill, with the discount level based on household size and income; and (3) eliminate the annual enrollment cap. These changes were allowed to go into effect on August 1, 2021.

PacifiCorp also hired Empower Dataworks to prepare a 2022 Energy Burden Assessment (EBA) for the Company's residential customers in Washington. In the EBA, Empower Dataworks highlighted that the LIBA program design is very good at targeting benefits to higher burden customers and program administration. It also noted that the overhead costs are very efficient relative to other programs in the state, and praised the great coordination between PacifiCorp and the local community action agencies on providing culturally appropriate marketing and program designs. PacifiCorp partners with three

[21] Materials available online at UTC Case Docket Document Sets | UTC (wa.gov)

agencies to administer and deliver the program: Blue Mountain Action Council (BMAC) serves Columbia, Garfield, and Walla Walla counties, Opportunities Industrialization Center of Washington (OIC) serves Upper Yakima County, and Yakima Valley Farm Workers Clinic dba Northwest Community Action Center (NCAC) serves Lower Yakima County.

Continued and Expanded Outreach

To ensure consistent outreach, PacifiCorp continues to use all of the engagement methods included in its CEIP, including PacifiCorp's CEIP and IRP dedicated website; email updates; fact sheet and flyers; bill inserts and bill messages; interactive voice response; social media, paid and press media; text message notices; partner channels; community surveys; CEIP Public Meetings and Technical Conferences; EAG Meetings; existing advisory groups and EAG pre-meeting materials; and meeting summaries.

These engagement methods attempt to further facilitate durable community relationships. Examples of specific continued outreach include:

- PacifiCorp's Washington EAG began meeting in 2021 and has continued to hold meetings to, in part, support CEIP development and implementation. These meetings have continued into 2023, and have offer in-person and virtual meeting opportunities throughout the year;
- PacifiCorp's initial public participation outreach included both telephone and email and was designed to inform existing advisory groups (including the IRP Public Input Process) of the opportunity to provide feedback, as well as to form the Washington EAG;
- PacifiCorp continues to utilize its Washington Clean Energy Transformation Act & Equitable Distribution of Benefits webpage and the Integrated Resource Plan webpage to provide information to the public regarding how to participate in meetings, the development of the CEIP and the development of the IRP;
- PacifiCorp's outreach for both the DSM Advisory Group and the Low-Income Advisory Group continues to occur by email to participants on the distribution list; and
- The company has set up a dedicated email address, CEIP@pacificorp.com, that is posted on the webpage to facilitate timely responses to any stakeholder questions. Additionally, PacifiCorp encouraged members of the public who wanted to participate in the development of the CEIP to join the company's email list, which was used to communicate upcoming meetings, meeting materials, and other opportunities for education and feedback.

In addition to continued outreach, the Company has expanded its Public Participation outreach methods to draw in more diverse customer interests. For example:

- PacifiCorp developed a survey that targets our broader Washington customer base to gather input on the development of the CEIP. The survey was made available in English and Spanish between July 2, 2021, and August 10, 2021. There were separate versions for residential and non-residential customers. Survey results were prepared, summarized, and posted on the Washington Clean Energy Transformation Act & Equitable Distribution of

Benefits webpage. Customer feedback was incorporated into the Customer Benefit Indicator (CBI) weighting process. PacifiCorp continues to explore methods to improve these surveys, and plans to use similar outreach methods in 2023.
- PacifiCorp held 3 technical conferences on the CEIP development process that were targeted for parties interested in a deeper examination of the CEIP. PacifiCorp is open to additional CEIP technical conferences.

The Company welcomes continues to explore—and welcomes helpful suggestions—for expanded public participation methods for future CEIP planning cycles.

Addressing Barriers to Participation

The Company continues to address barriers to participation, and support inclusion and accessibility in the Company's CEIP and IRP planning processes. For example PacifiCorp:

- Now offers hybrid meeting formats for its EAG meetings, where members can attend meetings online or in-person. Initially, the COVID-19 pandemic prevented in-person gatherings from taking place, making virtual meetings necessary. Over time, the need for virtual meeting formats lessened, giving the group space to explore other ways to connect, and various stakeholders expressed an interest for in-person meeting options as well. PacifiCorp held its first hybrid meeting for the Washington EAG in March 2023. The majority of the participants attended in person. The company intends to continue to offer a mix of online and in-person meeting options in the future.
- Continues to offer Spanish translation of meeting materials, and have interpreters present at public participation meetings.
- Continues to seek input from the EAG and public to foster inclusion, equity, and continuing to learn about the ways that the company can better communicate to meet the cultural needs of its communities.
- Continuing to ensure that information is available in broadly understood terms for all in the community, and ensuring that customers have access to information through various accessible formats.
- Has continued engagement with its on-going EAG, and stakeholders interested in the CEIP development process.

These actions to address barriers to participation help PacifiCorp identify specific actions that support initiatives to improve health, safety, and well-being of its communities, and PacifiCorp continues its CEIP public participation process to ensure open, transparent, and accessible processes.

Internal Stakeholder Development

PacifiCorp is also making efforts to promote equity through internal stakeholder development. To achieve results in this arena, PacifiCorp is developing and equipping internal stakeholders with adaptive leadership skills, education to build intercultural competency, and access to a devoted core team supporting an equity lens on stakeholder engagement. This has included:

- **Outside subject matter expertise and facilitation**. The Company has engaged E Source as its stakeholder facilitator and content support developer, who acts as an accountability partner for internal stakeholder development. This accountability allows a value chain that creates and strengthens our internal equity decision-making lens and ensures that it bears fruit in our deliverables and stakeholder engagement, and this consequently will help achieve equitable results in the communities the Company serves.

- **Building adaptive leadership skills**. The Company held an adaptive leadership in equity workshop for key PacifiCorp employees who work on external engagement and customer and community solutions. This workshop was held in December 2022 and focused on acknowledging and finding agreement on the value of building a safe and supportive space to grow individual's adaptive leadership skills and provide tools, resources, and guidance in our shared journey. This workshop is important because developing an equity decision-making lens requires understanding and acceptance on the individual and corporate level of intercultural competency. Further, it requires a commitment to self-awareness, learning, application (success and lessons learned), and growth.

- **Building intercultural communication skills**. The Company plans to host an internal workshop in the spring of 2023, that will equip its employees with the tools necessary for effective intercultural communication. While it is expected that most subscribe to the Golden Rule – do unto others as you would like done unto you – in communications, this stops short of intercultural competency. The golden rule is based on a monocultural worldview and assumes all groups value the same thing. This workshop aims to support trust building and the adaption of individual perspective and behaviors to connect better, communicate and engage others.

- **Benchmarking and building intercultural competency.** The Company will administer the Intercultural Development Inventory (IDI) Survey, considered an international benchmark, in the fall of 2023. Core team members will be debriefed privately on their scores and given individual development and coaching plans

APPENDIX P – ACRONYMS

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

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

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 = international organization for standardization / 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

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

LRA = Local Regulatory Authority

LSE = load serving entities

MATS = Mercury and Air Toxics Standards

MEHC = MidAmerican Energy Holdings Company

MMBpd = Million barrels of oil per day

MMBtu = Million British thermal units

MSP = Balancing Authority Area / 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

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 / Operations Mapping 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

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)

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) / Rural Electric Cooperative

RFI = request for information

RFM = Rate Forecasting Model

RFP = Request for Proposal

RH = Relative humidity

RICE = Reciprocating Internal Combustion Engine

RMP = Rocky Mountain Power / Resource Management Plan

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 / Sarbanes-Oxley Act

SRSG = Southwest reserve sharing group

SSR = supply side resource (table)

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

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