PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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October 18, 2019

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

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

Attn: Filing Center

RE: LC 70—PacifiCorp's 2019 Integrated Resource Plan

Enclosed please find twenty copies of PacifiCorp's 2019 Integrated Resource Plan (2019 IRP). The 2019 IRP is also available electronically on PacifiCorp's IRP website, at: www.pacificorp.com/energy/integrated-resource-plan.html.

As with the 2017 IRP, PacifiCorp will provide data discs for the 2019 IRP. These discs provide support and additional details for the analyses included in the 2019 IRP. The company plans to supplement this filing by October 25, 2019, to distribute the data discs, which will contain both non-confidential and confidential work papers.

PacifiCorp submits the 2019 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.

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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
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PacifiCorp appreciates the time and effort Oregon participants have dedicated to helping the company develop its 2019 IRP.

Informal inquiries may be directed to Cathie Allen, regulatory affairs manager at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

cc: Service List LC 67 (without enclosures)

CERTIFICATE OF SERVICE

I certify that I filed a true and correct copy of PacifiCorp's **2019 Integrated Resource Plan** on the parties listed below via electronic mail and/or overnight delivery in compliance with OAR 860-001-0180.

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Dated October 18, 2019.

Katie Savarin
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I certify that I electronically filed a true and correct copy of PacifiCorp's **2019 Integrated Resource Plan** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated October 18, 2019.

Katie Savarin
Coordinator, Regulatory Operations

2019 Integrated *resource plan*

VOLUME I

OCTOBER 18, 2019

This 2019 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Marengo Wind Project
Transmission Line
Electric Meter
Pavant III Solar Plant

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CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp's 2019 Integrated Resource Plan (IRP) was developed through comprehensive analysis and a public-input process spanning nearly a year and a half resulting in the selection of a least-cost, least-risk preferred portfolio. The 2019 IRP preferred portfolio includes accelerated coal retirements and investment in transmission infrastructure that will facilitate adding over 6,400 megawatt (MW) of new renewable resources by the end of 2023, with nearly 11,000 MW of new renewable resources over the 20-year planning period through 2038.[1] The 2019 IRP preferred portfolio advances PacifiCorp's long-term vision as described in the following section.

PacifiCorp's Vision

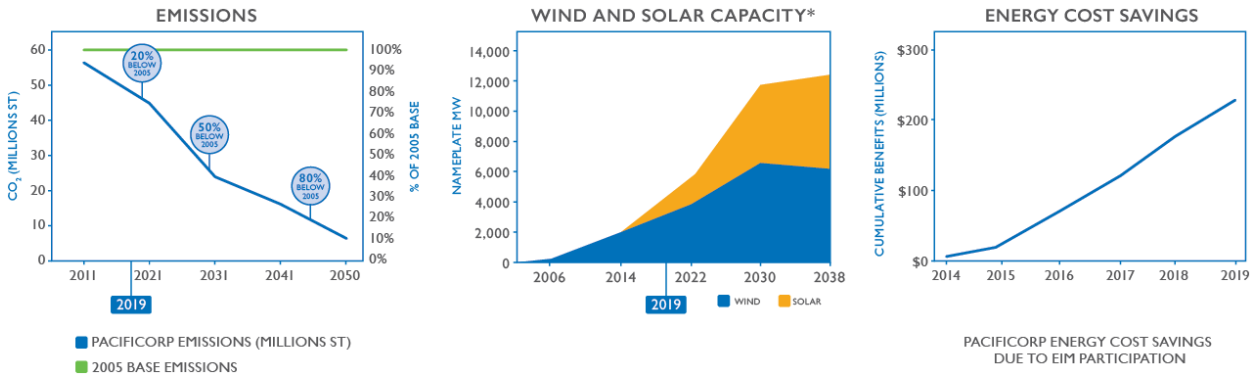
PacifiCorp shares a bold vision with our customers for a future where energy is delivered affordably, reliably and without greenhouse gas emissions. A future where our vast, modern energy grid connects local communities to the low-cost and reliable energy they need to innovate and achieve their goals. PacifiCorp believes that affordability and sustainability go hand in hand and together, they form the foundation for a reliable, resilient energy future—where regional and state economies benefit from investments in energy resources and infrastructure that help them pioneer new growth opportunities. It is an ambitious vision, but it is absolutely achievable. By connecting the West's diverse resources to the vast reach of our transmission system and by investing in technology, partnerships and markets, PacifiCorp is positioned to create the future our customers and communities seek.

Reimagining the Future Based on a Century of Innovation

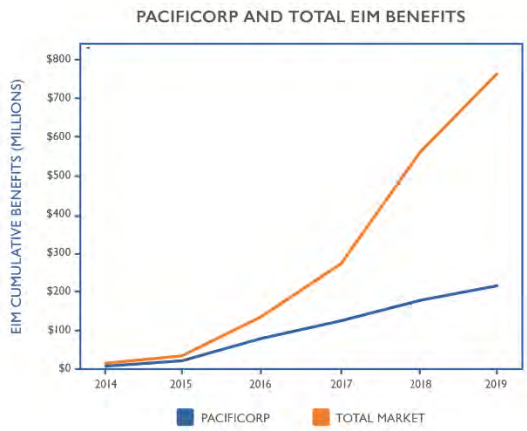
When PacifiCorp joined Berkshire Hathaway Energy in 2006, the company set out to be the best energy company in terms of service to its customers while delivering sustainable energy solutions. The path forward was viewed as an invitation to reimagine not just how energy is produced but how it is dispatched and delivered. It was clear that PacifiCorp's greatest opportunity would be discovered in understanding the needs and aspirations of its customers and communities. The company saw the West itself, with its abundance of diverse natural resources, as a way to deliver greater value. And believed that the greatest gains could be realized by building upon the more than 100 years of innovation that helped create PacifiCorp's ten-state energy grid. By drawing on its track record of partnership and technology-driven innovation, PacifiCorp could transform its expansive grid into an industry-leading, interconnected energy system—a system uniquely equipped to access the best energy resources the West has to offer and efficiently deliver those resources to customers and communities across the region.

PacifiCorp has made significant progress over the past 13 years, becoming the largest regulated utility owner of wind power in the West. From 2018 to 2020, PacifiCorp will have increased the percentage of zero-carbon energy resources in its portfolio by 70 percent. The company made sure to do it all while capturing and returning savings to its customers.[2]

[1] Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.
[2] *Id.*



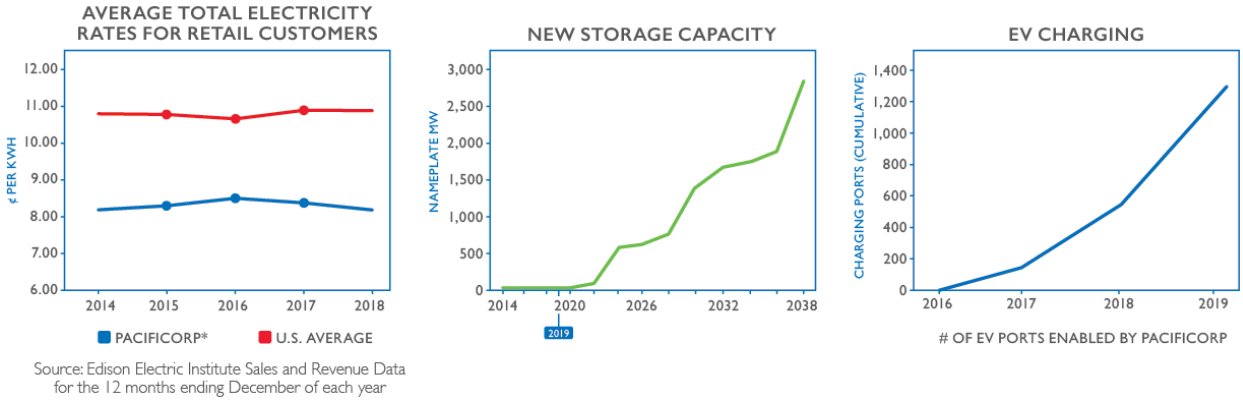
Reinventing the Future through Collaboration



Over the past 13 years, PacifiCorp has successfully reduced its carbon emissions and improved reliability while simultaneously delivering energy cost savings to its customers. These results have been achieved by collaborating with others to create a more open and connected Western grid and through the visionary and collaborative efforts of PacifiCorp's own generation, transmission, information technology and energy supply management teams. In 2014, PacifiCorp pioneered the Western Energy Imbalance Market (EIM) in partnership with the California Independent System Operator. This innovative market allows utilities across the West to access the lowest-cost energy available in near real time, making it easy for zero fuel-cost renewable energy to go where it is needed. If excess solar energy in California, excess wind from Wyoming or hydropower from Washington and Oregon is available, PacifiCorp will harness it and transport it instantly across the company's 16,500-mile grid.

Through participation in the EIM, PacifiCorp has saved its customers over $200 million so far. The savings get bigger every year, and the company has reduced its portfolio carbon emissions over 15 million tons—the equivalent of taking 3 million cars off the road for a year.

Since its inception, nine utilities have joined the EIM and 11 more have committed to join by 2022, altogether representing almost 70 percent of the West's total electricity demand. As more participants join the EIM, the benefits increase. To date, participating utilities across the West have saved customers over $730 million while simultaneously decarbonizing the Western grid. PacifiCorp continues to engage new partners in evolving the real-time EIM to include a day-ahead market for even bigger future benefits.



Rethinking the Future by Investing in the Diversity of the West

PacifiCorp continues to offer its customers some of the lowest energy prices in the country—well below the national average—while simultaneously expanding the depth and breadth of its energy portfolio and solutions.

- **Energy Vision 2020**: In 2017, PacifiCorp announced its largest historical investment in the development of renewable energy and infrastructure—Energy Vision 2020. This $3 billion project to be completed in 2020 embodies the company's commitment to a future that benefits its customers, its communities and the environment. It will dramatically increase PacifiCorp's renewable energy portfolio with new and repowered wind resources and new transmission while leveraging federal production tax incentives to provide hundreds of millions of dollars in savings to its customers over the life of the projects. Energy Vision 2020 also benefits rural communities across the West by creating hundreds of construction jobs and adding millions of dollars in construction tax revenue and ongoing annual state and local tax revenue.

- **Proposed New Resource Investments**: PacifiCorp's 2019 IRP sets forth a plan to expand its resource portfolio with new low-cost wind generation, solar generation and storage to meet changing customer needs.[3]

Resource	Through 2023	Through 2038
Wind (ID, UT, WA, WY)	Over 3,500 MW	Over 4,600 MW
Solar (ID, OR, UT, WA, WY)	Nearly 3,000 MW	Over 6,300 MW
Storage (ID, OR, UT, WA, WY)	Nearly 600 MW	Over 2,800 MW

Innovating Solutions to Build the Future

- **Demand Response**: PacifiCorp is championing technical innovations that use fast-acting residential demand response resources to support the bulk power system. PacifiCorp's approach moves beyond peak-load management to create a grid-scale solution that turns demand response resources into frequency-responsive operating reserves. With over 92,000 customers participating in this program, more than 200 MW of operating reserve is available every day and can be dispatched in a matter of seconds. This reduces PacifiCorp's

[3] *Id.*

need to supply operating reserves with higher cost alternatives, and it is only used in emergencies, minimizing inconvenience to customers.

PacifiCorp is also partnering with The Wasatch Group to develop and manage a first-of-its-kind residential battery demand response solution. This new all-electric apartment building in Utah features on-site energy storage for each of its 600 units, totaling 12.6 MWh of solar-powered battery storage. This innovative all-electric design provides emergency back-up power to residents, helps address air quality issues in the area and benefits overall electric grid operation.

- **Customized Renewable Energy Solutions**: PacifiCorp is partnering with communities and customers across the West to champion customized energy solutions to achieve their renewable energy goals. For example, the company's work with Facebook is resulting in the construction of 677 MW of new solar and wind capacity, all in service by the end of 2020. These projects support Facebook's operations in Oregon, enabling it to achieve its 100% renewable goal while simultaneously lowering energy supply costs for all PacifiCorp customers. In addition, PacifiCorp secured 122 MW of new solar energy capacity on behalf of Facebook's data center in Eagle Mountain, Utah.

- **Electrification**: The electric transportation market is in an emerging state that represents a potential driver for future load growth, improved air quality, reduced greenhouse gas emissions, improved public health and safety, and creation of financial benefits for drivers, particularly for low and moderate-income populations. PacifiCorp is investing over $26 million to support electric vehicle (EV) fast chargers along key corridors, develop robust workplace charging programs, implement smart mobility programs and develop opportunities for customers in its rural communities. The company's investments include a $4 million partnership award from the U.S. Department of Energy to research and develop electric transportation primarily in Utah and $3 million as part of the Oregon Clean Fuels Program.

Bringing the Best of the West to PacifiCorp's Customers

PacifiCorp's 2019 IRP includes investments in diverse new resources like, renewables, storage and modern grid technology among them. It outlines new transmission infrastructure investments across our territory that are needed to remove existing transmission constraints and improve grid resilience so the lowest-cost renewable resources can flow freely to customers across the West.

PacifiCorp's IRP also provides the roadmap by which it will dramatically reduce its greenhouse gas emissions over the next 20 years. The IRP shows that, by 2030, PacifiCorp will have reduced greenhouse emissions by nearly 60 percent from 2005 levels. Along with adding renewables and leveraging new technology, emissions reductions will be achieved by the phased transition of its coal fleet.

PacifiCorp's thermal assets and operations teams have played an essential role in enabling the progress made to date, and the company recognizes the vital part that these resources play in their communities too. PacifiCorp is committed to open and transparent communication about our coal transition, and equally committed to working with our employees and communities to develop plans that help them through this time of change.

Connecting the West to More Value

PacifiCorp believes a path to reduced carbon emissions must be substantiated with a prescriptive and thoughtful plan. The company's plan revolves around three interrelated strategies to reimagine an energy future that serves all of its communities.

PacifiCorp sees the energy diversity of the West as a catalyst. The company's plans to meet the energy needs of its customers and communities across the West will continue to evolve, but PacifiCorp's commitment to making the West stronger and better is unwavering. PacifiCorp will achieve this by continuing to find answers in new partnerships, advanced technologies and expanded energy markets, and by pursuing energy solutions that harness and bring the best energy resources the West has to offer to its customers' door.

PacifiCorp's Integrated Resource Plan Approach

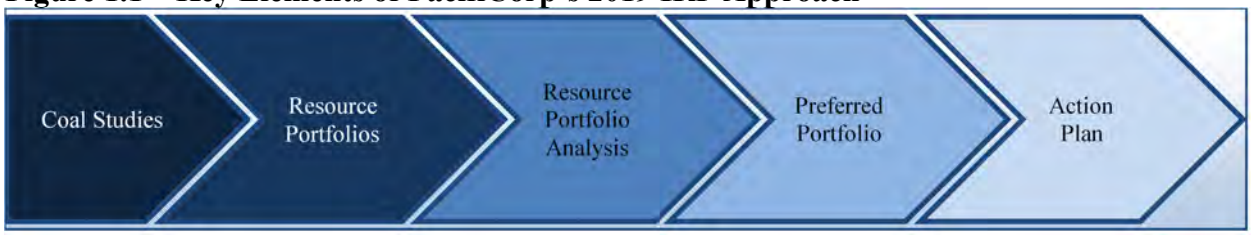
PacifiCorp has been making progress in its efforts to bring the best of the West to its customers, and PacifiCorp's 2019 IRP presents the company's plans to make significant advancements in this vision. The 2019 IRP sets forth a clear path to provide reliable and reasonably priced service to its customers. The analysis supporting this plan helps PacifiCorp, its customers, and its regulators understand the effect of both near-term and long-term resource decisions on customer bills, the reliability of electric service PacifiCorp customers receive, and changes to emissions from the generation sources used to serve customers. In the 2019 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency programs.

The primary objective of the IRP is to identify the best mix of resources to serve customers in the future. The best mix of resources is identified 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 2019 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 June 2018. Over the subsequent year and a half, PacifiCorp met with stakeholders in five states and hosted eighteen public-input meetings. 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 2019 IRP.

As depicted in Figure 1.1, PacifiCorp's 2019 IRP was developed by working through five fundamental planning steps that began with a comprehensive and robust analysis of its coal units. The narrow scope of the coal study, which focused on unit-by-unit analyses with prescriptive retirement timing assumptions, was never intended to inform retirement decisions, but rather to inform the more in-depth and refined analysis in the subsequent 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 that considers a wide range of potential coal retirement dates and other planning uncertainties. 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 informed selection of a 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 are also done to produce specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp's 2019 IRP Approach



Preferred Portfolio Highlights

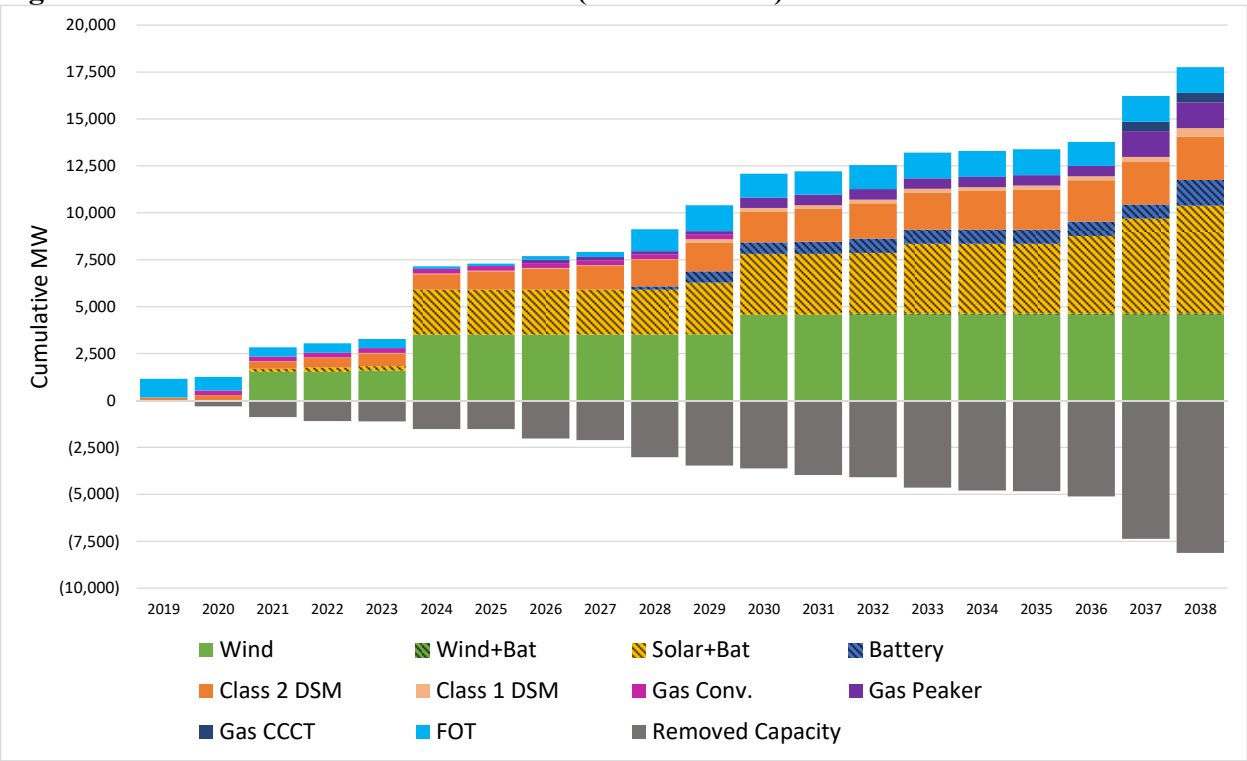
PacifiCorp's selection of the 2019 IRP preferred portfolio is supported by comprehensive data analysis and an extensive stakeholder input process, described in the chapters that follow. Figure 1.2 shows that PacifiCorp's preferred portfolio continues to include new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, and for the first time, significant battery storage resources. By the end of 2023, the preferred portfolio includes nearly 3,000 MW of new solar resources and more than 3,500 MW of new wind resources, inclusive of resources that will come online by the end of 2020 that were not in the 2017 IRP.[4] The preferred portfolio also includes nearly 600 MW of battery storage capacity (all collocated with

[4] *Id.*

new solar resources), and over 700 MW of incremental energy efficiency and new direct load control resources.

Over the 20-year planning horizon, the preferred portfolio includes more than 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, more than 2,800 MW of battery storage (nearly 1,400 MW of which are stand-alone storage resources starting in 2028), and more than 2,700 MW of incremental energy efficiency and new direct load control resources.[5] While the preferred portfolio includes new natural gas peaking capacity beginning 2026, this falls outside of the 2019 IRP action plan window, which provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain long-term system reliability.

Figure 1.2 – 2019 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes a 400-mile transmission line known as Gateway South, planned to come online by the end of 2023, that will connect southeastern Wyoming and northern Utah. The new transmission line is in addition to the 140-mile Gateway West transmission line in Wyoming currently under construction as part of PacifiCorp's Energy Vision 2020 initiative. The preferred portfolio further includes near-term transmission upgrades in Utah and Washington. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources. Table 1.1 summarizes the incremental transmission projects included in the 2019 IRP preferred portfolio, and Table 1.2 summarizes the total amount of initial capital investment required to deliver incremental transmission and resource investments through the 20-year planning period of the 2019 IRP.

[5] *Id.*

Table 1.1 – Transmission Projects Included in the 2019 IRP Preferred Portfolio*

Year	Resource(s)	From	To	Description
2023	69 MW Wind (2023) 231 MW Solar (2024)	Within Southern UT Transmission Area		Enables 300 MW of interconnection: UT Valley 345-138 kV + 138 kV reinforcement ($8m)
2024	354 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 1 ($0)
2024	674 MW Solar (2024)	Within Northern UT Transmission Area		Enables 600 MW of interconnection: Northern UT 345 kV reinforcement ($30m)
2024	1,920 MW Wind (2024)	Aeolus WY	UT North	Enables 1,920 MW of interconnection with 1,700 MW of TTC: Energy Gateway South ($1,752m)
2024	395 MW Solar (2024) 10 MW Wind (2029)	Within Yakima WA Transmission Area		Enables 405 MW of interconnection: local reinforcement ($3m)
2024	359 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 2 ($0)
2030	1,040 MW Wind (2030) 60 MW Wind (2032)	Goshen ID	UT North	Enables 1,100 MW of interconnection with 800 MW of TTC ($254m)
2030	500 MW Solar (2030)	Within Southern UT Transmission Area		Enables 500 MW of interconnection: UT Valley local area reinforcement ($206m)
2033	475 MW Solar (2033)	Within Southern OR Transmission Area		Enables 475 MW of interconnection: Medford area 500 kV-230 kV reinforcement ($102m)
2036	419 MW Solar (2036)	Yakima WA	Southern OR	Enables 430 MW of interconnection with 450 MW of TTC: Yakima WA to Bend OR 230 kV ($255m)
2037	909 MW Solar (2037)	Southern UT	Northern UT	Reclaimed transmission upon retirement of Huntington 1-2 ($0)
2037	443 MW Gas (2037)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement ($40m)
2037	370 MW Gas (2037)	Within Southwest WY Transmission Area		Enables 500 MW of interconnection: separation of double circuit 230 kV lines ($39m)
2038	702 MW Solar (2038)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 3-4 ($0)

*Note: 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.

Table 1.2 – Total Initial Capital to Deliver Preferred Portfolio Transmission and Resource Investments ($ million)

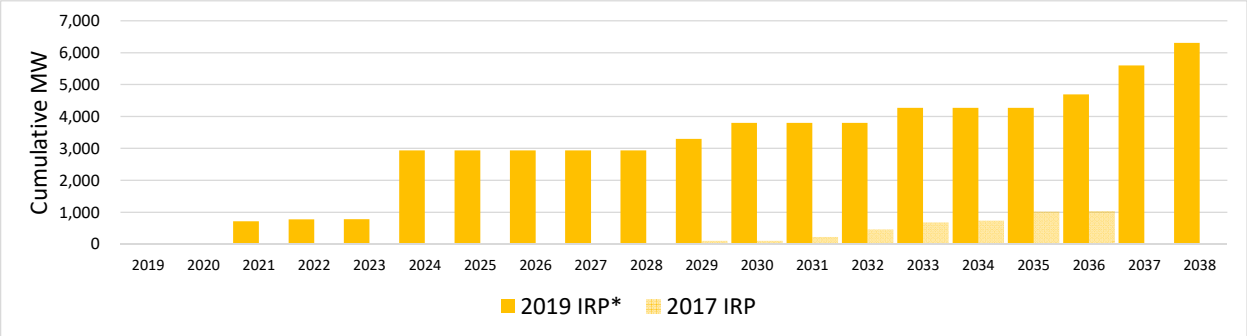
State	Transmission	Resources	Total
Idaho	$254	$1,659	$1,912
Oregon	$264	$2,540	$2,804
Utah	$1,004	$3,466	$4,470
Washington	$136	$1,509	$1,644
Wyoming	$765	$5,376	$6,141
Colorado	$370	$0	$370
Total	$2,792	$14,550	$17,342

New Solar Resources

The 2019 IRP preferred portfolio includes more than 3,000 MW of new solar by the end of 2023, which accounts for resources that will be online by the end of 2020 but not in the 2017 IRP, and more than 6,300 MW of new solar by 2038 as shown in Figure 1.3.[6]

[6] *Id.*

Figure 1.3 – 2019 IRP Preferred Portfolio New Solar Capacity*

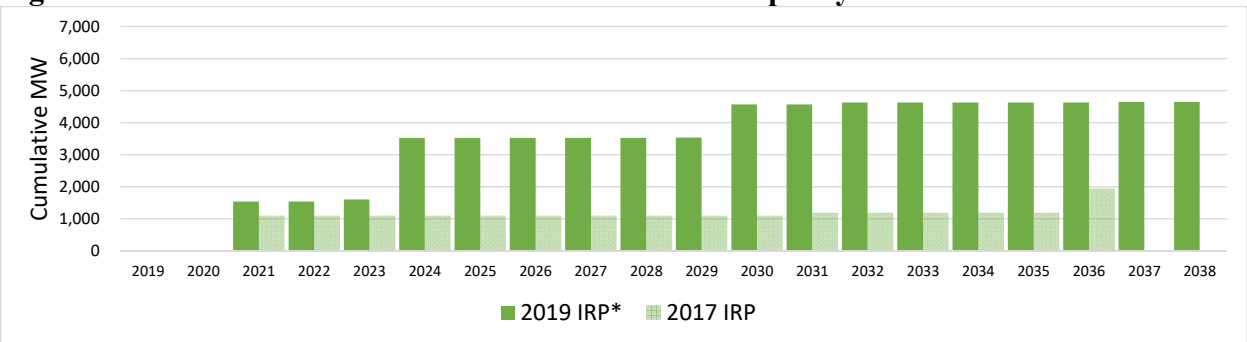


*Note: 2019 IRP solar capacity shown in the figure includes 559 MW of contracted new solar (all power-purchase agreements) that was not identified in the 2017 IRP. These resources will be online by the end of 2020 and are shown in the first full year of operation (the year after year-online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Wind Resources

As shown in Figure 1.4, PacifiCorp's 2019 IRP preferred portfolio includes more than 3,500 MW of new wind generation by the end of 2023, which accounts for new resources that will come online by the end of 2020 but not in the 2017 IRP, and more than 4,600 MW of new wind by 2038.[7]

Figure 1.4 – 2019 IRP Preferred Portfolio New Wind Capacity*



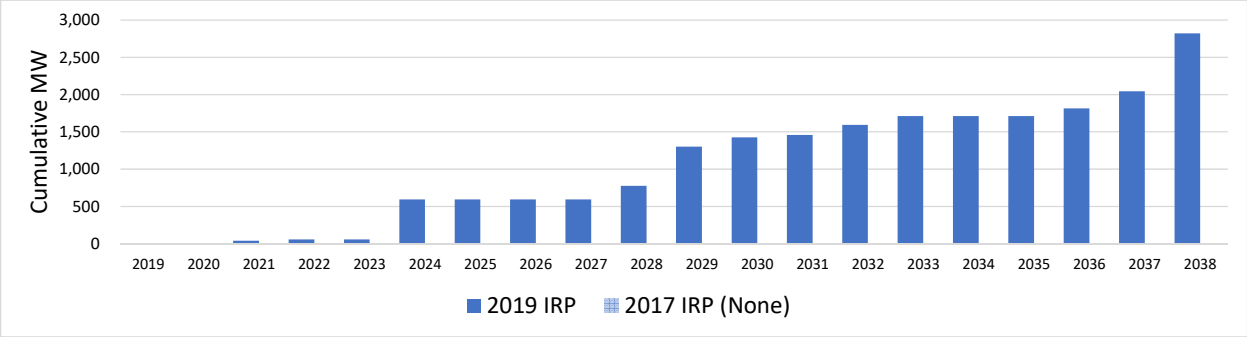
*Note: 2019 IRP wind capacity shown in the figure includes 1,533 MW of contracted new wind (21 percent power-purchase agreements) that was either identified in the 2017 IRP and is under construction or that was not identified in the 2017 IRP and is under contract. These resources will come on-line by the end of 2020. These resources are shown in the first full year of operation (the year after year-end online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Storage Resources

This is the first PacifiCorp IRP that identifies new battery storage resources as part of its least-cost, least-risk portfolio. As shown in Figure 1.5, PacifiCorp's 2019 IRP preferred portfolio includes nearly 600 MW of battery storage by the end of 2023. All of the storage resources planned through this period are paired with new solar generation. The plan also adds nearly 1,400 MW of stand-alone storage resources starting in 2028.

[7] *Id.*

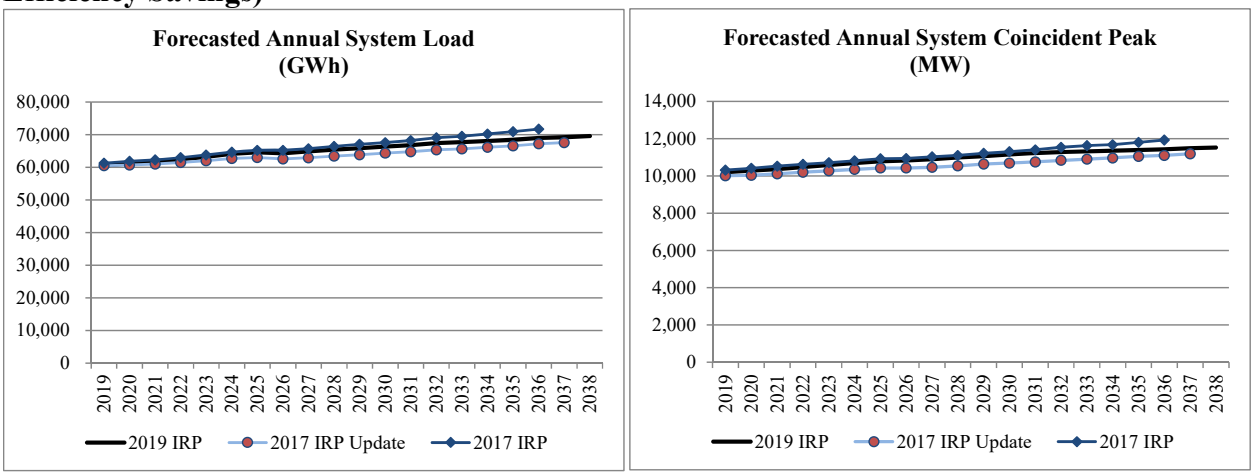
Figure 1.5 – 2019 IRP Preferred Portfolio New Storage Capacity



Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and direct load control 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 1.6 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2017 IRP and 2017 IRP Update. On average, forecasted system load is up 2.4 percent and forecasted coincident system peak is up 3.4 percent when compared to the 2017 IRP Update. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 0.73 percent for load and 0.64 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from data centers driving up the commercial forecast and an increase the residential forecast.

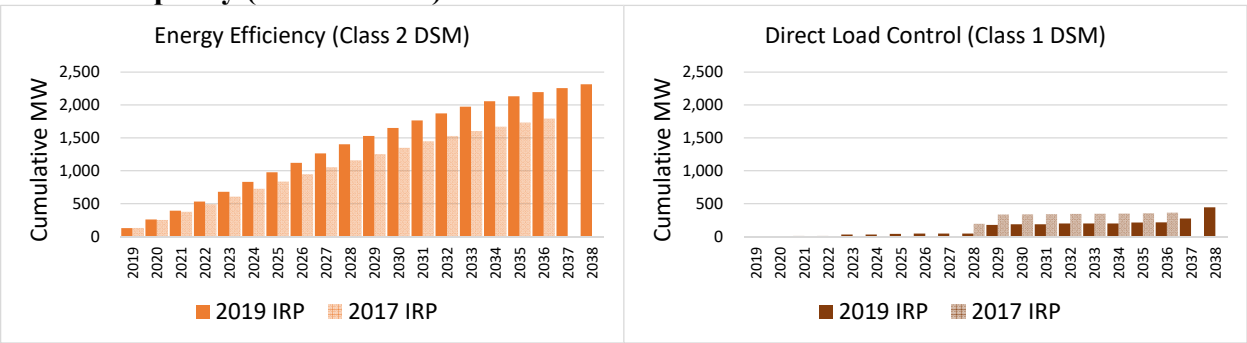
Figure 1.6 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 1.7 compares total energy efficiency savings in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio.

In addition to continued investment in energy efficiency programs, the preferred portfolio continues to show a role for incremental direct load control programs with total capacity reaching 444 MW by the end of the planning period. The chart to the right in Figure 1.7 compares total incremental capacity of direct load control program capacity in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio and does not include capacity from existing programs.

Figure 1.7 – 2019 IRP Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 1.8 shows that the 2019 IRP's base case forecast for natural gas and power prices has increased from those in the 2017 IRP and 2017 IRP Update. 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 2019 IRP are primarily driven by the assumption of a carbon price that is higher and starts earlier (2025) than what was assumed in the 2017 IRP Update (2030).[8] Moreover, the 2019 IRP assumed higher natural gas prices than either the 2017 IRP or 2017 IRP Update as Henry Hub, in particular, is boosted by increasing LNG exports. While not shown in the figure below, the 2019 IRP also evaluated low and high price scenarios when evaluating the cost and risk of different resource portfolios.

Figure 1.8 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

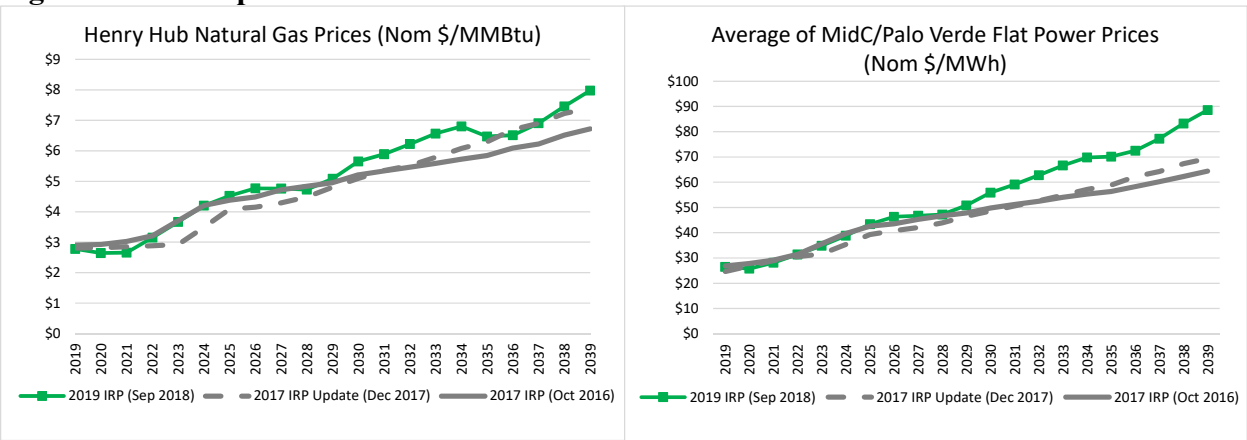
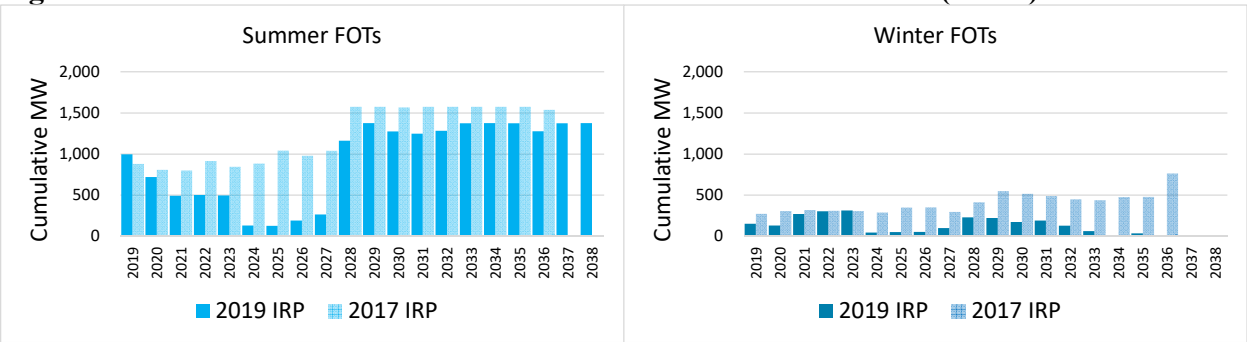


Figure 1.9 shows an overall decline in reliance on wholesale market firm purchases in the 2019 IRP preferred portfolio relative to the market purchases included in the 2017 IRP preferred portfolio. In particular, reliance on market purchases during summer peak periods averages 366

[8] The 2017 IRP did not assume a carbon price but, instead, reflected implementation of the Clean Power Plan.

MW per year over the 2020-2027 timeframe—down 60 percent from market purchases identified in the 2017 IRP preferred portfolio. This reduction in market purchases coincides with the period over which there are resource adequacy concerns in the region. While market purchases increase beyond 2027, 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.

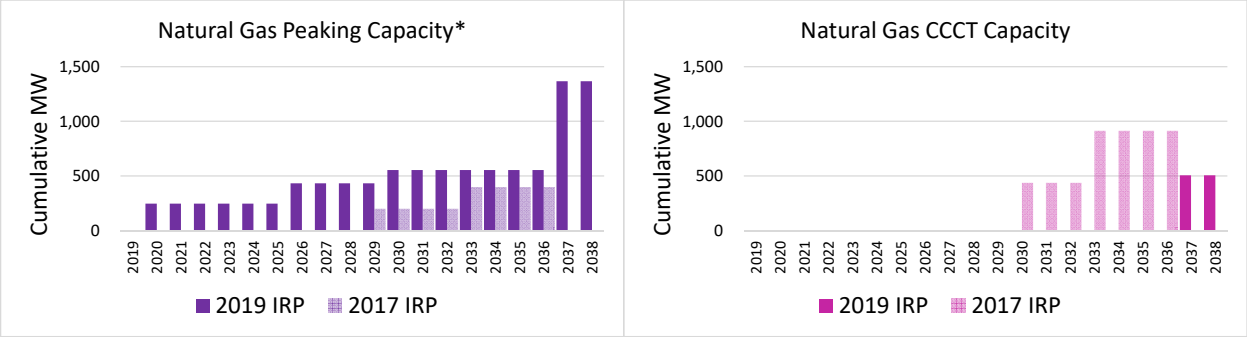
Figure 1.9 – 2019 IRP Preferred Portfolio Front Office Transactions (FOTs)



Natural Gas Resources

In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost resource to reliably serve our customers during peak-load periods. New natural gas peaking resources appear in the preferred portfolio starting in 2026, which is outside the action-plan window. This provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain system reliability long into the future.

Figure 1.10 – 2019 IRP Preferred Portfolio Natural Gas Peaking and Combined Cycle Capacity*



* Note: 2019 IRP natural gas peaking capacity includes the conversion of Naughton Unit 3 to natural gas in 2020 (247 MW).

Coal Retirements

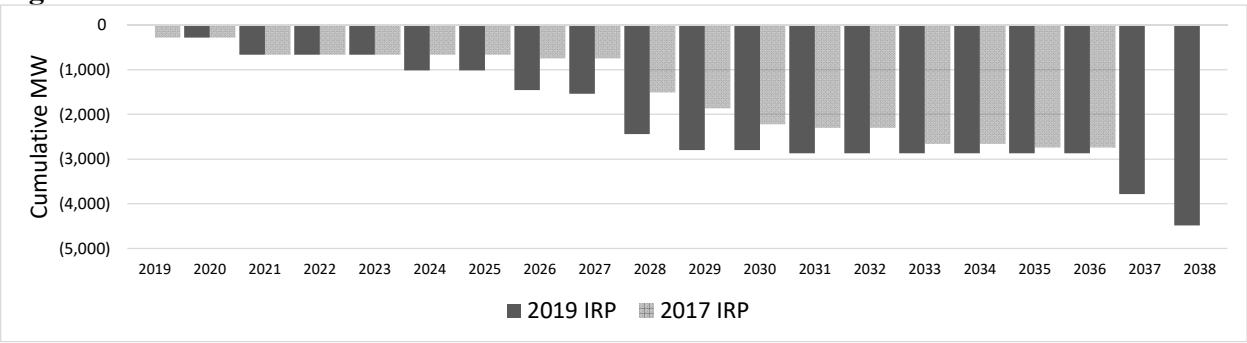
Coal resources have been an important resource in PacifiCorp's resource portfolio. Changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums) has allowed the company to buy increasingly low-cost, zero-emissions renewable energy from market participants, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as those 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 24 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 16 of the units by 2030 and 20 of the units by the end of the planning period in 2038. As shown in Figure 1.11, coal unit retirements in the 2019 IRP preferred portfolio will reduce coal-fueled generation capacity by over 1,000 MW by the end of 2023, nearly 1,500 MW by the end of 2025, nearly 2,800 MW by 2030, and nearly 4,500 MW by 2038.

Coal unit retirements scheduled under the preferred portfolio include:

- 2019 = Naughton Unit 3 (same as 2017 IRP), converted to natural gas in 2020
- 2020-2023 = Cholla Unit 4 (same as 2017 IRP)
- 2023 = Jim Bridger Unit 1 (instead of 2028 in the 2017 IRP)
- 2025 = Naughton Units 1-2 (instead of 2029 in the 2017 IRP)
- 2025 = Craig Unit 1 (same as 2017 IRP)
- 2026 = Craig Unit 2 (instead of 2034 in the 2017 IRP)
- 2027 = Dave Johnston Units 1-4 (same as 2017 IRP)
- 2027 = Colstrip Units 3-4 (instead of 2046 in the 2017 IRP)
- 2028 = Jim Bridger Unit 2 (instead of 2032 in the 2017 IRP)
- 2030 = Hayden Units 1-2 (same as 2017 IRP)
- 2036 = Huntington Units 1-2 (same as 2017 IRP)
- 2037 = Jim Bridger Units 3-4 (same as 2017 IRP)

Figure 1.11 – 2019 IRP Preferred Portfolio Coal Retirements*



* Note: Coal 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.

Carbon Dioxide Emissions

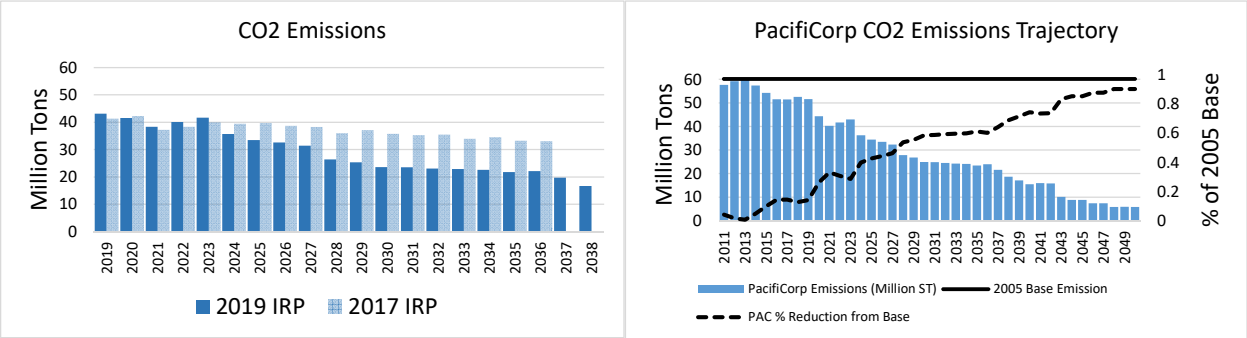
The 2019 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors, including PacifiCorp's participation in the Energy Imbalance Market (EIM), which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going expansion of renewable resources and transmission; and Regional Haze compliance that capitalizes on flexibility.

The chart on the left in Figure 1.12 compares projected annual CO_2 emissions between the 2019 IRP and 2017 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales, and in 2025, annual CO_2 emissions are down sixteen percent relative to the

2017 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2017 IRP preferred portfolio, and down 35 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.1 million tons in 2019 to 16.7 million tons in 2038—a 61.3 percent reduction.

The chart on the right in Figure 1.12 includes historical data, assigns emissions at a rate of 0.4708 tons/MWh to market purchases (with no credit to market sales), and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline (a ubiquitous baseline year in the industry), system CO_2 emissions are down 43 percent in 2025, 59 percent in 2030, 61 percent in 2035, 74 percent in 2040, 85 percent in 2045, and 90 percent in 2050.

Figure 1.12 – 2019 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Emissions Trajectory*



*Note: PacifiCorp CO_2 Emissions Trajectory reflects actual emissions through 2018 from owned facilities, specified sources and unspecified sources. From 2019 through the end of the twenty-year planning period in 2038, emissions reflect those from the 2019 IRP preferred portfolio with market purchases assigned the California Air Resources Board default emission factor (0.4708 tons/MWh) – emissions from sales are not removed. Beyond 2038, emissions reflect the rolling average emissions of each resource from the 2019 IRP preferred portfolio through the life of the resource.

Renewable Portfolio Standards

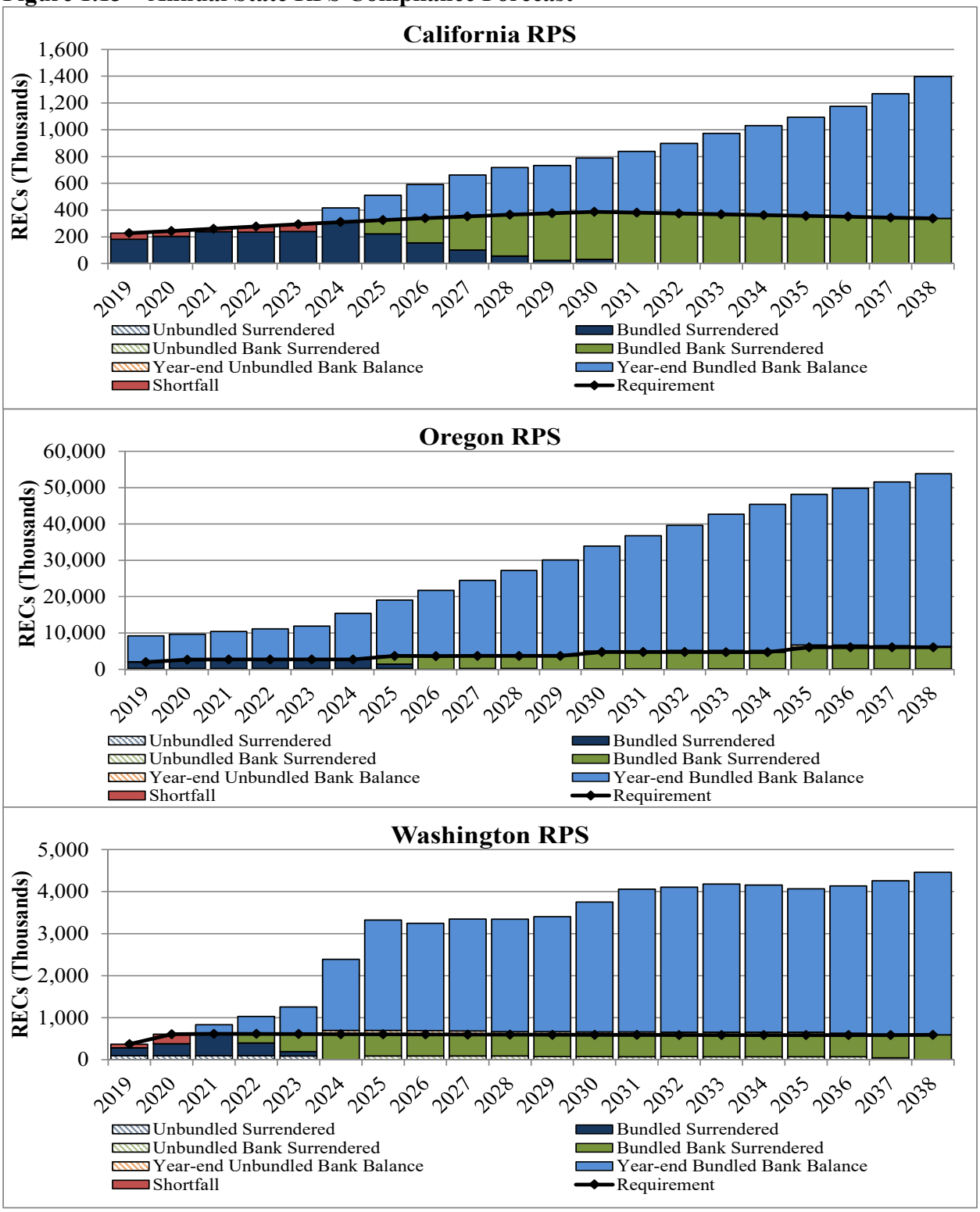
Figure 1.13 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are 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 2038 with the addition of new renewable resources and transmission in the 2019 IRP preferred portfolio. The California RPS compliance position is also improved by the addition of new renewable resources and transmission in the 2019 IRP preferred portfolio but requires a small amount of unbundled renewable energy credit (REC) purchases under 150 thousand RECs per year to achieve compliance through the near term. Washington RPS compliance is achieved with the benefit of repowered wind assets located in the west side, Marengo, Leaning Juniper and Goodnoe Hills, increased system renewable resources contributing to the west side beginning 2021[9], and unbundled REC purchases under 300 thousand

[9] PacifiCorp will propose the Multi-State Protocol allocation methodology in a December 13, 2019 Washington general rate case (GRC) filing. The methodology would allocate a system generation share of all non-emitting system resources to Washington. The 2019 IRP Annual State RPS Compliance Forecast reflected in Figure 1.13 reflects PacifiCorp's proposal to be filed in the rate case starting in 2021. Upon approval, the effective date of the new allocation methodology would be January 1, 2021.

RECs per year through 2021. Under current allocation mechanisms, Washington customers do not benefit from the new renewable resources added to the east side of PacifiCorp's system. 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 2019 IRP preferred portfolio.

Figure 1.13 – Annual State RPS Compliance Forecast



Load and Resource Balance

A key element of PacifiCorp's IRP process is to assess its load and resource balance over the 20-year planning horizon. The load and resource balance relies on the ability for specific types of resources to meet our forecasted coincident system peak load while accounting for reserve requirements, which ensures reliable electric service for PacifiCorp customers. In developing the resource plan, PacifiCorp applies a 13 percent planning reserve margin to account for near-term and longer-term planning uncertainties.

Capacity Balance

Table 1.3 shows PacifiCorp's summer capacity position from 2020 through 2029, with coal unit retirement assumptions and incremental energy efficiency savings from the 2019 IRP preferred portfolio before adding any incremental new generating resources. Before accounting for uncommitted market purchases that are assumed to be available when developing resource portfolios, PacifiCorp is capacity deficit over the summer peak through the planning horizon. When accounting for uncommitted market purchases, PacifiCorp is capacity deficient beginning 2028. With continued load growth and assumed coal unit retirements, the summer capacity position deteriorates over time.

Table 1.3 – PacifiCorp 10-Year Summer Capacity Position Forecast (MW)

System (Summer)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Existing Resource Capacity Contribution	10,437	10,671	10,638	10,641	10,347	10,290	9,953	9,899	8,999	8,494
Available FOT Capacity Contribution	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468
Total Existing Resource + FOTs	11,905	12,138	12,106	12,108	11,815	11,758	11,421	11,367	10,467	9,962
Obligation Net of Incremental DSM	9,876	9,882	9,918	9,953	9,982	10,005	9,962	9,966	9,985	9,998
13% Planning Reserve Margin	1,307	1,308	1,312	1,317	1,321	1,324	1,318	1,319	1,321	1,323
Obligation + 13% Planning Reserves	11,183	11,190	11,231	11,270	11,303	11,328	11,281	11,284	11,306	11,321
System Position without Uncommitted Market Purchases	(746)	(519)	(592)	(630)	(956)	(1,038)	(1,328)	(1,385)	(2,307)	(2,827)
Reserve Margin without Available FOTs	6%	8%	7%	7%	4%	3%	0%	-1%	-10%	-15%
System Position with Uncommitted Market Purchases Required to Meet Need	0	0	0	0	0	0	0	0	(839)	(1,359)
Reserve Margin with Available FOTs	13%	13%	13%	13%	13%	13%	13%	13%	5%	0%

Table 1.4 reflects a winter load and resource balance for the 2019 IRP and shows PacifiCorp's annual winter capacity position from 2020 through 2029, with coal unit retirement assumptions and incremental energy efficiency savings from the 2019 IRP preferred portfolio before adding any incremental new generating resources. Before accounting for uncommitted market purchases that are assumed to be available when developing resource portfolios, PacifiCorp is capacity deficient over the winter peak beginning 2024. When accounting for uncommitted market purchases, PacifiCorp is capacity deficient beginning 2029. As in the summer, with continued load growth and assumed coal unit retirements, the winter capacity position deteriorates over time.

Table 1.4 – PacifiCorp 10-Year Winter Capacity Position Forecast (MW)

System (Winter)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Existing Resource Capacity Contribution	11,627	10,770	10,746	10,671	9,560	9,558	9,212	9,124	8,382	7,949
Available FOT Capacity Contribution	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468
Total Existing Resource + FOTs	13,095	12,238	12,214	12,139	11,027	11,026	10,680	10,592	9,850	9,416
Obligation Net of Incremental DSM	8,671	8,695	8,725	8,743	8,734	8,751	8,631	8,634	8,645	8,666
13% Planning Reserve Margin	1,150	1,153	1,157	1,160	1,158	1,161	1,145	1,145	1,147	1,150
Obligation + 13% Planning Reserves	9,821	9,848	9,883	9,902	9,892	9,912	9,776	9,779	9,792	9,815
System Position without Uncommitted Market Purchases	1,806	922	864	769	(333)	(354)	(564)	(655)	(1,410)	(1,867)
Reserve Margin without Available FOTs	34%	24%	23%	22%	9%	9%	7%	6%	-3%	-8%
System Position with Uncommitted Market Purchases Required to Meet Need	1,806	922	864	769	0	0	0	0	0	(399)
Reserve Margin with Available FOTs	34%	24%	23%	22%	13%	13%	13%	13%	13%	9%

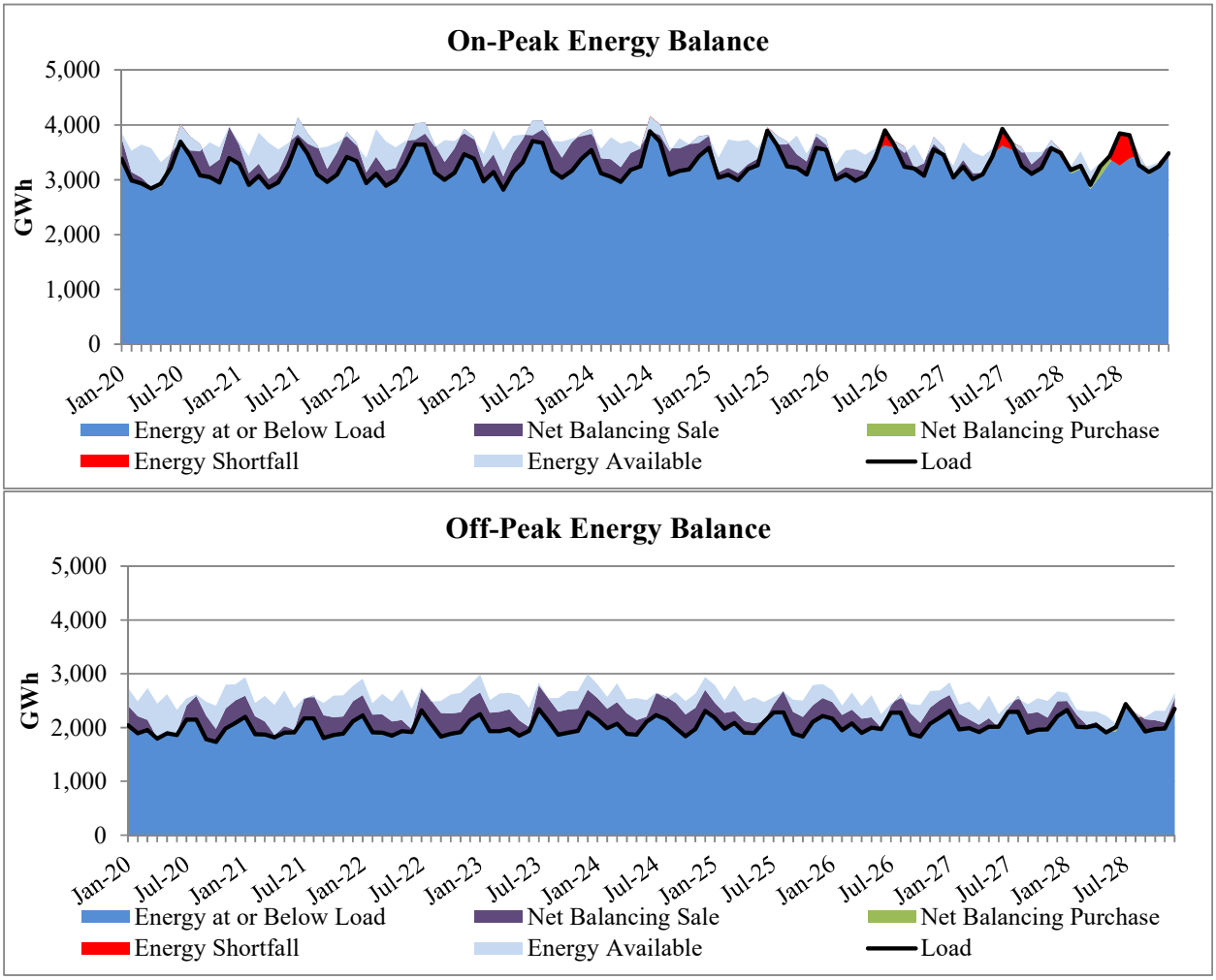
Energy Balance

The capacity position shows how existing resources and loads balance during the coincident peak summer and winter periods, accounting for assumed coal unit retirements and incremental energy efficiency savings from the 2019 IRP preferred portfolio. Outside of these peak periods, PacifiCorp economically dispatches its resources to meet changes in load while taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, PacifiCorp can dispatch resources that, in aggregate, exceed then-current PacifiCorp customer load obligations, facilitating off-system wholesale market power sales that reduce costs for PacifiCorp customers. Conversely, at times when system resource costs are greater than prevailing market prices, system balancing wholesale market power purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how PacifiCorp manages net power costs on behalf of its customers.

Figure 1.14 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given current planning assumptions and recent wholesale power and natural gas prices.[10] The figure shows expected monthly energy production from system resources during on-peak and off-peak periods in relation to load, reflecting coal unit retirement assumptions and incremental energy efficiency savings from the 2019 IRP preferred portfolio before adding any new generating resources. At times, system resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 1.14 also shows how much system energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and indicate short energy positions without addition of any new generating resources to the portfolio. During on-peak periods, the first notable energy shortfall appears in summer 2026. There are no energy shortfalls during off-peak periods over this timeframe.

[10] On-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday. Off-peak periods are all other hours.

Figure 1.14 – Economic System Dispatch of Existing Resources in Relation to Monthly Load



2019 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 2019 IRP include:

- Coal Studies
  PacifiCorp built upon prior IRP coal unit analysis with a robust and comprehensive analysis of its coal fleet. Results of this analysis, described in more detail in the 2019 IRP Volume II, Appendix R, Coal Studies, informed the portfolio-development phase of the 2019 IRP.

- Endogenous Modeling of Transmission Upgrades
  As part of it 2019 IRP, PacifiCorp was successfully able to provide its System Optimizer (SO) model with the ability to endogenously view costs and transmission capability associated with certain transmission upgrades that allowed for selection of specific transmission investments that coincide with new resource additions. This is an improvement from prior IRPs, where transmission upgrades and associated costs could only be coarsely evaluated in SO model

resource selections that required post-modeling assessment of upgrade costs after resource portfolios were developed. New transmission modeling capabilities include the endogenous 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. Limitations of this approach include transmission options that interact with multiple or complex elements of the IRP transmission topology. These transmission options were therefore studied as sensitivity cases in the 2019 IRP.

- Targeted Portfolio Reliability Analysis
  PacifiCorp developed in its 2019 IRP an approach for assessing the reliability of its portfolios and the ability of each unique resource portfolio to meet reliability requirements. With significant levels of economic renewable resource being selected in every resource portfolio, PacifiCorp found that subsequent modeling of these resource portfolios using the Planning and Risk model (PaR), 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 developed a process by producing hourly deterministic PaR runs for select years to identify the incremental need for reliability resources that could then be added to a resource portfolio to ensure there is sufficient flexible capacity to meet reliability requirements.

- Improved Storage Modeling
  As PacifiCorp observed an increased presence of battery storage resources in many resource portfolios, it developed a modeling tool to optimize charge and discharge cycles against a "net load" profile (load net of wind and solar generation) to better represent battery storage resources in a resource portfolio that has increasing levels of incremental renewable resources.

- Improvements in Modeling Assumptions
  In the 2019 IRP, PacifiCorp improved granularity of its analysis of reserve requirements from monthly to hourly. PacifiCorp also incorporated into its modeling capacity contribution values that decline with increasing penetration of wind and solar resources.

- Stakeholder Feedback Forms
  In its 2019 IRP, PacifiCorp expanded upon its stakeholder feedback form process by posting not only the forms received from stakeholders but also PacifiCorp's response throughout the public-input process. PacifiCorp received and responded to over 133 stakeholder feedback forms in the 2019 IRP up from 19 in the 2017 IRP.

- Stakeholder Requests
  PacifiCorp was able to accommodate numerous stakeholder requests to develop additional stakeholder-driven studies during the public-input process. PacifiCorp and stakeholders identified and requested alternative modeling scenarios, including proposed changes to methodology such as an alternate DSM-bundling methodology, which was informed by discussion during the public-input process. Further, and as informed by PacifiCorp's analysis during the coal studies, initial portfolios were developed with the ability for stakeholder input to request other variations of coal retirement cases. Results from some of these studies led PacifiCorp to consider additional scenarios.

- Public-Input Meetings
  PacifiCorp continued to coordinate with stakeholders to include video conference connections with locations in Cheyenne, Wyoming, and Denver, Colorado, to supplement the existing video conference connection between Portland, Oregon, and Salt Lake City, Utah, in addition to the phone conference capability. PacifiCorp responded to stakeholder requests to schedule shorter lunch breaks and start earlier on the second day of two-day public-input meetings.

Supplemental Studies

PacifiCorp's 2019 IRP relies on numerous supplemental studies that support the derivation of specific modeling assumptions critical to its long-term resource plan. A description of these studies, discussed in more detail in appendices filed with the 2019 IRP, is provided below.

- 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.

- Private Generation Resource Assessment
  This supplemental study, prepared by Navigant Consulting, Inc., was refreshed for the 2019 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 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.

- Western Resource Adequacy Evaluation
  PacifiCorp updated its analysis of regional resource adequacy to support its assumptions for wholesale power market purchase limits adopted for the 2019 IRP. The western resource adequacy evaluation presents data from the Western Electricity Coordinating Council's Power Supply Assessment, reviews recent resource adequacy studies performed for the Pacific Northwest region, and summarizes PacifiCorp's historical peak period market purchase data.

- Planning Reserve Margin Study
  The 2019 IRP was developed targeting a 13 percent planning reserve margin, which influences the need for new resources and is applied during the portfolio development process. In the 2019 IRP planning reserve margin study, PacifiCorp analyzes the relationship between cost and reliability among ten different planning reserve margin levels, accounting for variability and uncertainty in load and generation resources.

- Capacity Contribution Study
  PacifiCorp made significant enhancements to the capacity contribution values applied to certain resources for the 2019 IRP. At the start of the IRP process, PacifiCorp developed resource-specific capacity contribution values for wind, solar, storage, energy efficiency, and load control programs, starting with the capacity factor approximation method ("CF Method") used in previous IRPs. For wind and solar, capacity contribution values were modified to account for resource penetration levels based on equivalent conventional power studies. For storage and load control programs, the capacity factor approximation calculation was refined

to account for outage durations in each iteration, to better assess the capability of these energy-limited resources. These initial values were used in the portfolio development process. As capacity contribution is dependent on all components in a portfolio, PacifiCorp assessed the reliability of every portfolio. For the preferred portfolio, the effective capacity contribution for each resource was reassessed based on an updated CF Method to inform development of the load and resource balance.

- Flexible Reserve Study
  This study evaluates the need for flexible resources as a result of 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 in the PaR model. Reserve costs estimated in the study are also applied during the portfolio development process in the SO model.

- 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 2019 IRP, PacifiCorp updated its stochastic parameter input assumptions with more current historical data.

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

- Renewable Resources Assessment
  Commissioned by PacifiCorp for its 2019 IRP, Burns and McDonnell Engineering Company (BMcD) evaluated various renewable energy resources in support of the development of PacifiCorp's IRP. The Renewable Resources 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.

- 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 study provides details on these grid services and on how energy storage resources can be configured and sited to maximize the benefits they provide.

Action Plan

The 2019 IRP action plan identifies specific resource actions PacifiCorp will take over the next two to four years to deliver resources included in the preferred portfolio. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed during the development of the 2019 IRP, and other resource activities described in the 2019 IRP. Table 1.5Table 1.5 details specific 2019 IRP action items by category.

Table 1.5 – 2019 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Naughton Unit 3:** • PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory notices and filings, in 2020. Initiate procurement of materials in Q4 2019. Conversion completed in 2020.
1b	**Cholla Unit 4:** • PacifiCorp will initiate the process of retiring Cholla Unit 4, including all required regulatory notices and filings, as soon as practicable, but will remove Cholla Unit 4 from service no later than January 2023 and earlier if possible. • PacifiCorp will continue to coordinate with the plant operator to transition employees, develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans and confirm joint-ownership obligations; complete required regulatory notices and filings; administer termination, amendment, or close-out of existing permits, contracts and other agreements; and coordinate with state and local stakeholders as appropriate. • By the end of Q1 2020, the plant operator will be requested to develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans, and confirm joint-ownership obligations. • By the end of Q2 2020, the plant operator will be requested to file required transmission interconnection and transmission services unit retirement notices/request for study. • By the end of Q4 2020, PacifiCorp will finalize an employee transition agreement with the plant operator.
1c	**Jim Bridger Unit 1:** • PacifiCorp will initiate the process of retiring Jim Bridger Unit 1 by the end of December 2023, including completion of all required regulatory notices and filings. By the end of Q2 2020, file a request with PacifiCorp transmission to study the year-end 2023 retirement of Jim Bridger Unit 1. By the end of Q2 2021, confirm transmission system reliability assessment and year-end 2023 retirement economics in 2021 IRP filing. • By the end of Q2 2021, finalize an employee transition plan.

	• By the end of Q2 2021, develop a community action plan in coordination with community leaders. • By the end of Q4 2021, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Jim Bridger Unit 1. • By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
1d	**Naughton Units 1-2:** • 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 2022, file a request with PacifiCorp transmission to study the year-end 2025 retirement of Naughton Units 1 and 2. • By the end of Q2 2022, finalize an employee transition plan. • By the end of Q2 2022, develop a community action plan in coordination with community leaders. • By the end of Q2 2023, confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, 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. • By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
1e	**Craig Unit 1:** • The plant operator will be requested to administer termination, amendment, or close-out of existing permits, contracts, and other agreements to support retiring Craig Unit 1, including completion of all required regulatory notices and filings, by the end of December 2025.
Action Item	**2. New Resource Actions**
2a	**Customer Preference Request for Proposals:** • PacifiCorp will work with customers to achieve their respective resource preference requirements. By the end of Q4 2019, sign a fifteen year 80 MW Power Purchase Agreement (PPA) for Utah solar for six Utah Schedule 34 customers. By the end of Q4 2019, sign two 20-year PPAs of approximately 80 MW for a large Utah Schedule 34 customer. Monitor the finalization of rules by the Public Service Commission of Utah for HB 411 (anticipated by the end of Q1 2020), that provides a path forward for development of a program for participating communities to begin procuring renewable resources.

2b	**<u>All Source Request for Proposals:</u>** • PacifiCorp will issue an all-source request for proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2023. • By the end of Q4 2019, file a request for interconnection queue reform with the Federal Energy Regulatory Commission (FERC) and make state filings to initiate the process of identifying an independent evaluator. • In Q1 2020, file a draft all-source RFP with the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, as applicable. • In Q2 2020, receive approval from FERC to reform the interconnection queue. • In Q2 2020, receive approval of the all-source RFP from applicable state regulatory commissions and issue the RFP to the market. • In Q3 2020, identify a preliminary final shortlist from the all-source RFP and initiate transmission interconnection studies consistent with queue reform as approved by FERC. • In Q2 2021, 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 2022 execute definitive agreements with winning bids from the all-source RFP. • By Q4 2023, winning bids from the all-source RFP achieve commercial operation.
Action Item	**3. Transmission Action Items**
3a	**<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.
3b	**<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.

3c	**Northern Utah Reinforcements:** • Rebuild two miles of the Morton Court –Fifth West 138 kV line. • Loop existing Populus–Terminal 345 kV line into both Bridgerland 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 in support of 2019 IRP preferred portfolio for resource additions in the northern Utah.
3d	**Utah South Reinforcements:** • 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. • Yakima Washington Reinforcements: 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 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.
3e	**Yakima Washington Reinforcements:** • 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 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 Hemmingway (B2H):** • Continue to support the project under the conditions of the Boardman to Hemingway Transmission Project 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.

<table>
<tr><td>3g</td><td><u>Energy Gateway West:</u>
• 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 support the projects by providing information and participating in public outreach.</td></tr>
<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 Class 2 DSM (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 will be provided in Appendix D in Volume II of the 2019 IRP.
<table>
<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2019</td><td>562</td><td>126</td></tr>
<tr><td>2020</td><td>536</td><td>132</td></tr>
<tr><td>2021</td><td>538</td><td>133</td></tr>
<tr><td>2022</td><td>571</td><td>143</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.
• Energy Efficiency Bundling: PacifiCorp will continue to evaluate alternate bundling methodologies of Class 2 DSM in the 2019 IRP.
• Direct-Load Control: PacifiCorp will acquire cost-effective Class 1 DSM (i.e., demand response) in Utah targeting approximately 29 MW of incremental capacity from 2020 through 2023.</td></tr>
<tr><th>Action Item</th><th>5. Front Office Transactions</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></tr>
</table>

Action Item	6. Renewable Energy Credit Actions
6a	**Renewable Portfolio Standards:** • PacifiCorp will pursue unbundled RFPs to meet its state renewable portfolio standard (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 then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington RPS targets.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

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 in light of its obligations to its customers, regulators, and shareholders.

PacifiCorp's selection of the 2019 IRP preferred portfolio is supported by comprehensive data analysis and an extensive stakeholder input-process, described in the chapters that follow. PacifiCorp's preferred portfolio continues investments in new wind, transmission, and demand-side management (DSM), while adding significant solar and battery. By 2025, the preferred portfolio includes nearly 3,000 megawatt (MW) of new solar resources, more than 3,500 MW of new wind resources, nearly 600 MW of battery storage capacity (all of which is combined with new solar resources), 860 MW of incremental energy efficiency resources and new direct load control capacity.

Over the 20-year planning horizon, the preferred portfolio includes more than 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, more than 2,800 MW of battery storage by 2038 (nearly 1,400 MW of which are stand-alone storage resources starting in 2028), and more than 1,890 MW of incremental energy efficiency resources and new direct load control capacity.

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes the construction of a 400-mile transmission line known as Gateway South connecting southeastern Wyoming and northern Utah.

Other significant studies conducted to support analysis in the 2019 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 planning reserve margin study;
- A western region resource adequacy assessment;
- A capacity contribution study;
- A flexible reserve study developed in coordination with a technical review committee;
- Updated stochastic parameters; and
- An updated load and resource balance.

Finally, the 2019 IRP reflects continued alignment efforts with PacifiCorp's annual ten-year business planning process. The purpose of the alignment, initiated in 2008, is to:

- Provide corporate benefits in the form of consistent planning assumptions;

- Ensure that business planning is informed by the IRP portfolio analysis, and, likewise, that the IRP accounts for near-term resource affordability concerns as they relate to capital budgeting; and
- Improve the overall transparency of PacifiCorp's resource planning processes to public stakeholders.

This chapter outlines the components of the 2019 IRP, summarizes the role of the IRP, and provides an overview of the public process.

2019 Integrated Resource Plan Components

The basic components of PacifiCorp's 2019 IRP include:

- Set of IRP principles and objectives adopted for the IRP effort (this chapter).
- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3).
- Description of PacifiCorp's transmission planning efforts and activities (Chapter 4).
- Load and resource balance on a capacity and energy basis based on the preferred portfolio and determination of the load and energy positions for the front ten years of the twenty year planning horizon (Chapter 5).
- Profile of resource options considered for addressing future capacity and energy needs (Chapter 6).
- Description of the IRP modeling, including a description of the resource portfolio development process, cost and risk analysis, and preferred portfolio selection process (Chapter 7).
- Presentation of IRP modeling results, and selection of top-performing resource portfolios and PacifiCorp's preferred portfolio including sensitivities (Chapter 8).
- Presentation of PacifiCorp's 2019 IRP action plan linking the company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource procurement risks (Chapter 9).

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

- Load Forecast Details (Volume II, Appendix A),
- IRP Regulatory Compliance (Volume II, Appendix B),
- Public Input Process (Volume II, Appendix C),
- Demand Side Management Resources (Volume II, Appendix D),
- Smart Grid discussion (Volume II, Appendix E),
- Flexible Reserve Study (Volume II, Appendix F),
- Plant Water Consumption data (Volume II, Appendix G),
- Stochastic Parameters (Volume II, Appendix H),
- Planning Reserve Margin Study (Volume II, Appendix I),
- Western Resource Adequacy Evaluation (Volume II, Appendix J),
- Capacity Expansion Results Detail (Volume II, Appendix K),
- Stochastic Simulation Results (Volume II, Appendix L),
- Case Study Fact Sheets (Volume II, Appendix M),
- Capacity Contribution Study (Volume II, Appendix N),

- Private Generation Study (Volume II, Appendix O),
- Renewable Resources Assessment (Volume II, Appendix P),
- Energy Storage Potential Evaluation (Volume II, Appendix Q) , and
- Coal Studies (Volume II, Appendix R).

In an effort to improve transparency PacifiCorp is also providing data discs for the 2019 IRP. These discs support and provide additional details for the analysis described within the document. Discs containing confidential information are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings.

The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[1] The main role of the IRP is to serve as a roadmap for determining and implementing PacifiCorp's long-term resource strategy according to this IRP mandate. 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 (RFP) 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.

While PacifiCorp continues to plan on a system-wide basis, the company recognizes that new state resource acquisition mandates and policies add complexity to the planning process and present challenges to conducting resource planning on this basis.

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 18 public-input meetings, some of which spanning two days to facilitate information sharing, collaboration, and expectations for the 2019 IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Table 2.1 lists the public input meetings/conferences and highlights major agenda items covered. Volume II, Appendix C (Public Input Process) provides more details concerning the public-input process.

Table 2.1 – 2019 IRP Public Input Meetings

Meeting Type	Date	Main Agenda Items
State Meeting	6/11/2018	Oregon state stakeholder comments

[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.

Meeting Type	Date	Main Agenda Items
State Meeting	6/12/18	Washington state stakeholder comments
State Meeting	6/18/18	Idaho state stakeholder comments
State Meeting	6/19/18	Wyoming state stakeholder comments
State Meeting	6/20/18	Utah state stakeholder comments
State Meeting	8/9/18	Utah State Stakeholder Meeting on IRP Process
General Meeting (2-Day)	6/28/18	2019 IRP Kick-off Meeting, Model Overview, Unit-by-Unit Coal Study Results
	6/29/18	Demand-Side Management Workshop
General Meeting (2-Day)	7/26/18	Energy Storage Workshop, Renewable Resource Schedules and Load Forecast, Distribution System Planning, Supply-Side Resource Study
	7/27/18	Environmental Policy, Renewable Portfolio Standards, Modeling Assumptions and Study Updates
General Meeting (2-Day)	8/30/18	Private Generation Study, Conservation Potential Assessment and Energy Efficiency Credits, Portfolio Development Process and Initial Sensitivity Studies, Flexible Reserve Study
	8/31/18	Market Reliance Assessment, Planning Reserve Margin Study, Capacity Contribution Study
General Meeting (2-Day)	9/26/18	Draft Supply-Side Resource Table, Intra-Hour Flexible Resource Credit, Environmental Policy, Price-Policy Scenarios, Transmission Overview and Updates
	9/27/18	Flexible Reserve Study Cost Results, Planning Reserve Margin Study and Capacity Contribution Study Results, Portfolios Discussion/Coal Studies Next Steps, Demand-Side Management Credits and Conservation Potential Assessment
General Meeting (phone conference)	10/9/18	Supply-Side Resource Table, Intra-Hour Flexible Resource Credits, Updated CO_2 Assumptions
General Meeting	11/1/18	Supply-Side Resource Table, Modeling Improvements and Updates, Update on Coal Studies
General Meeting (2-Day)	12/3/18	Coal Studies Discussion
	12/4/18	Coal Studies Discussion
General Meeting	1/24/19	Capacity Contribution Values for Energy-Limited Resources, Coal Studies Discussion
General Meeting (phone conference)	2/21/19	General Updates, Summary of Oregon Energy Efficiency Analysis Results
General Meeting	3/21/19	Coal Studies Discussion
General Meeting	4/25/19	Coal Studies Discussion
General Meeting (2-Day)	5/20/19	Conservation Potential Assessment, DSM Bundling Methodology, Updated Portfolio Matrix and Analysis
	5/21/19	Portfolio Analysis Discussion
General Meeting (2-Day)	6/20/19	Modeling Updates, Portfolio Analysis Results
	6/21/19	Portfolio Analysis Results
DSM Workshop	7/12/19	Conservation Potential Assessment, Demand-Side Management Portfolio Methodology
General Meeting (phone conference)	7/18/19	General Updates
General Meeting	9/5/19	Portfolio Analysis Results
General Meeting (2-Day)	10/3/19	Preferred Portfolio and Action Plan, Portfolio Development and Selection
	10/4/19	Portfolio Development and Selection, Sensitivities

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 company maintains a public website: (www.pacificorp.com/energy/integrated-resource-plan.html), an e-mail "mailbox" (irp@pacificorp.com), and a dedicated IRP phone line (503-813-5245) to support communications and inquiries among participants. Additionally, a Stakeholder Feedback Form was used to provide opportunities for stakeholders to submit additional input and ask questions throughout the 2019 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

- In 2009 Appalachia (mostly Pennsylvania and West Virginia), produced almost no natural gas; by late 2013 it was producing almost 12 billion cubic feet per day (BCF/D) and by end-of-year 2018, Appalachia was producing over 28 BCF/D. In short, supply from Appalachia continues to grow as volumes and costs prove to be, respectively, higher and lower than anticipated. Today, Appalachia accounts for 34 percent of the nation's gas supply, and by 2040 is expected to account for 44 percent, spurred by increased drilling efficiencies and rising demand. Day-ahead 2018 Henry Hub prices averaged $3.15/Million British thermal units (MMBtu), down 64 percent from 2008 prices.
- Federal and state tax credits, declining capital costs, and improved technology performance have put wind and solar "in the money" in areas of high potential. As such, wind and solar will 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.
- In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA) that will require the state to power 100 percent of its electricity from carbon-free resources by 2045. Rulemaking by state agencies, including the Washington Utilities and Transportation Commission (WUTC) and the Washington Department of Commerce commenced in July 2019. PacifiCorp is participating in rulemaking proceedings and will perform an analysis of the portfolio effects of the new requirements under CETA in a Supplement to the 2019 Integrated Resource Plan (IRP) on or before December 31, 2019.
- On March 8, 2019, Wyoming Senate File (SF) 0159 was passed into law. SF 0159 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.
- PacifiCorp and the California Independent System Operator Corporation (CAISO) launched the voluntary energy imbalance market (EIM) November 1, 2014, the first western energy market outside of California. The EIM has produced significant monetary benefits ($736 million total footprint-wide benefits as of July 31, 2019). A significant contributor to EIM benefits are 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.
- Near-term procurement activities focused on three areas—the purchase and sale of renewable energy credits, the purchase of new or repowered wind energy, firm power for western balancing authority, and Oregon solar resources.

Introduction

Chapter 3 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 market include capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). As discussed elsewhere in this IRP, future natural gas prices, the role of gas-fired generation and the falling costs and increasing efficiencies of renewables are some of the critical factors affecting the selection of the portfolio that best achieves least-cost, least-risk planning objectives.

On the government policy and regulatory front, a significant issue facing PacifiCorp continues to be planning for an eventual, but highly uncertain, climate change regulatory regime. This chapter focuses on climate change regulatory initiatives. A high-level summary of PacifiCorp's greenhouse gas emissions mitigation strategy is included as well as a review of significant policy developments for currently regulated pollutants.

Other topics covered in this chapter include regulatory updates on the Environmental Protection Agency (EPA), regional and state climate change regulation, the status of renewable portfolio standards, and resource procurement activities.

Wholesale Electricity Markets

PacifiCorp's system does not operate in an isolated 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 assuring that resources with the lowest operating cost are serving demand in a 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 keep its supply portfolio in balance with customers' constantly varying needs. 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 unutilized 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 tends to come online and go offline abruptly in congruence with changing weather conditions. Federal and state (where applicable) tax credits, declining capital costs, and improved technology performance have put wind and solar "in the money" in areas of high potential. As such, wind and solar will 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.

With regard to transmission, there are long-haul renewable-driven transmission projects, in advanced development in the U.S. WECC. These 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 400-mile 1,500 megawatt (MW) Gateway South project, with an online date of 2024, to transport Wyoming wind to central Utah. Similarly, Gateway West, a jointly proposed 1,000-mile project by PacifiCorp and Idaho Power would transport Wyoming wind to western Idaho to be picked up for westward delivery with a 2024 online date. In the eastern interconnect, the Grain Belt Express, a 780 mile 4,000 MW direct-current line is in advanced development to go live in 2023 to transport Kansas wind to Missouri, Illinois, and Indiana. Moreover, the eastern seaboard is seeing a rising acceptance of off-shore wind. After years of resistance, local opposition has softened as technology improvements allow wind turbines to be located further from shore. To date, eastern states have sanctioned over 17,000 MWs of offshore wind power and the Bureau of Ocean Energy Management has seen record prices paid for leases in federal waters. Regardless, offshore wind remains expensive and requires government policy support and subsidization.

The intermittency of renewable generation has also given rise to a greater need for fast-responding storage – essential for grid stability and resiliency. Pumped storage has been the traditional storage option but expansion is extremely limited due to topography limitations, with the best resources already harnessed. Of remaining mechanical, thermal, and chemical storage options, Lithium-ion (Li-ion) batteries have shown the most promise in terms of cost and performance improvement. In 2013, the California Public Utility Commission (CPUC) required investor-owned utilities to procure 1,325 MW of storage by 2020; that requirement is now close to being met. Utility-scale four-hour battery storage modules have fallen in price to $1500/kilowatt (kW); costs are expected to continue to decline as electric vehicle manufacturing drives further innovation. To date, five states have implemented energy storage targets or mandates, with another two states seriously considering implementation.[1] In California, the world's largest Li-ion battery, 300 MW, is scheduled to go online at Pacific Gas & Electric (PG&E)'s Moss Landing Power Plant in 2021. Hybrid co-located solar photo voltaic (SPV) and battery systems are now in Hawaii, Arizona, Nevada, California, and Texas. In February 2019, Arizona Public Service announced it would pair existing solar with 200 MWs of battery storage while Nevada Energy has contracted for 100 MW of battery storage to be paired with solar. But, perhaps most importantly, 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[2]. 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. As part of its 2019 IRP, PacifiCorp is evaluating the cost effectiveness of several energy storage systems, including pumped storage, stand-alone li-on batteries, as well as co-located solar and co-located wind.[3]

[1] California, New Jersey, New York, Massachusetts, and Oregon have either mandated or set energy storage targets while Nevada and Arizona are seriously studying the implementation of targets.

[2] 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)

[3] Solar or wind resources coupled with battery storage.

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. The resulting EIM became operational November 1, 2014. By December 2015, Nevada Energy had joined as did Puget Sound Energy and Arizona Public Service in 2016. Portland General Electric joined in 2017, followed by Powerex and Idaho Power in 2018, and Balancing Authority of Northern California in 2019. Today, Salt River Project and Seattle City Light are slated to join in 2020; Los Angeles Water & Power, Northwestern Energy, and Public Service Company of New Mexico in 2021, followed by Avista and Tucson Electric Power in 2022. 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 with all markets, electricity markets are faced with a wide range of uncertainties. However, some uncertainties are easier to evaluate than others. Market participants are routinely studying demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. The North American Electric Reliability Corporation (NERC) publishes an annual assessment of regional power reliability and any number of data services are available that track the status of new resource additions[4]. In its latest assessment, published December 2018, the NERC indicates that WECC as a whole, has adequate resources through 2026. However, WECC's Northwest Power Pool (NWPP), Rockies, and southwest reserve sharing group (SRSG) sub-regions fall short starting 2027[5]. The NERC's probabilistic studies indicate that WECC's CA/MX sub region's resource adequacy is at risk during off peak hours, starting as early as 2020.

There are other uncertainties that are more difficult to analyze 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. Given the increased role of natural gas-fired generation, gas prices are a critical determinant of western electricity prices, and this trend is expected to continue over the term of this plan's decision horizon. Another critical uncertainty that weighs heavily on the 2019 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 CO_2 emission policies. However, PacifiCorp's OFPC does include enforceable state climate programs that have been signed into law[6].

Natural Gas Uncertainty

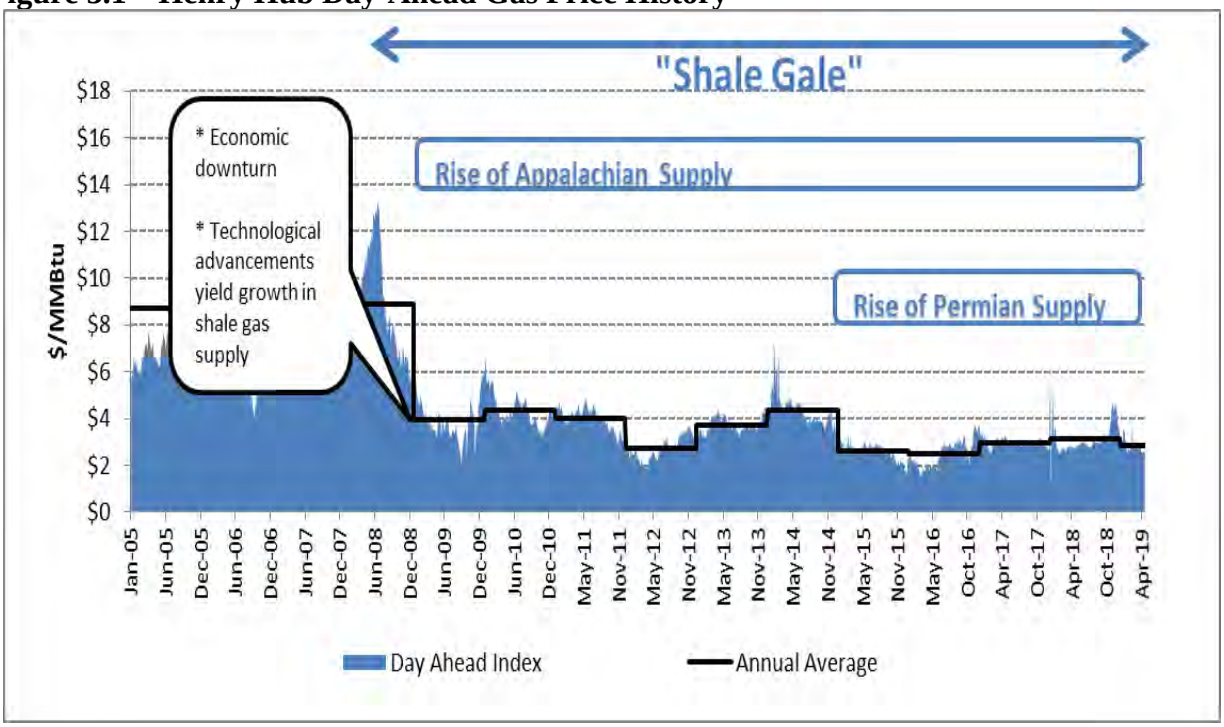
Since 2008, North American natural gas markets have undergone a remarkable paradigm shift. As shown in Figure 3.1, Henry Hub day-ahead gas prices hit a high of $13.31/MMBtu on July 2, 2008 and a low of $1.49/MMBtu on March 4, 2016. Day-ahead prices averaged $8.86/MMBtu in 2008, dropped to $3.94 in 2009, and have averaged $2.82 since 2015. Day-ahead 2018 Henry Hub prices

[4] 2018 Long-term Reliability Assessment, December 2018, North American Electric Reliability Assessment
[5] SRSG: Southwest Reserve Sharing Group; NWPP: Northwest Power Pool.
[6] A forecast of California carbon allowance prices is used as a proxy for future cap-and-trade allowance auction prices. Oregon's House Bill 2020, establishing a Climate Policy Office and directing it to adopt an Oregon Climate Action Program by rule is still in Committee and has not yet been signed into law.

averaged $3.15/MMBtu, down 64 percent from 2008 prices. The relative price placidity since 2009, labeled the "Shale Gale", reflects a story of supply – mostly that of Appalachian and, later, Permian supply[7].

In 2009 Appalachia (mostly Pennsylvania and West Virginia), produced almost no natural gas; by late 2013 it was producing almost 12 BCF/D and by end-of-year 2018, Appalachia was producing over 28 BCF/D. In short, supply from Appalachia continues to grow as volumes and costs prove to be, respectively, higher and lower than anticipated. Today, Appalachia accounts for 34 percent of the nation's gas supply, and by 2040 is expected to account for 44 percent, spurred by increased drilling efficiencies and rising demand.

Figure 3.1 – Henry Hub Day-Ahead Gas Price History



Source: Thomson Reuters as cited by the Energy Information Administration at: www.eia.gov/dnav/ng/hist/rngwhhdD.htm.

Historically, depletion of conventional mature resources largely offset unconventional resource growth, but as shale gas "came into its own," production gains outpaced depletion. Figure 3.2 through Figure 3.4 shows natural gas by source and location.

[7] Other significant shale gas plays include: Eagle Ford (TX); Haynesville (LA/TX); Niobrara (CO/WY); and the Bakken (ND/MT).

Figure 3.2 – U.S. Dry Natural Gas Production (Trillion Cubic Feet)

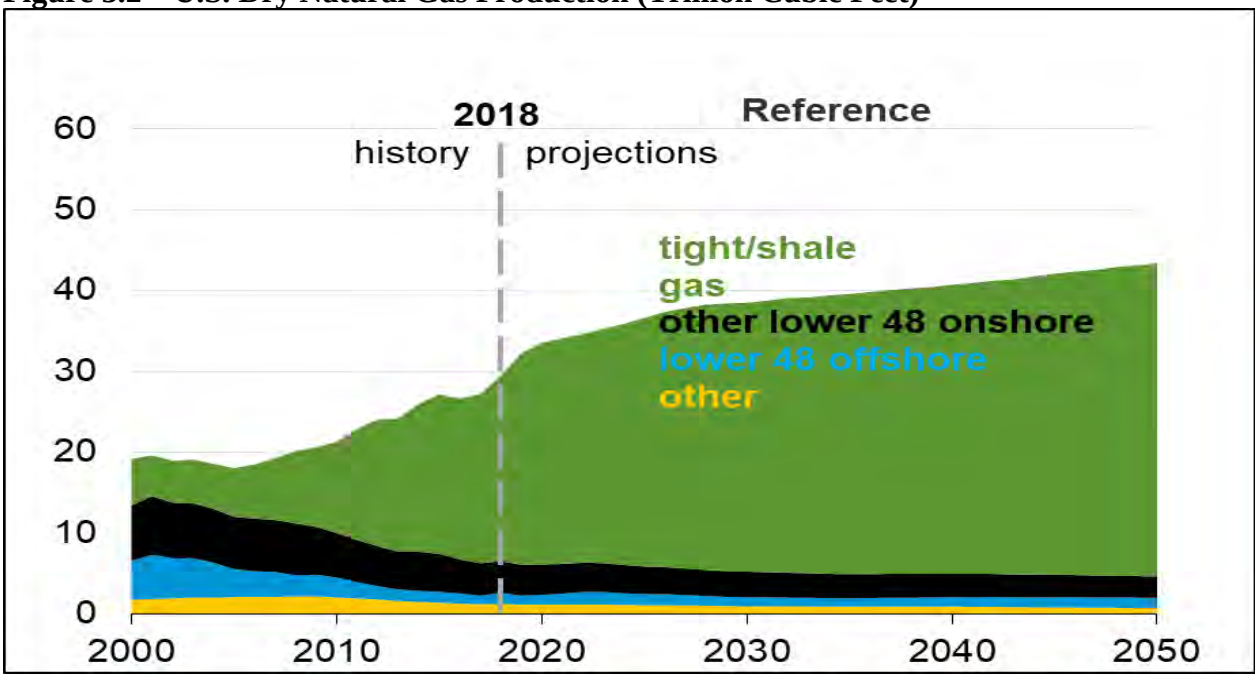
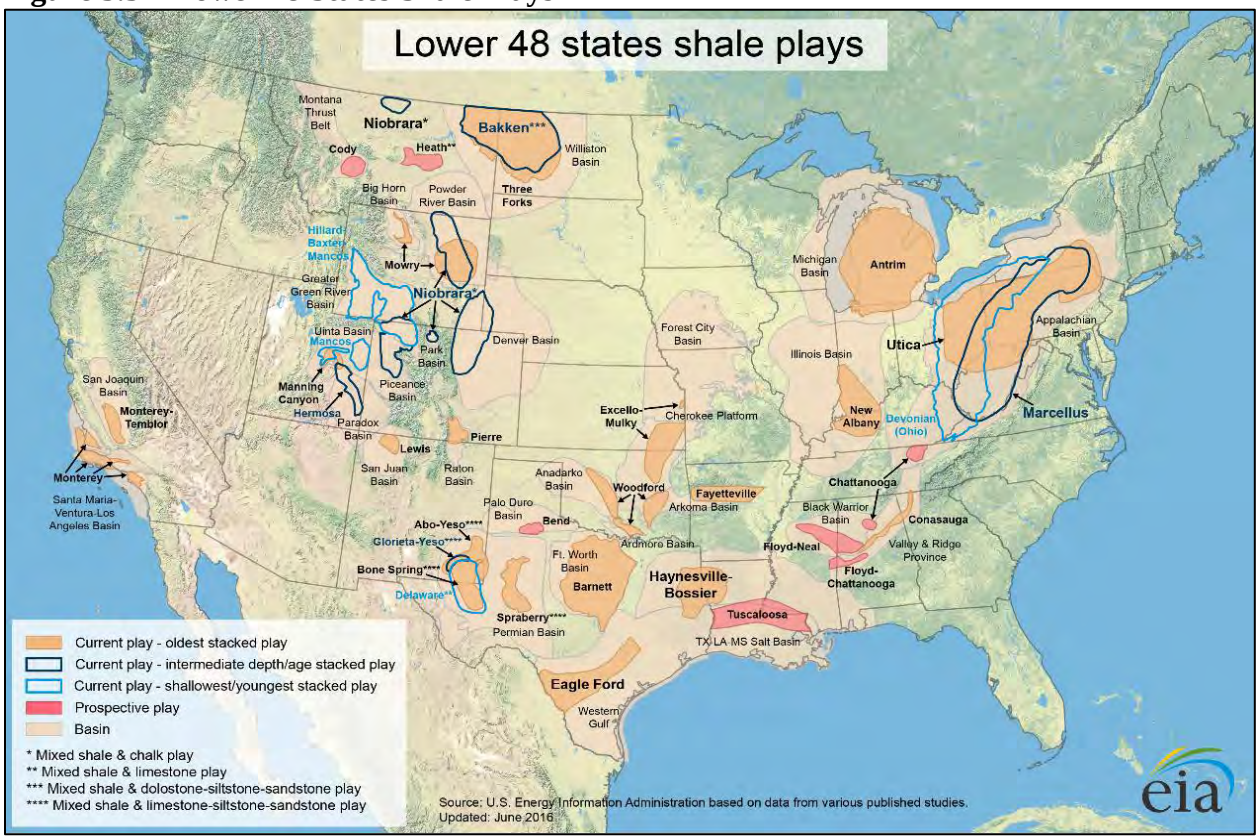
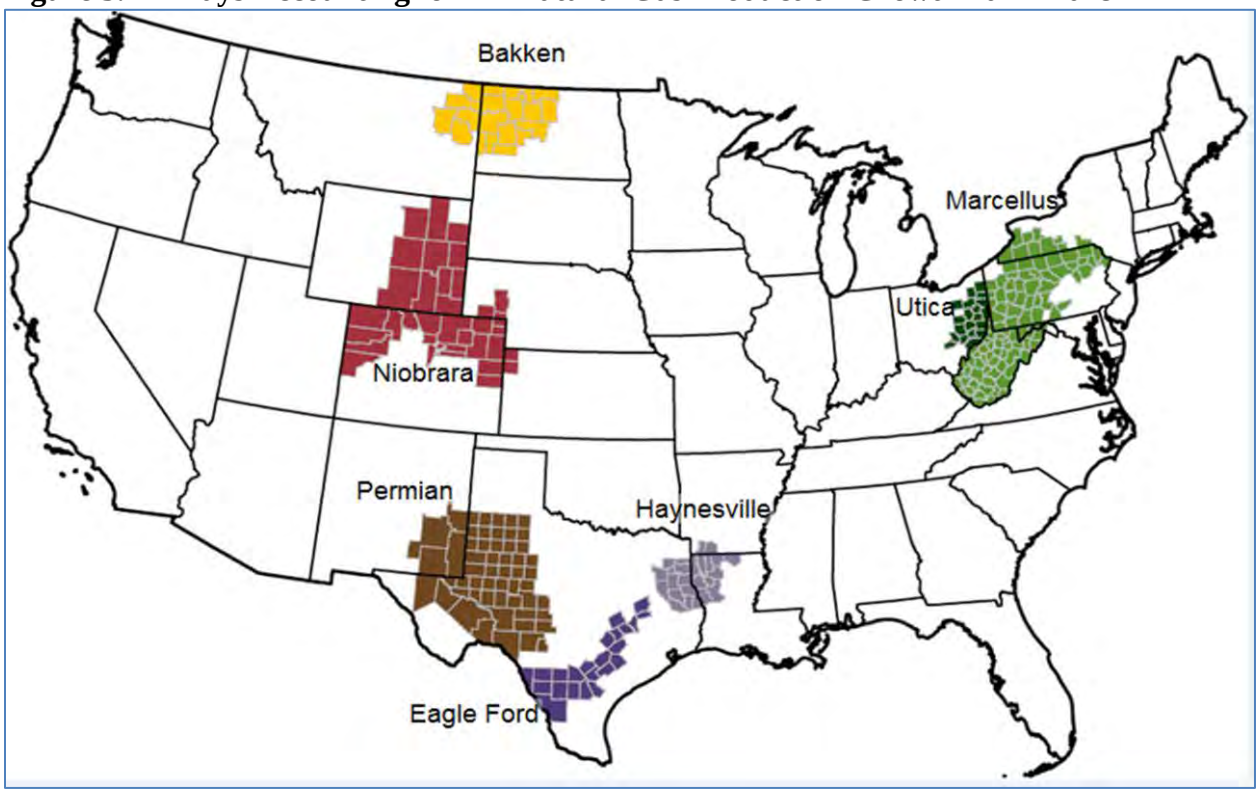


Figure 3.3 – Lower 48 States Shale Plays



Source: U.S. Department of Energy, Energy Information Administration

Figure 3.4 – Plays Accounting for All Natural Gas Production Growth 2011 -2018



Source: *Drilling Productivity Report*, May 13, 2019, U.S. Department of Energy, Energy Information Administration

Figure 3.5 shows Henry Hub NYMEX futures, as of May 28, 2019. While futures are rising it would appear that price expectations offer little "signal-to-drill" after all, annual futures don't even crack $4.00 per MMBtu. But as producers chase production efficiencies the "signal-to-drill" price becomes lower. Producers have discovered the economies of scale of deeper wells, super laterals, clustered well spacing, and repetitive fracking. The Utica's 'Purple Hayes" well, drilled in 2017, is over 27,000 feet deep with a lateral extension of 20, 803 feet.[8] As such, it has one of the longest onshore laterals ever drilled. The developer estimated that supersizing the well yielded an incremental internal rate of return of 130 percent and 215 percent, for condensate and natural gas, respectively.

But, for the next decade ultra-cheap natural gas will come from oil-targeted plays, especially in the Permian Basin. West Texas Intermediate two-year futures are currently hovering around $58/barrel -- more than enough to spur oil-targeted drilling in western Canada, the Permian, and Bakken. In the Bakken break even costs are below $50/barrel, while in the Permian, break-even costs range from $26/barrel to $50/barrel. Moreover, producers are "front-loading" oil production which releases a disproportionately large amount of associated gas. Front-loading involves drilling closely spaced "child" wells to quickly boost initial oil production but the resulting decrease in well pressure also releases inordinate quantities of associated gas.[9] This is especially true of Permian Basin oil wells, whose output naturally contains 20 to 50 percent natural gas. Currently, there is not enough Permian take-away capacity to accommodate this surge of natural gas. As such, there's been heavy flaring and pricing dislocation in the Permian as evidenced by Waha cash prices which averaged a negative $3.75/MMBtu on April 3, 2019. New take-away capacity coming

[8] *Super Laterals: Going Really, Really Long in Appalachia*, Larry Prado, Hart Energy.
[9] Note that while front-loading increases initial production it often shortens productive well life.

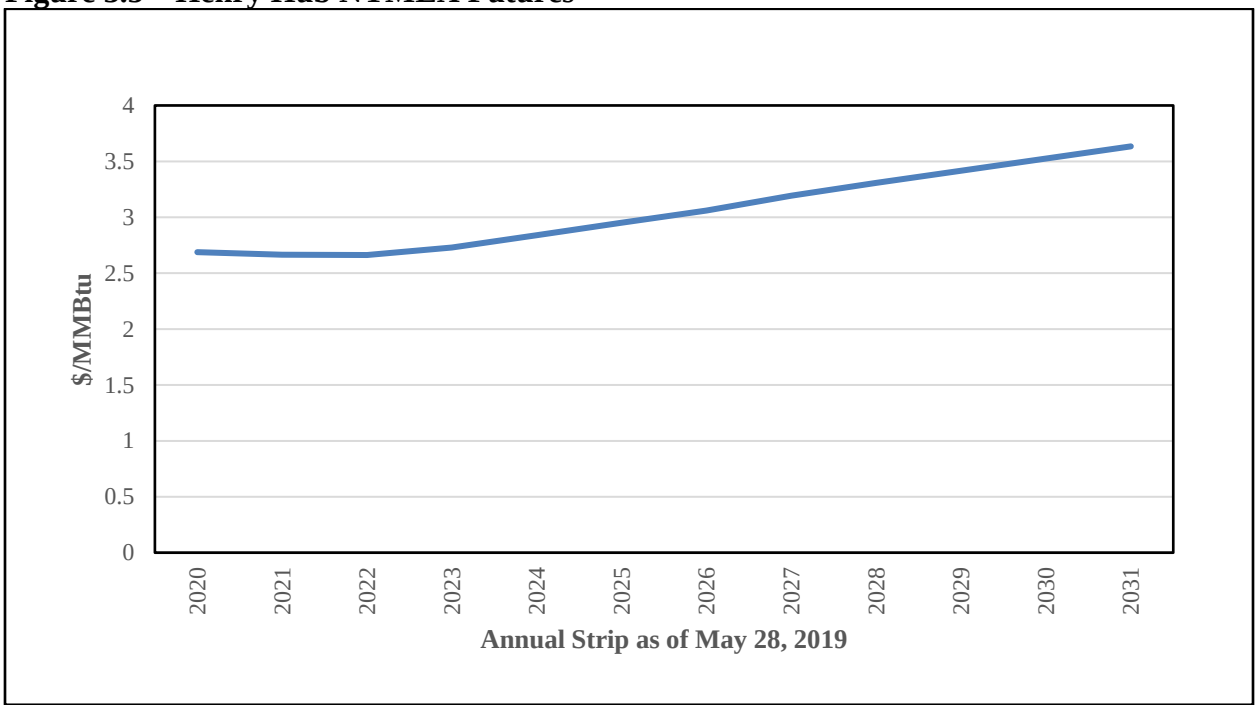
online in 2019 – 2020 will help alleviate the glut but natural gas prices are expected to remain depressed through 2020.

In 2016, following crude's price collapse, U.S. production finally fell to 8.8 million barrels of oil per day (MMbpd[10]) from a high of 9.6 MMbpd in 2015. In 2018, U.S. production averaged 10.9 MMbpd, hitting an all-time high of 11.97 MMBpd in December 2018. Moreover, the EIA estimated that as of April 2019, 8,390 wells remain drilled but uncompleted; these wells can be put into production quickly and represent a significant source of supply[11]. U.S. production can ramp up very quickly.

This resiliency of supply coupled with the flexibility to quickly ramp up production will shorten the length of asynchronous supply and demand cycles. Unexpected weather-induced demand spikes or supply disruptions will still whipsaw prices for short periods of time. But, Liquefied Natural Gas (LNG) startups, outages or dial backs could swing prices for longer periods given the magnitude of volumes coupled with locational concentration[12]. The global LNG market is expected to be in oversupply through 2022, especially during summer months. Summer feed gas normally bound for liquefaction would then be diverted onto the U.S. market, depressing prices. This summer dial back will act to also moderate winter prices by increasing storage and the likelihood of entering winter with an overhang. Although U.S. LNG tends to be the marginal global supplier, buyers are interested in U.S. LNG due to its low-cost natural gas supply and contract flexibility. Of note, even oil-rich Saudi Arabia has entered into a 20-year supply agreement for U.S. LNG. The imported LNG is expected to be used to replace Saudi Arabia's oil-fired power generation, thereby freeing up oil for export. To summarize, the key drivers of U.S. demand are: 1) LNG exports, 2) Mexican exports, and 3) power generation. Of the three, power generation is by far the largest but exports (especially LNG) are the fastest growing.

[10] MMbpd: Million barrels per day.
[11] EIA does not distinguish between oil and gas wells since over 50 percent of wells produce both.
[12] Current and expected facilities are mostly concentrated in the Gulf Coast.

Figure 3.5 – Henry Hub NYMEX Futures



Appalachian gas production will slow in the 2020s as associated gas, from oil-targeted plays, displaces it. However, Appalachian production and take-away capacity will pick up in the 2030's as associated gas volumes begin to dwindle. Rocky Mountain production gets squeezed by western Canadian, lower-48 associated gas, and Appalachian volumes. In the Northwest, where natural gas markets are influenced by production and imports from Canada, prices at Sumas have traded at a premium relative to AECO. This is likely to continue as AECO loses market share to Appalachia in serving AECO's Ontario and Midwest markets. In short, the challenge in gauging the uncertainty in natural gas markets will be one of timing. The North American natural gas supply curve continues to flatten as production efficiencies expose an ever-increasing resilient, flexible, and low-cost resource base. In such a world, managing long-term boom and bust cycles is not as crucial as managing shorter-term market perturbations.

The Future of Federal Environmental Regulation and Legislation

PacifiCorp faces continuously changing electricity plant emission regulations. Although the exact nature of these changes is uncertain, they are expected to impact the cost of future resource alternatives and the cost of existing resources in PacifiCorp's generation portfolio. PacifiCorp monitors these regulations to determine the potential impact on its generating assets. PacifiCorp also participates in rulemaking processes by filing comments on various proposals, participating in scheduled hearings, and providing assessments of proposals.

Federal Climate Change Legislation

To date, no federal legislative climate change proposal has been passed by the U.S. Congress. The election of Donald Trump as U.S. President reduces the likelihood of federal climate change legislation in the near term.

Federal Renewable Portfolio Standards

Since 2010, there has been no significant activity in the development of a federal renewable portfolio standard (RPS). Accordingly, PacifiCorp's 2019 IRP assumes no federal RPS requirement over the course of the planning horizon.

Federal Policy Update

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. New natural-gas-fueled power plants can emit no more than 1,000 pounds of CO_2 per megawatt-hour (MWh). New coal-fueled power plants can emit no more than 1,400 pounds of CO_2/MWh. The final rule largely exempts simple cycle combustion turbines from meeting the standards. On December 6, 2018, the EPA proposed to revise the NSPS for greenhouse gas emissions from new, modified, and reconstructed fossil fuel-fired power plants. EPA's proposal would replace EPA's 2015 determination that carbon capture and storage technology was the best system of emissions reduction for new coal units. The comment period for the proposed revisions closed in March 2019.

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

On August 3, 2015, the 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, the EPA proposed to repeal the Clean Power Plan and on August 21, 2018, proposed the Affordable Clean Energy (ACE) rule to replace the Clean Power Plan. 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 Clean Power Plan.

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 for that area. And that plan must be approved by EPA. The plan is developed so that once implemented, the NAAQS for the particular pollutant of concern will be achieved.

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 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), however Utah has until 2021 to develop ways to meet the standard.

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 measure technology 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 in 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 in certain national park and wilderness areas. On June 15, 2005, EPA issued final amendments to its regional haze rule. These amendments apply to the provisions of the regional haze rule that require emission controls known as the Best Available Retrofit Technology (BART) for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. These pollutants include fine PM, NO_X, SO_2, certain volatile organic compounds, 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. States are also required to periodically update or revise their implementation plans to reflect current visibility data and the effectiveness of the state's long-term strategy for achieving reasonable progress toward visibility goals. On December 14, 2016, EPA issued a final rule setting forth revised and clarifying requirements for periodic updates in state implementation plans. States are currently required to submit the next periodic update by July 31, 2021.

The regional haze rule is intended to achieve natural visibility conditions by 2064 in specific National Parks and Wilderness Areas, many of which are located in Utah and Wyoming where PacifiCorp operates generating units, as well as Arizona where PacifiCorp owns but does not operate a coal unit, and in Colorado and Montana where PacifiCorp has partial ownership in generating units operated by others, but are nonetheless subject to the regional haze rule.

On December 20, 2018, the EPA prepared a final guidance document to support states with the technical aspects of developing reginal haze state implementation plans for the second implementation period of the Reginal Haze Program.

Utah Regional Haze

In May 2011, the state of Utah issued a regional haze state implementation plan (SIP) requiring the installation of SO_2, NO_x 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 NO_X and PM portions. EPA's approval of the SO_2 SIP was appealed to federal circuit court. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the NO_X and PM SIP. PacifiCorp and the state's appeals were dismissed. In June 2015, the state of Utah submitted a revised SIP to EPA for approval with an updated BART analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, recognizing NO_X 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 the Utah's regional haze SIP and propose a federal implementation plan (FIP). The final rule requires the installation of selective catalytic reduction (SCR) controls at four of PacifiCorp's units in Utah: Hunter Units 1 and 2, and Huntington Units 1 and 2. On September 2, 2016, PacifiCorp filed petitions for administrative and judicial review of EPA's final rule and requested a stay of the effective date of the final rule. Unless the EPA's FIP is stayed or reversed, the controls are required to be installed by August 4, 2021.

On October 28, 2016, PacifiCorp filed a motion for stay with the 10th Circuit Court. EPA sent letters to Utah and PacifiCorp on July 14, 2017, indicating its intent to reconsider its FIP. EPA also filed a motion with the 10th Circuit Court of Appeals to hold the litigation in abeyance pending the rule's reconsideration. On September 11, 2017, the 10th Circuit Court granted the petition for stay and the request for abatement. The compliance deadline of the FIP and the litigation were stayed indefinitely pending EPA's reconsideration, and EPA was required to file status reports with the Court.

The EPA filed its first status report on December 13, 2017. The report stated that EPA was working with Utah to develop additional information in support of its reconsideration. The report stated that once the technical analyses (CAMx air quality modeling) had been fully developed, the EPA would proceed with rulemaking. Final CAMx modeling reports were delivered by PacifiCorp to Utah on September 21, 2018. On March 6, 2019, Utah Division of Air Quality staff presented a revised Utah Regional Haze SIP, based on the new modeling, to the Utah Air Quality Board. The Utah Air Quality Board voted in favor of sending the revised SIP out for public comment. On March 11, 2019 EPA filed its latest status report wherein EPA indicated that it was working with Utah to incorporate the results of the analysis. On April 1, 2019, the SIP revision was released for a 45-day public comment period, which closed on May 15, 2019.

On June 24, 2019, the Utah Air Quality Board unanimously voted to approve the Utah Regional Haze SIP Revision which incorporates and adopts the BART Alternative into Utah's Regional Haze SIP. The BART Alternative makes the shutdown of PacifiCorp's Carbon Plant enforceable under the SIP and removes the requirement to install SCR on Hunter Units 1 & 2, and Huntington Units 1 & 2. The state's final rule was published in the Utah Bulletin on July 15, 2019 and had an effective date of August 15, 2019. The Utah Division of Air Quality submitted the SIP Revision to the EPA for review on July 3, 2019. On September 9, 2019, the EPA provided a status report on Utah Regional Haze to the U.S. 10th Circuit Court of Appeals. The update stated that EPA is reviewing Utah's proposed SIP Revision, which was submitted by the state on July 3, 2019.

However, the EPA also stated that it was waiting on Utah to submit an additional minor revision to the SIP to address certain recordkeeping and reporting requirements. The additional modification relates to particulate matter (PM) emissions and exceedance reporting, which was a conditional requirement from EPA's 2016 partial approval of the SIP. The minor revision was proposed to the Utah Air Quality Board on September 4, 2019 and was issued for public comment on October 1, 2019. A draft of the revision was sent to EPA for concurrent review on October 2, 2019. The state anticipates getting final approval from the Utah Air Quality Board during its November board meeting and formally submitting the minor revision to EPA in December 2019.

The Western Regional Air Partnership (WRAP) is currently developing the modeling that the state will use for the implementation of the second planning period. Utah will use a 'Q/d' screening of 10 to determine which sources will be subject to the rule. The state is expecting to notify the effected sources soon and will require the sources to conduct a four-factor analysis. It is expected that the Hunter and Huntington facilities will be subject to the rule.

Wyoming Regional Haze

On January 10, 2014, EPA issued a final action in Wyoming requiring installation of the following NO_X and PM controls at PacifiCorp facilities:

- 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

Wyodak - Different aspects of EPA's final action were appealed by a number of entities. PacifiCorp appealed EPA's action requiring SCR at Wyodak. PacifiCorp successfully requested a stay of EPA's action as it pertains to Wyodak pending resolution of the appeals.

Naughton - In its 2014 rule, EPA indicated support for the conversion of the Naughton Unit 3 to natural gas 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 revision regarding Naughton Unit 3 to EPA on November 28, 2017. On March 7, 2017, Wyoming issued PacifiCorp a permit which allowed for adjusted emission limits upon Unit 3's conversion to natural gas; and allowed for 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 approving 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, On May 24, 2019, PacifiCorp provided Wyoming with a notice of commencement of construction for upgrades supporting Unit 3's conversion to natural gas, along with a notice of initial startup on natural gas firing in accordance with state permits and EPA's approval of the Wyoming SIP.

Jim Bridger - SCR was installed on Jim Bridger Units 3 and 4 by the dates required in the 2014 final rule. On February 5, 2019, PacifiCorp submitted to Wyoming an application and proposed SIP revision which would institute 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 application demonstrates that the proposed limits are more cost effective, results in less overall environmental impacts, and leads to better modeled visibility that SCR installation on Units 1 and 2. Wyoming is reviewing the application in coordination with EPA.

WRAP is currently developing the modeling that the state will use for the implementation of the second planning period. Wyoming has not determined which sources will be subject to the rule.

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 but 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 it relates to their interests. For the Cholla FIP requirements, the court stayed the appeals while parties attempt to agree on an alternative compliance approach.

In July 2016, the EPA issued a proposed rule to approve an alternative Arizona SIP, which includes converting Cholla 4 to a natural gas-fired unit or shutting the unit down in 2025. EPA approved the revised SIP on March 27, 2017.

WRAP is currently developing the modeling that the state will use for the implementation of the second planning period. Arizona will use a 'Q/d' screening of 20 to determine which sources will be subject to the rule. The state has notified the effected facilities has is requiring the facility to conduct a four-factor analysis by end of 2019.

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, the State of 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 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.

WRAP is currently developing the modeling that the state will use for the implementation of the second planning period. Colorado will use a 'Q/d' screening of 10 to determine which sources will be subject to the rule. The state is expecting to notify the effected facility soon and will require the facility to conduct a four-factor analysis by end of 2019.

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 the Supreme Court decision. 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. The comment period on the proposed rule closed on April 17, 2019. PacifiCorp is awaiting EPA's final action.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs), including coal ash, are the byproducts from the combustion of coal in power plants. CCRs have historically been considered exempt wastes under an amendment to the Resource Conservation and Recovery Act (RCRA); however, EPA issued a final rule in December 2014 to regulate CCRs for the first time. Under the final rule, EPA will regulate CCRs as non-hazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of CCRs. The final CCR Rule became effective October 19, 2015. Under the final rule, surface impoundments utilized for CCRs may need to close unless they can meet more stringent regulatory requirements. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCRs. Before the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCRs and hence are not subject to the final rule.

The final CCR regulation was set up to be enforced by citizen suits; however, in September 2016, the Senate passed, and in December 2016 President Obama signed, the Coal Combustion Residuals Regulatory Improvement Act, which sets forth the process and standards for EPA approval (and withdrawal) of a state's permitting program for coal combustion residual units. A state may incorporate either the requirements of the EPA rule into its permit program or other state requirements that, based on site-specific conditions, are at least as protective as the EPA rule.

The legislation:

- Authorizes the EPA to operate permit programs in states that have not been authorized.
- Clarifies that a coal ash residual unit is subject to the EPA rule until a permit is issued by either a state or EPA.
- Provides the EPA with inspection and enforcement authorities. Before EPA can take enforcement action in an authorized state, EPA must consider any other actions against the facility and determine if an enforcement action by EPA "is likely to be necessary" to ensure the facility is operating in accordance with its permit requirements.
- Authorizes EPA to operate a permit program in Indian country.
- Provides a permit shield for facilities that are operating in accordance with a state- or EPA-issued permit.

- Preserves other legal authorities or regulatory determinations in effect before enactment.

CCR Litigation

On August 21, 2018 the U.S. Court of Appeals for the District of Columbia issued a decision in the *Utility Solid Waste Activities Group, et al., vs. Environmental Protection Agency* case over the 2015 CCR Rule. Specifically, the Court vacated and remanded 40 CFR § 257.101(a) to EPA for additional consideration "consistent" with the Court's opinion. The 101(a) provision relates to the timing of closure for unlined CCR impoundments. PacifiCorp is awaiting EPA's final action.

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 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 waters of the U.S. 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 permit application requirements. The Dave Johnston permit application requirements 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 the Water Quality Division may require the facility to conduct an impingement characterization study. If an impingement characterization study is required, the final disposition of the Dave Johnston cooling water intake structure will not occur until the Water Quality Division has reviewed the study results.

Effluent Limit Guidelines

EPA first issued effluent guidelines for the Steam Electric Power Generating Point Source Category (i.e., the Steam Electric effluent guidelines or "ELG") in 1974, with subsequent revisions in 1977 and 1982. On November 3, 2015, the agency issued a final rule entitled *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*. The revised rule addressed the following wastestreams produced by steam-generation power plants: (1) flue gas desulfurization ("FGD") wastewater; (2) fly ash transport wastewater; (3) bottom ash transport wastewater; (4) flue gas mercury control ("FGMC") wastewater ("Hg control waste"); (5) combustion residual leachate (or "Leachate"); and (6) gasification wastewater.

Compliance with the revised ELG is required by dates determined by the permitting authority, which must be as soon as possible beginning November 1, 2018, but no later than December 31, 2023 (compliance deadlines are generally expected to be set at NPDES permit renewal dates).

On September 18, 2017, EPA announced that it intends to conduct a rulemaking to revise the definitions of Best Available Technology Economically Available ("BAT") effluent limitations, and Pretreatment Standards for Existing Sources ("PSES") for existing sources for bottom ash transport water and flue gas desulfurization wastewater. EPA is postponing the earliest compliance dates for the new, more stringent, BAT effluent limitations and PSES for both waste streams for a period of two years to November 1, 2020. BAT effluent limitations and pretreatment standards for all other wastestreams, or any of the other requirements in the 2015 Rule will not be revised during this reconsideration. EPA's action to postpone compliance dates in the 2015 Rule is intended to preserve the status quo for FGD wastewater and bottom ash transport water until EPA completes its next rulemaking.

On April 12, 2019, the Fifth Circuit Court of Appeals vacated the portions of the rule that set BAT for combustion residual leachate and legacy wastewater, and remanded those sections to the EPA for reconsideration. PacifiCorp is awaiting EPA's final action.

2015 Tax Extender Legislation

On December 18, 2015, President Obama signed tax extender legislation (H.R. 2029) that retroactively and prospectively extended certain expired and expiring federal income tax deductions and credits.

Bonus Depreciation

Fifty percent bonus depreciation was extended for property acquired and placed in service during 2015, 2016, and 2017. For property acquired and placed in service during 2018, 40 percent of the eligible cost of the property qualifies for bonus depreciation. For property acquired and placed in service during 2019, 30 percent of the eligible cost of the property qualifies for bonus depreciation. For property placed in service after December 31, 2019, there will be no bonus depreciation.[13]

Production Tax Credit (Wind)

[13] There is an exception for long-production-period property (generally property with a construction period longer than one year and a cost exceeding $1 million). Costs incurred on long-production-period property may qualify for bonus depreciation if physical construction has begun before the placed-in-service date of the bonus phase-out.

The production tax credit (PTC), currently 2.3 cents per kilowatt-hour (inflation adjusted), has been extended and phased out for wind property for which construction begins before January 1, 2020, as follows:

- 2015 – 100% retroactive
- 2016 – 100% (construction begins before January 1, 2017)
- 2017 – 80% (construction begins before January 1, 2018)
- 2018 – 60% (construction begins before January 1, 2019)
- 2019 – 40% (construction begins before January 1, 2020)

Production Tax Credit (Geothermal and Hydro)
The PTC for geothermal and hydro were granted a two-year extension as follows (no phase-out period was adopted):

- 2015 – 100% retroactive
- 2016 – 100% (construction begins before January 1, 2017)

30% Energy Investment Tax Credit (Wind)
The investment tax credit (ITC) has been extended and phased out for wind property for which construction begins before January 1, 2020, as follows:

- 2015 – 30% retroactive
- 2016 – 30% (construction begins before January 1, 2017)
- 2017 – 24% (construction begins before January 1, 2018)
- 2018 – 18% (construction begins before January 1, 2019)
- 2019 – 12% (construction begins before January 1, 2020)

30% Energy Investment Tax Credit (Solar)
The ITC has been extended and steps down for solar property for which construction begins before January 1, 2022, as follows:

- 2015 – 30% retroactive
- 2016 – 30% (construction begins before January 1, 2017)
- 2017 – 30% (construction begins before January 1, 2018)
- 2018 – 30% (construction begins before January 1, 2019)
- 2019 – 30% (construction begins before January 1, 2020)
- 2020 – 26% (construction begins before January 1, 2021)
- 2021 – 22% (construction begins before January 1, 2022)
- 2022 – 10% (construction begins on or after January 1, 2022)

State Policy Update

California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. The first auction of greenhouse gas allowances was held in California in November 2012, and the

second auction in February 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances and purchase the required amount of allowances necessary to meet its compliance obligations.

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 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 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. Most recently, 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.

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 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.

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 conversation 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. Rulemaking by state agencies, including the WUTC and the Washington Department of Commerce commenced in July 2019. PacifiCorp is participating in rulemaking proceedings and will perform an analysis of the portfolio effects of the new requirements under CETA in a Supplement to the 2019 IRP on or before March 31, 2019.

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 implementation and approval of the other programs was completed by January 1, 2017.

Wyoming

On March 8, 2019, Wyoming Senate File 0159 was passed into law. SF 0159 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 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 0159 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 one hundred percent cost recovery in rates for the cost of the power purchase agreement and the agreement is one hundred percent allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have all adopted 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 3.1, with additional discussion below.

Table 3.1 – 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) • SB 5116 (2019)	• 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 carbon-free 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 • 100% carbon neutral by 2030 • planning target of 100% renewable and non-emitting by 2045 * 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[14] 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.[15] 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.[16] SB 350 established a greenhouse gas reduction target of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 and expanded the state's renewables portfolio standard to 50 percent by 2030. In September 2018, the signing of SB 100, the Clean Energy Act of 2018, further expanded and accelerated the California RPS to 60 percent by 2030 and directed the state's agencies to plan for a longer-term goal of 100 percent of total retail sales of electricity in California to come from eligible renewable and zero-carbon resources by December 31, 2045.

SB 2 (1X) created multi-year RPS compliance periods, which were expanded by SB 100. The California Public Utilities Commission approved compliance periods and corresponding RPS procurement requirements, which are shown in Table 3.2.

Table 3.2 – 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)

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

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)	(35.8% * 2021 Retail Sales) + (38.5% * 2022 Retail Sales) + (41.3% * 2023 Retail Sales) + (44% * 2024 Retail Sales)
Compliance Period 5 (2025-2027)	(47% * 2025 Retail Sales) + (50% * 2026 Retail Sales) + (52% * 2027 Retail Sales)
Compliance Period 6 (2028-2030)	(54.7% * 2028 Retail Sales) + (57.3% * 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;[17] 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.[18]

Additionally, the California Public Utilities Commission 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 3.3.

[17] The use of another source to provide real-time ancillary services required to maintain an hourly or sub-hourly import schedule into a California balancing authority is permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource will count toward this portfolio content category.

[18] 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.

Table 3.3 – 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 California Public Utilities Commission (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.[19] 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,[20] 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:

- Development of a community solar program with at least 10 percent of the program capacity reserved for low-income customers.

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

- 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, in order to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[21]

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.

[21] 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.[22]

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.[23] 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 as a result 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. Following PacifiCorp's December 31, 2009 progress report, the Utah Division of Public Utilities' report to the Legislature stated: "Given PacifiCorp's projections of its loads and qualifying electricity for 2025, PacifiCorp is well positioned to meet a target of 20 percent renewable energy by 2025."

PacifiCorp filed its most recent progress report on December 31, 2014. This report showed that the company is positioned to meet its 20 percent target requirement of approximately 5.2 million megawatt-hours of renewable energy in 2025 from existing company-owned and contracted renewable energy sources.

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

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

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[24] 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 both to meet the RPS requirement.

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the WUTC demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[25]

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.

Under SB 5116, passed in 2019, Washington utilities are required to be carbon neutral by January 1, 2030 and institute a planning target of one hundred 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.

Transportation Electrification

The electric transportation market is in an emerging state,[26] and plug-in electric vehicles 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

[24] www.secstate.wa.gov/elections/initiatives/text/I937.pdf
[25] www.pacificpower.net/report
[26] As of June 2019, the market share of plug-in electric vehicles was two percent: www.nada.org/WorkArea/DownloadAsset.aspx?id=21474858563

PacifiCorp customers. In addition, increased adoption of electric transportation has the ability to improve air quality, 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.

To help manage and understand the potential future load growth impacts of electric transportation PacifiCorp is investing $26 million 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. Our investments include a $4 million partnership award from the U.S. Department of Energy to research and develop electric transportation and $3 million as part of the Oregon Clean Fuels Program.

Given the emerging state of electric transportation a forecast explicitly identifying the load associated with electric transportation on PacifiCorp's system is currently unavailable. Electric vehicle load is, however, 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.

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. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation and 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.

With the exception of the Klamath River and Weber hydroelectric projects, all of PacifiCorp's applicable generating facilities now operate under contemporary licenses from the FERC. In 2019, PacifiCorp initiated the FERC relicensing process for the Cutler Hydroelectric Project. This 30 MW project is located in Utah and has a 30-year license period that ends March 2024. Under a 2010 settlement agreement, amended in 2016, the 169 MW Klamath Hydroelectric Project is anticipated to operate under its existing license until project operations cease in 2021 with the

decommissioning of the project. The assumed date of Klamath project removal in the IRP is January 1, 2021. The 3.85 MW Weber project is currently in the FERC relicensing process.

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, 2016, PacifiCorp had incurred approximately $16 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 Weber, Cutler 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. The majority of these relicensing and settlement costs relate to PacifiCorp's three largest hydroelectric projects: Lewis River, Klamath River, and North Umpqua.

Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Chapter 5.

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 improvement 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.

Utah Rate Design Information

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. 13-035-184. 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. 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. This gives customers a price signal to encourage reduced consumption. 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. Currently, less than one percent of customers have opted to participate in the time-of-day rate option.

Changes in residential rate design that might facilitate IRP objectives include a critical peak pricing program or an expansion of time-of-use rates. These types of rate designs are discussed in more detail in Volume I, Chapter 6 (Resource Options). 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.

With the growth in the number of customers adopting private distributed generation, rates have begun to evolve to address the change in usage requirements and ensure appropriate cost recovery from these customers. A deeper consideration of the implications of current rates and rate designs is necessary to address growing issues with private generation and ensure the appropriate price signals are set for the changing circumstances. As a result of a settlement in Docket No. 14-035-114, new customer generators in Utah receive export credits that are valued at a different rate than retail rates as part of a transition program.

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 two optional time-of-day rates—one that differentiates energy rates for on- and off-peak usage, and one that differentiates power charges by on- and off-peak usage. Currently, about 19 percent of the eligible customers are on the energy time-of-day option and less than one percent are on the power time-of-day option.

Irrigation Rate Design

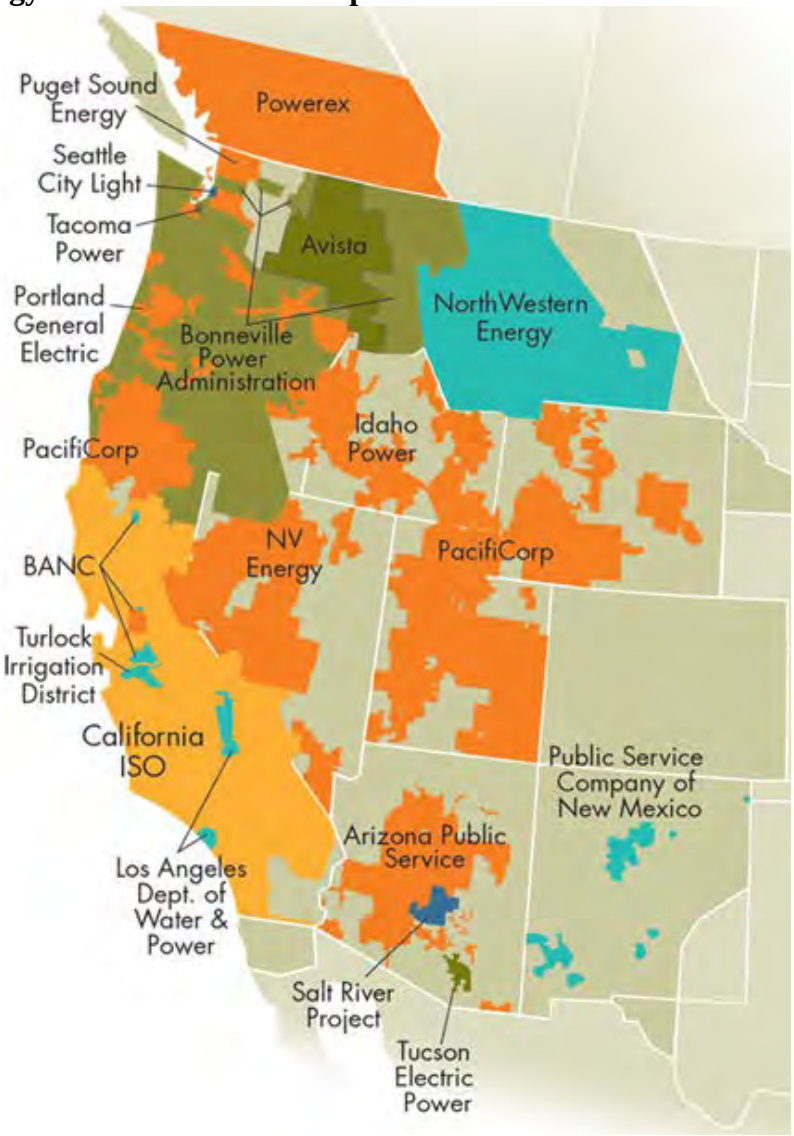
Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, a seasonal power charge, and energy charges. The annual and monthly customer charges provide some recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs 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.

Energy Imbalance Market

PacifiCorp and the CAISO launched the EIM November 1, 2014. The EIM is a voluntary market and the first western energy market outside of California. The EIM covers eight states in the United States of America and one province in Canada—British Columbia, California, Nevada, Arizona,

Idaho, Oregon, Utah, Washington, and Wyoming—and uses CAISO advanced market systems to dispatch the least-cost resources every five minutes. Since the launch of the EIM, NV Energy joined the market December 1, 2015; Puget Sound Energy and Arizona Public Service joined October 1, 2016; Portland General Electric joined October 1, 2017; Idaho Power and Powerex joined April 4, 2018; Balancing Authority of Northern California/Sacramento Municipal Utility District Phase 1 joined April 3, 2018. Entities scheduled to join the EIM include Salt River Project and Seattle City Light in April 2020; and Los Angeles Department of Power and Water, NorthWestern Energy, Turlock Irrigation District, BANC Phase 2 and Public Service Company of New Mexico in 2021; and Tucson Electric Power, Avista, Tacoma Power and Bonneville Power Administration in 2022. PacifiCorp continues to work with the CAISO, existing and prospective EIM entities, and stakeholders to enhance market functionality and support market growth.

Figure 3.6 – Energy Imbalance Market Expansion



The EIM has produced significant monetary benefits ($736 million total footprint-wide benefits as of July 31, 2019), 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 EIM 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 are 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 EIM in the west, a natural next question is – are there continued opportunities to increase economic efficiency and renewable integration beyond the scope of EIM but short of a fully regional independent system operator? PacifiCorp believes the answer may be yes, but several items that are critical to its success will need creative solutions; resource sufficiency, transmission utilization, voluntary nature and governance. Currently, the benefits of an extended day-ahead market (EDAM) in the west have not been assessed and the market design has not yet been developed. The concept of extending day-ahead market services are included in the CAISO's 2019 Draft Policy Initiatives Roadmap, which has an EDAM stakeholder initiative which entered the first stage of policy development October 10, 2019, with the issuance of an Issue Paper by the CAISO. The EDAM stakeholder initiative will tackle questions such as transmission utilization, grid management charges, governance and regulatory considerations in an open forum to reach consensus on a viable EDAM concept.

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 3.4 summarizes recent RFP activities.

Table 3.4 – PacifiCorp's Request for Proposal Activities

RFP	RFP Objective	Status	Issued	Completed
2017 Renewable Energy Credits RFP	Purchase renewable energy credits for Oregon Schedule 272 participation	Closed	August 2017	September 2017
2017 Renewable RFP	Purchase new or repowered wind renewable energy	Closed	September 2017	November 2018
2017 Solar RFP	Purchase solar renewable energy	Closed	November 2017	March 2018
2017 Market Resource RFP	Purchase firm power for PacifiCorp's western balancing authority	Closed	November 2017	November 2017
2018 Oregon Community Solar RFP	Purchase solar energy or Oregon Community Solar	Ongoing	July 2018	On hold pending final program rules
2018 Renewable Energy Credits RFP	Purchase renewable energy credits for Oregon Schedule 272 participation	Closed	August 2018	September 2018

RFP	RFP Objective	Status	Issued	Completed
2019R Utah RFP	Purchase new renewable energy for specific customers under Utah Schedule 32 or 34	Ongoing	March 2019	Ongoing
Renewable energy credits (Sale)	Excess system RECs	Ongoing	Based on specific need	Ongoing
2019 Capacity and Energy Supply RFP	Purchase capacity and energy supply	Ongoing	June 4, 2019	Ongoing
Renewable energy credits (Purchase)	Oregon compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Washington compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Ongoing	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Ongoing	Based on specific need	Ongoing

Demand Side Management (DSM) Resources

In 2018, through competitive procurement processes, the company selected vendors to continue and adaptively manage the successful, cost-effective delivery of its two largest Energy Efficiency programs: wattsmart Homes and wattsmart Business. PacifiCorp also competitively procured for Demand Response programs: Oregon Irrigation Load Control and Home Energy Reports. These delivery contracts support the delivery designs of existing programs.[27]

2017 Renewable Energy Credits RFP

PacifiCorp issued a 2017 Oregon Schedule 272 REC RFP in August 2017 seeking cost-competitive bids under Oregon Schedule 272 for individually negotiated arrangements for unbundled RECs from facilities in Oregon and Utah. As a result of discussions with customers, no transactions were completed pursuant to this RFP.

2017 Renewable RFP

PacifiCorp issued a Renewable RFP in September 2017 seeking cost-competitive bids for up to 1,270 MW of wind energy interconnecting with or delivering to PacifiCorp's Wyoming system and any additional wind energy located outside of Wyoming that will reduce system costs and provide net benefits for customers. As a result of the RFP, PacifiCorp has contracted to construct and/or procure three new wind projects – TB Flats I and II, Ekola Flats, and Cedar Springs – totaling 1,150 MW.

2017 Solar RFP

PacifiCorp issued a 2017 Solar Resource RFP in November 2017 seeking cost-competitive bids for solar energy interconnecting with or delivering to PacifiCorp's system that will reduce system

[27] Program information for Rocky Mountain Power can be found at energyvision2020.com/and programs for Pacific Power can be found at www.pacificpower.net/about/innovation-environment/energy-vision-2020.html.

costs and provide net benefits for customers. At the conclusion of the final shortlist evaluation process, PacifiCorp decided not to select any of the bids under this RFP.

2017 Market Resource RFP

PacifiCorp issued a 2017 Market Resource RFP in November 2017 seeking firm physical power delivered to PacifiCorp's western balancing authority area for the time period 2018 through 2020. No transactions were completed as a result of this RFP.

2018 Oregon Community Solar RFP

PacifiCorp issued a 2018 Oregon Community Solar RFP in July 2018 seeking cost-competitive bids for individual projects up to 3.0 MW of new greenfield, alternating current (AC) solar photovoltaic resources directly interconnecting with PacifiCorp's distribution or transmission system and located in PacifiCorp's Oregon service territory. The RFP is currently on hold while Oregon Community Solar Program rules, guidelines and timelines are furthered clarified and established within Public Utility Commission of Oregon proceedings.[28]

2018 Renewable Energy Credits RFP

PacifiCorp issued a 2017 Oregon Schedule 272 REC RFP in August 2018 seeking cost-competitive bids under Oregon Schedule 272 for individually negotiated arrangements for unbundled RECs from facilities within Pacific Power and Rocky Mountain Power service territories. As a result of discussions with customers, no transactions were completed as a result of this RFP.

2019 Renewable RFP - Utah

PacifiCorp issued a Renewable RFP in March 2019 on behalf of a select group of customers seeking cost-competitive bids for renewable projects constructed in Utah meeting the criteria established by the participating customers to meet their annual energy requirements. Projects must interconnect or be capable of delivery to PacifiCorp's system. Customers will contract for the project output through Utah's Schedule 32 or 34.[29] RFP is in progress with a target completion date in December 2019.

Renewable Energy Credits RFP (Sale)

On an ongoing basis, and based on availability, PacifiCorp issues short-term RFPs to sell RECs that are not required to be held and/or retired for meeting regulatory requirements, such as state RPS compliance obligations.

Renewable Energy Credits RFP (Purchase)

On an ongoing basis, and based on availability, PacifiCorp issues short-term RFPs to purchase RECs for PacifiCorp's Oregon, Washington and/or California state renewable portfolio standard compliance obligations.

[28] See Public Utility Commission of Oregon, Community Solar Program Implementation, Docket No. UM 1930, for more information.

[29] This Utah schedule information for Rocky Mountain Power can be found at: www.rockymountainpower.net/about/rates-regulation/utah-rates-tariffs.html

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp's planned transmission projects will facilitate a transitioning resource portfolio and will 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 major new transmission lines, these projects need to be planned in advance.
- 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.
- PacifiCorp requests acknowledgement of its plan to construct the Aeolus to Mona (Clover substation) Gateway South 500 kilovolt (kV) transmission line based on customer benefits and the inclusion of this segment in the 2019 PacifiCorp Integrated Resource Plan (IRP) preferred portfolio.
- While construction of the balance of future Energy Gateway segments (i.e., Gateway West, and Boardman to Hemingway) is beyond the scope of acknowledgement for this IRP, these segments are expected to deliver future benefits for our customers and for the region. Thus, continued permitting of these segments is warranted to ensure that PacifiCorp is well positioned to advance these projects at the appropriate time.

Introduction

PacifiCorp's bulk transmission network 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 meet aggregate electrical demand and customers' energy requirements at all times, taking into account scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Economic dispatch of resources within PacifiCorp's diverse system.
4. 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.
5. Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
6. Protection against market disruptions where limited transmission can otherwise constrain energy supply.
7. 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 growing energy needs of PacifiCorp's customers.

Regulatory Requirements

Open Access Transmission Tariff

PacifiCorp provides open access transmission and interconnection service in accordance with its OATT, as approved by the Federal Energy Regulatory Commission (FERC). Under the OATT, PacifiCorp plans and builds its transmission system to meet the needs of two different types of transmission customers: network customers and point-to-point customers. The OATT also obligates PacifiCorp to expand its system as needed to grant requests for generator interconnection 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 requests, as one factor 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 requested service. The required action is determined with each point-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.

point transmission service request through FERC-approved study processes that identify the transmission facilities needed to grant the request.

Requests for generator interconnection service can also drive the need for transmission network upgrades. Similar to the process for point-to-point requests, the OATT contains study procedures to determine the facilities needed to grant a request for new generator interconnection service.

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 Peak Reliability as the NERC Reliability Coordinator. Beginning in 2020, Peak Reliability will be disbanded and the California Independent System Operator (CAISO) will provide the Reliability Coordinator function 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 in order to meet NERC reliability criteria.

This chapter provides:

- Justification supporting acknowledgement of PacifiCorp's plan to construct Gateway South.
- Support for PacifiCorp's plan to continue permitting the balance of Gateway West and Boardman to Hemmingway;
- 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.

Wallula to McNary Update

The Wallula to McNary transmission project was energized at the end of January 2019 and the transmission customer began taking transmission service February 1, 2019. The project meets the requirement to provide the requested transmission service in accordance with the OATT and improves reliability of load served from the Wallula substation.

Aeolus to Bridger/Anticline Update

In 2018 PacifiCorp received the necessary state regulatory approvals, state and local permits, and private rights-of-way to construct the Aeolus-to-Bridger/Anticline sub-segment D.2 of Gateway West. Construction began in April 2019 and will be completed and placed in service by the end of 2020.

Request for Acknowledgement of Aeolus to Mona

The 2019 PacifiCorp IRP preferred portfolio includes the Aeolus-to-Mona (Clover substation) transmission segment (Energy Gateway South or Segment F). This segment is included in the preferred portfolio as a component of the least-cost, least-risk plan.

The 500 kV transmission segment extends 416 miles between the planned (as part of Gateway West sub-segment D.2) Aeolus substation near Medicine Bow, Wyoming, and the existing Clover substation located near Mona, Utah. PacifiCorp, with stakeholder involvement, has pursued permitting of the Energy Gateway South transmission project since 2008. In May 2016 the Bureau of Land Management (BLM) released its final Environmental Impact Statement (EIS) and issued their Record of Decision (ROD) in December of the same year. In May 2018 the U.S. Forest Service issued its ROD, completing the permitting on federal lands and providing a right-of-way grant for federal properties.

Leveraging transmission modeling improvements implemented in the 2019 IRP, the Aeolus-to-Mona transmission segment was made available as a transmission upgrade that could be endogenously selected by the System Optimizer (SO) model—the modeling tool used to develop a broad spectrum of resource portfolios during the portfolio-development phase of the IRP. In the initial phase of the portfolio-development process, PacifiCorp produced 35 unique resource portfolios to evaluate how the type, timing, location, and volume of new resources and transmission upgrades changed in response to different planning assumptions (i.e., coal retirements, market prices, carbon dioxide (CO_2) prices). The Aeolus-to-Mona transmission segment was endogenously selected by the SO model to come online by the end of 2023 in 34 out of these 35 resource portfolios, and was selected to come online by the end of 2023 in all subsequent resource portfolios developed to refine cost-and-risk analysis for top-performing cases. Based on the IRP analysis, the Aeolus-to-Mona transmission segment will be placed into service by the end of 2023, subject to completion of local permitting and private rights-of-way acquisitions. To align development of the Aeolus-to-Mona transmission segment with additional renewable generation projects that will further decarbonize PacifiCorp's portfolio and to provide full line rating capacity on Gateway West and South, the company requests the Aeolus-to-Mona transmission segment be acknowledged in this IRP.

Factors Supporting Acknowledgement

Acknowledgment of the Aeolus-to-Mona transmission segment is supported by the extensive analysis that led to the inclusion of the transmission line in the 2019 IRP preferred portfolio. This transmission segment will allow PacifiCorp to implement system improvements, supports the full capacity rating for Gateway South and West and enables the addition of incremental Wyoming wind resources to support customer needs and deliver value for customers in the most cost-effective way. Timing of construction is driven by the phase-out schedule of federal production tax credits (PTCs), particularly the 2023 in-service requirements for 40 percent PTC eligibility, and potential risk associated with the termination of the BLM permit for non-use. In addition to

supporting renewable resource additions in PacifiCorp's generation portfolio, qualifying them for PTCs, the new transmission segment will increase transfer capability out of eastern Wyoming.

The addition of the Aeolus-to-Mona transmission segment further improves the reliability of PacifiCorp's transmission system in the following ways:

- Provides a parallel path to the Gateway West – Sub-segment D.2 Project (Aeolus-to-Bridger/Anticline 500 kV line) improving the reliability of the 230 kV transmission system in Wyoming for the loss of either 500 kV line.
- Strengthens the PacifiCorp transmission system (increased fault duty) by interconnecting the geographically diverse areas of eastern Wyoming and southern Utah together, allowing additional generation resources to be connected.
- Improves grid reliability by providing better operational control of the backbone transmission system by interconnecting two areas of the PacifiCorp transmission system that are abundant in two different forms of renewable resources, specifically wind rich eastern Wyoming with the solar rich area of southern Utah.
- Provides anticipated improvements in eastern Utah reliability by providing a potential future high voltage source and power delivery option to meet the projected oil expansion and corresponding load growth (Ashley, Vernal).
- Improves the southern Utah transmission system reliability by providing congestion relief on the 345 kV lines during outage conditions.
- Supports PacifiCorp's NERC TPL-001-4 transmission system reliability efforts, which are necessary to improve grid reliability performance.
- Assists PacifiCorp in meeting its OATT obligations to interconnect new generation.

Completion of the new transmission segment realizes the full 1,700 MW rating of Gateway South allowing the addition of up to 1,920 MW of renewable resources added to the system. 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.

PacifiCorp's preferred portfolio includes nearly 11,000 MW of new wind and solar resources expected to come online in the 2020-2038 timeframe, which reflects a least-cost, least-risk mix of resources that requires incremental infrastructure investment to serve PacifiCorp's customers cost effectively and reliably.

Gateway West – Continued Permitting

In addition to the Windstar-to-Populus line (Energy Gateway Segment D), the Gateway West transmission project also includes the Populus-to-Hemingway transmission segment (Energy Gateway Segment E). In a future IRP, PacifiCorp will support a request for acknowledgement to construct the balance of Gateway West. While PacifiCorp is not requesting acknowledgement of a plan to construct these segments in this IRP, the company will continue to permit the projects.

Windstar to Populus (Segment D)

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

- D1—A single-circuit 230-kV line that will run approximately 75 miles between the existing Windstar substation in eastern Wyoming and the Aeolus substation that is currently under construction near Medicine Bow, Wyoming, which includes a loop-in to the existing Shirley Basin 230-kV substation;

Figure 4.1 - Segment D

- D2—A single-circuit 500-kV line that is currently under construction running approximately 140 miles from the Aeolus substation (under construction) to a new annex substation (Anticline, also currently under construction) near the existing Bridger substation in western Wyoming; and

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

Populus to Hemingway (Segment E)

Figure 4.2 - 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.

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

Under the National Environmental Policy Act, the BLM has completed the EIS for the Gateway West project. The BLM released its final EIS on April 26, 2013, followed by the ROD on November 14, 2013, providing a right-of-way grant for all of Segment D and most of Segment E of the project. The BLM 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. A ROD for these final sections of Segment E was issued on January 19, 2017 and a right-of-way grant was issued on August 8, 2018.

Plan to Continue Permitting – Gateway West

The Gateway West transmission projects continue to offer benefits under multiple, future resource scenarios. To ensure that PacifiCorp 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.

Plan to Continue Permitting – Boardman to Hemingway

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.

Idaho Power's 2019 IRP identifies 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.

Permitting Update

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 approved route is the agency-preferred alternative identified in the final EIS and proposed land-use plan amendments.

For all lands crossed in Oregon, Idaho Power must receive a site certificate from the Energy Facility Siting Council (EFSC) prior to constructing and operating the proposed transmission line. The Oregon Department of Energy (ODOE) serve as staff members to EFSC facilitating the review of the site certificate application process. ODOE and EFSC both review Idaho Power's application to ensure compliance with state energy facility siting standards

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.

Benefits

The existing transmission path between the Pacific Northwest and Intermountain West regions is fully used during key operating periods, including winter peak periods in the Pacific Northwest and summer peak in the Intermountain West. PacifiCorp has invested in the permitting of the B2H project because of the strategic value of connecting the two regions. As a potential owner in the project, PacifiCorp would be able to use its bidirectional capacity to increase reliability and to enable more efficient use of existing and future resources for its customers. The following lists additional B2H benefits:

- **Customers**: PacifiCorp continues to invest to meet customers' needs, making only critical investments now to ensure future reliability, security, and safety. The B2H project will bolster reliability, security, and safety for PacifiCorp customers as the regional supply mix transitions.
- **Renewables**: The B2H project has been identified as a strategic project that can facilitate the transfer of geographically diverse renewable resources, in addition to other resources, across PacifiCorp's two balancing authority areas. Transmission line infrastructure, like

B2H, is needed to maintain a robust electrical grid while integrating clean, renewable energy resources across the Pacific Northwest and Mountain West states.

- **Regional Benefit**: PacifiCorp, as a member of the regional planning entity Northern Tier Transmission Group (NTTG), supports the inclusion of B2H in the NTTG regional plan. From a regional perspective, the B2H project is a cost-effective investment that will provide regional solutions to identified regional needs.
- **Balancing Area Operating Efficiencies**: PacifiCorp operates and controls two balancing areas. After the addition of B2H and portions of Gateway West, more transmission capacity will exist between PacifiCorp's two balancing areas, providing the ability to increase operating efficiencies. B2H will provide PacifiCorp 300 MW of additional west-to-east capability and 600 MW of east-to-west capability to move resources between PacifiCorp's two balancing authority areas.
- **Regional Resource Adequacy**: PacifiCorp is participating in the ongoing effort to evaluate and develop a regional resource adequacy program with other utilities that are members of the Northwest Power Pool. The B2H project is anticipated to provide incremental transmission infrastructure that will broaden access to a more diverse resource base, which will provide opportunities to reduce the cost of maintaining adequate resource supplies in the region.
- **Grid Reliability and Resiliency**: The Midpoint-to-Summer Lake 500-kV transmission line is the only line connecting PacifiCorp's east and west control areas. The loss of this line has the potential to reduce transfers by 1,090 MW. When B2H is built, the new transmission line will provide redundancy by adding an additional 1,000 MW of capacity between the Hemingway substation and the Pacific Northwest. This additional asset would mitigate the impact when the existing line is lost.
- **Oregon and Washington Renewable Portfolio Standards and Other State Legislation**: New legislation and rules for recently passed legislation are being developed to meet state-specific policy objectives that are expected to drive the need for additional renewable resources. As these laws are enacted and rules are developed, PacifiCorp will evaluate how the B2H transmission line can help facilitate meeting state policy objectives by providing incremental access to geographically diverse renewable resources and other flexible capacity resources that will be needed to maintain reliability. PacifiCorp believes that investment in transmission infrastructure projects, like B2H and other Energy Gateway segments, are necessary to integrate and balance intermittent renewable resources cost effectively and reliably.
- **EIM**: PacifiCorp was a leader in implementing the western energy imbalance market (EIM). The real-time market helps optimize the electric grid, which lowers costs, enhances reliability, and more effectively integrates resources. PacifiCorp believes the B2H project could help advance the objectives of the EIM and has the potential of benefitting PacifiCorp customers and the broader region.

Next Steps

Given the extensive list of benefits noted above, PacifiCorp is committed to participating in the B2H project in accordance with the terms of the Joint Funding Permitting Agreement through the final Oregon Department of Energy Facilities Siting Council's permitting process and will continue 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.

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. Please refer to the regional maps of wind, solar, biomass, and geothermal potential available on PacifiCorp's Energy Gateway project website to see an overlay of the Energy Gateway project and renewable resource potential.[2] 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:

[2] www.pacificorp.com/transmission/transmission-projects/energy-gateway.html

- ***Northwest Transmission Assessment Committee (NTAC)***
  The NTAC was the sub-regional transmission planning group representing the northwest region, preceding Northern Tier Transmission Group and ColumbiaGrid. The NTAC developed long-term transmission options for resources located within the provinces of British Columbia and Alberta, and the states of Montana, Washington, and Oregon to serve Pacific Northwest loads and northern California.

- ***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 and Sigurd to Red Butte.
  - 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 coal 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."

- ***Western Regional Transmission Expansion Partnership (WRTEP)***
  The WRTEP was a group of six utilities working with four western governors' offices to evaluate the proposed Frontier Transmission Line. The Frontier Line was proposed to connect California and Nevada to Wyoming's Powder River Basin through Utah. The utilities involved were PacifiCorp, Nevada Power, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Sierra Pacific Power.

- ***Northern Tier Transmission Group Transmission Planning Reports***

In the 2016-2017 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 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, and 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 NTTG and WECC's RAC.

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

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

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 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 the Mona-to-Oquirrh project. In November 2013, the B LM 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.

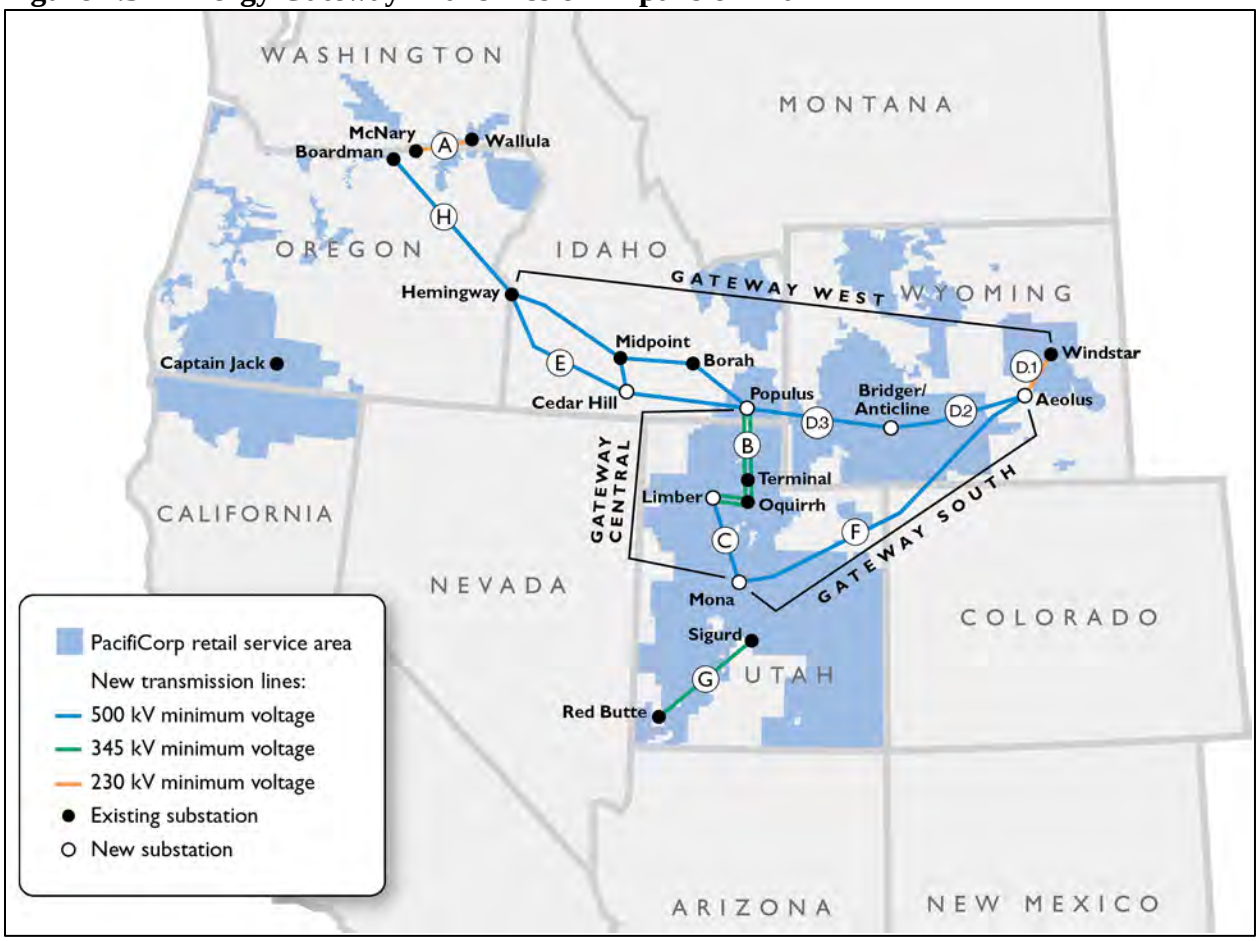
In December 2016, the BLM issued its ROD and right-of-way grant for the Gateway South project.

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.

Finally, the timing of Energy Gateway segments is regularly assessed and adjusted. While permitting delays have played a significant role in the adjusted timing of some segments (e.g., Gateway West, Gateway South, and Boardman to Hemingway), PacifiCorp has been proactive in deferring in-service dates as needed due to permitting schedules, moderated load growth, changing customer needs, and system reliability improvements.

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

Figure 4.3 – Energy Gateway Transmission Expansion Plan



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

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: Construction complete • 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: 2024
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	75 mi	• Status: permitting underway • Scheduled in service: 2023 earliest
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: under construction • Scheduled in service: 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in service: 2024 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2024 earliest
(F) Aeolus-Mona	500 kV single circuit	400 mi	• Status: permitting underway • Scheduled in service: 2023
(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: sponsor driven

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 155 grid operating procedures and 17 special protection schemes to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the EIM since November 2014. The EIM provides for more efficient dispatch of participating resources in real-time through an automated system that dispatches generation across the EIM footprint (collectively, EIM Area), which currently includes:

- PacifiCorp east and west balancing authority areas
- NV Energy
- Puget Sound Energy
- Arizona Public Service
- Portland General Electric

- Idaho Power Company
- Powerex Corporation in the BC Hydro balancing authority area
- Balancing Authority of Northern California with its member the Sacramento Municipal Utility District
- CAISO balancing authority area (collectively, EIM Area)

Entities scheduled to join the EIM include Seattle City Light, Los Angeles Department of Water and Power, and Salt River Project (April 2020), NorthWestern Energy (April 2021), and Public Service of New Mexico (April 2021 pending state commission approval).

By broadening the pool of lower-cost resources that can be accessed to balance load system requirements, reliability is enhanced and system costs are reduced 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.

Transmission System Improvements Placed In-Service Since the 2017 IRP

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area
   - Installed backup 345-kV bus differential relays at Jim Bridger substation located in Wyoming
     - Project driver was to correct NERC Standard TPL-001-4 Category P5 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment resulting from a fault plus relay failure to operate event.
     - Benefits include mitigating the risk of thermal overloads and voltage issues in the surrounding area resulting from the failure of the primary 345-kV bus differential relay protection to operate, and the resolution of the NERC Standard TPL-001-4 Category P5 deficiency.
2. Goshen Idaho Area
   - Reconstructed the Goshen-Jefferson 161-kV line located in Idaho
     - Project driver was projected load growth at Jefferson substation that required increasing the capacity of the 161-kV line and eliminating existing clearance issues on the 161-kV line from Goshen-to-Jefferson substation.
     - Benefits include supporting projected load growth in the area by increasing the capacity of the 161-kV transmission line and eliminating line clearance issues which allows operation of the line at full capacity.
   - Installed a new remedial action scheme (RAS) in the Goshen/Rigby area of Idaho
     - Project driver was the risk of losing the 345-kV source at Goshen Substation that would result in thermal overload and severe low voltage conditions on other underlying transmission lines in the Goshen/Rigby area. The previous protection scheme would have tripped all load and generation in the area which was anticipated to be up to 700 MW and 650 MW, respectively.
     - Benefits include shedding less load and generation than the previous RAS (load up to 450 MW and generation up to 80 MW) to prevent multiple thermal overload and low voltage conditions and improved the restoration process by

making it less complicated than the previous protection scheme which dropped all load and generation in the area.

- Purchased a spare 345-161 kV transformer for Goshen substation in Idaho
  - Primary driver is to protect against experiencing a single contingency event (N-1) for the failure of one of the 700 megavolt-ampere (MVA), 345-161 kV transformers at Goshen substation that would cause thermal overload on the remaining transformer during heavy summer load periods and could result in the load shedding of up to 250 MW of load in the area for extended periods of time since there were no system spare transformers at this voltage class and capacity.
  - Benefits include mitigating the risk of thermal overload on the remaining 700 MVA, 345-161 kV transformer and not having to shed up to 250 MW of load for extended periods of time during heavy summer loading conditions.
- Installed shunt capacitors at Rigby and Sugarmill substations located in Idaho
  - Primary driver was to correct NERC Standard TPL-001-4 Category P1-2 deficiency identified in PacifiCorp's 2016 NERC TPL Assessment and the 2016 Goshen Area Study resulting in low voltage issues caused by the loss of a 161-kV line (N-1).
  - Benefits include improving the voltage profile under normal and outage conditions, resolving low voltage and voltage deviation issues, reducing load shedding risk under normal operating conditions, mitigating consequential load loss of up to 150 MW, improving reliability to the Rigby-Sugarmill area customers, and resolution of NERC TPL-001-4 Category P1-2 deficiency.

3. Southeast Idaho Area
   - Replaced an existing bus tie oil breaker with a SF6 breaker and added a circuit switcher in series with the breaker at the Treasureton 138-kV substation located in Idaho
     - Project driver was to correct NERC Standard TPL-001-4 Category P2-4 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment resulting from a potential stuck breaker event that prevents the bus tie to operate to clear a fault. The P2-4 contingency event that would result in thermal overloads beyond the emergency rating of several 138 kV lines in that area.
     - Benefits include mitigating the risk of thermal overloads and voltage issues, eliminating the potential loss of load at the Treasureton substation of up to 465 MW, and resolution of the NERC TPL-001-4 Category P2-4 deficiency.
4. Ogden Utah Area
   - Energized one circuit of the 230-kV Ben Lomond-to-Parrish line as a three-terminal 138-kV line from Ben Lomond to Syracuse and Parrish located in Utah
     - Project driver was to correct the NERC Standard TPL-003 Category C3 deficiency that was identified in PacifiCorp's 2013 NERC TPL Assessment that caused by the loss of any two bulk transmission elements under peak load conditions.

    - Benefits include mitigating the risk of thermal overloads and voltage issues, mitigating the potential load shedding of up to 180 MW in the Ogden area, and the resolution of the NERC TPL-003 Category C3 deficiency.

- Installed a second 700 MVA 345/138 kV transformer at Syracuse substation located in Utah
    - Project driver was to correct NERC Standard TPL-001-4 Category P1, P6 and P7 deficiencies identified in PacifiCorp's 2015 NERC TPL Assessments resulting in a single contingency event (N-1) and multiple contingency events (P6 and P7).
    - Benefits include mitigating the risk of thermal overloads and low voltage issues, eliminating the risk of preemptive load shedding up to 30 MW, improving transmission reliability for customers in the Ogden area, and resolution of the NERC TPL-001-4 Category P1 deficiencies and resolves nearly half the number of identified NERC TPL-001-4 Category P6 and P7 deficiencies (Operating procedures are in place to address the non-resolved P6 and P7 deficiencies that were not corrected by the implementation of this project).
- Installed a new RAS at El Monte substation and line closing for Riverdale–Gordon Avenue–Parrish 138-kV lines in Utah
    - Project driver was to correct NERC Standard TPL-001-4 Category P2, P6 and P7 deficiencies identified in PacifiCorp's 2016 NERC TPL Assessment that could cause thermal overload issues on multiple 138-kV lines in the Ogden area.
    - Benefits include mitigating the risk of thermal overloads, improving reliability to the 138-kV system, optimizing the load shed levels of the new RAS, and resolving NERC TPL-001-4 Category P2, P6 and P7 deficiencies.

5. Salt Lake Valley Area
    - Replaced breakers identified as over-dutied with higher-capability breakers at MidValley substation in Utah
        - Project driver was to correct NERC Standard TPL-001-4 Requirement R2.3 deficiencies identified in PacifiCorp's 2015 NERC TPL Assessment resulting in the identification of three 138-kV over-dutied breakers at MidValley substation.
        - 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.
6. Park City Utah Area
    - Constructed a 138-kV line from Croydon substation to Silver Creek substation located in Utah
        - Project drivers were projected load growth and reliability improvements which required an additional 138-kV source into the Park City area.
        - Benefits are the additional a 138-kV source into the area, additional capacity to address projected load growth, and improved transmission reliability.
7. Utah Valley Area

- Installed backup bus differential relays at Camp Williams substation located in Utah
    - Project driver was to correct NERC Standard TPL-001-4 Category P5 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment resulting from a fault plus relay failure to operate event.
    - Benefits include mitigating the risk of thermal overloads and voltage issues in the surrounding area resulting from the failure of the primary 345-kV bus differential relay protection to operate and the resolution of the NERC Standard TPL-001-4 Category P5 deficiency.
- Installed a new bay with a breaker and half scheme at Spanish Fork substation located in Utah
    - Project driver was to correct NERC Standard TPL-003 Category C2 deficiency identified in PacifiCorp's 2013 NERC TPL Assessment for a potential stuck breaker event that prevents the bus-tie breaker to operate to clear a fault.
    - Benefits include mitigating the risk of thermal overloads and voltage issues, and eliminating the potential loss of the entire Spanish 138-kV substation load of up to 270 MW, and resolution of the NERC TPL-003 Category C2 deficiency.

8. Southwest Utah Area
    - Energized the Red Butte-St. George 345-kV line at 138 kV located in Utah
        - Project driver was to correct NERC Standard TPL-001-4 Category P6 and P7 deficiencies identified in PacifiCorp's 2015 NERC TPL Assessment resulting in multiple contingency events (N-1-1 and N-2) that would impact 138-kV lines between Red Butte/Central and St. George substations during heavy summer load conditions.
        - Benefits include adding a fourth Central/Red Butte to St. George 138-kV line that increased capacity into St. George substation, improved 138-kV reliability in the area, eliminated the need for preemptive loading shedding under an N-1-1 outage condition up to 170 MW, and resolved the NERC Standard TPL-001-4 Category P6 and P7 deficiencies.
9. East Utah Area
    - Installed 3.6 megavolt-ampere-reactive (MVAr) capacitor banks at Maeser and Vernal substations located in Utah
        - Project driver was to correct NERC Standard TPL-001-4 Category P1 and P2 deficiencies identified in PacifiCorp's 2016 NERC TPL Assessment resulting for the loss of a 138-kV line (P1) and for circuit break/bus faults (P2) that result in low voltage in the Vernal area.
        - Benefits include mitigating the risk of low voltage issues and resolution of the NERC Standard TPL-001-4 Category P1 and P2 deficiencies.

PacifiCorp West (PACW) Control Area

1. Yakima Washington Area
    - Rebuilt the 115-kV main and transfer bus into a breaker and half scheme at the Union Gap substation in Washington

    - Project driver was to correct NERC Standard TPL-003 Category C deficiencies identified in PacifiCorp's 2013 NERC TPL Assessment for a 115 kV bus section fault or breaker failure with protection system failure.
    - Benefits include mitigating the risk of thermal overloads and voltage issues, eliminating the risk of shedding up to 500 MW of load, and resolution of the NERC TPL-003 Category C deficiencies.
  - Replaced conductor on the Moxee-Hopland section of the Moxee-Union Gap 115-kV line located in Washington
    - Project driver was to correct NERC Standard TPL-001-4 Category P1 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment resulting from a single contingency event (N-1) for the loss of a 230-kV transmission line.
    - Benefits include mitigating the risk of thermal overloads, increasing capacity of the 115-kV line, improving transmission reliability, and resolution of the NERC TPL-001-4 Category P1 deficiency.
2. Portland Oregon Area
  - Rebuilt the 230-kV portion of the Troutdale substation, located in Oregon, into a six breaker ring bus configuration
    - Project driver was to correct NERC Standard TPL-002 deficiency for the loss of a single 230 kV line and NERC Standard TPL-003 for multiple contingency (N-1-1 and N-2) outages to 230-kV lines that were identified in the PacifiCorp's 2011 NERC TPL Assessment.
    - Benefits include mitigating the risk of thermal overloads, eliminating the risk of shedding load in preparation of the second contingency for an N-1-1 outage, and resolution of the NERC TPL-002 and TPL-003 deficiencies.
  - Converted portions of Portland, Oregon area transmission network to 115 kV from 57 kV and 69 kV
    - Project drivers are projected load growth, needed additional capacity, and transmission reliability improvement needs in the Portland area.
    - Benefits include the elimination of portions of the old 57-kV and 69-kV systems, increasing the 115-kV network, adding additional capacity to address projected load growth and reliability improvement to the transmission network.
3. Grant Pass Oregon Area
  - Replaced three 230-115 kV 125 MVA transformers with two 230-115 kV 250 MVA transformers at Grants Pass substation in Oregon
    - Project driver was to correct NERC Standard TPL-002 deficiency for the loss of a single 230-kV line and NERC Standard TPL-003 deficiencies for multiple contingency (N-1-1 and N-2) outages to 230-kV lines that were identified in PacifiCorp's 2013 NERC TPL Assessment.
    - Benefits include mitigating the risk of thermal overloads, eliminating the risk of shedding load in preparation of the second contingency for an N-1-1 outage, and resolution of the NERC TPL-002 and TPL-003 deficiencies.
4. Klamath Falls Oregon Area

- Constructed the new Snow Goose 500-230 kV substation located in Oregon
    - Project driver was to correct NERC Standard TPL-001-1 Category B deficiency for the single contingency of the loss of the existing 500-230 kV transformer and TPL-003 Category C deficiencies for multiple N-1-1 and N-2 outages that were identified in PacifiCorp's 2012 NERC TPL Assessment.
    - Benefits include mitigating the risk of thermal overloads and voltage issues, eliminates the risk of shedding load in preparation of the second contingency for an N-1-1 outage, and resolves the NERC TPL-001-1 Category B and TPL-003 Category C deficiencies.

5. Yreka California Area
    - Replaced the existing 115-69 kV transformer at Weed substation with a 50 MVA load tap changer (LTC) unit located in California
        - Project driver was to improve 69-kV voltage regulation by changing out an old 115-69 kV transformer at Weed Junction substation that had its no-load tap changer locked in place due to the high risk of causing internal transformer fault if operated. The new replacement 115-69 kV LTC transformer was installed at the nearby Weed substation.
        - Benefits include improved voltage control of the local 69-kV system, improved transformer reliability, and ability to use load drop compensation to improve transmission voltage profile.

Planned Transmission System Improvements

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area
    - Upgrade the 345-230 #2 transformer at Jim Bridger substation in Wyoming
        - Project driver is 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 results 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
    - Install a third 345-161 kV transformer at Goshen substation located in Idaho
        - Project driver is 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.
    - Install a new 161-kV line from Goshen to Sugarmill and then from Sugarmill to Rigby substations located in Idaho

    - Project driver is 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 and then from Sugarmill to Rigby substation 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.
- Rebuild and convert an existing 69-kV line to 161-kV to establish a new 161-kV source at Rexburg substation in Idaho
    - Project driver is 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.

3. Salt Lake Valley Area
    - Install a new circuit switcher in series with the bus-tie circuit breaker at 90th South substation located in Utah
        - Project driver is to correct NERC Standard TPL-001-4 Category P2-4 deficiency identified in PacifiCorp's 2017 NERC TPL Assessment for a bus tie breaker internal fault event that results in the loss of the entire 90th South 138-kV substation.
        - Benefits include mitigating the risk of thermal overloads and voltage issues, and eliminating the potential loss of load at the entire 90th South 138-kV South substation for a bus tie failure event, and resolution of the NERC TPL-001-4 Category P2-4 deficiency.
4. Park City Utah Area
    - Install a 9-mile, 138-kV transmission line between Midway and Jordanelle substations in Utah
        - Project drivers are 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.
5. Utah Valley Area
    - Upgrade the 345-138 kV transformer at Spanish Fork substation located in Utah
        - Project driver is to correct NERC Standard TPL-001-4 Category P1 and P3 deficiencies identified in PacifiCorp's 2017 NERC TPL Assessment resulting from an outage of Spanish Fork 345-138 kV transformer #4 (N-1) and multiple

double contingency outages (N-1-1) that result in thermal overloads on numerous substation transformers and transmission lines.

- Benefits include mitigating the risk of thermal overloads and low voltage issues, additional capacity to address projected load growth, improved transmission reliability and resolution of the NERC TPL-001-4 Category P1 and P3 deficiencies.

6. East Utah Area
   - Construct the new Naples 138-12.5 kV substation located in Utah
     - Project driver is to correct NERC Standard TPL-001-4 Category P6 deficiencies identified in PacifiCorp's 2016 NERC TPL Assessment resulting in multiple double contingencies causing low 138-kV system voltages in the Vernal area.
     - Benefits include mitigating the risk of low voltage issues and resolution of the NERC Standard TPL-001-4 Category P6 deficiencies.
7. Utah & Idaho – Upgrade Program – Backup Bus Differential Relays
   - Install backup bus differential relays at various substations located in Utah and Idaho
     - Project driver is 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 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.
8. Utah, Idaho & Wyoming - Upgrade Program – Replace Over-dutied Circuit Breakers
   - Replace breakers identified as over-dutied with higher-capability breakers in various substations located in Idaho, Utah, and Wyoming
     - Project driver is 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

PacifiCorp West (PACW) Control Area

1. Yakima Washington Area
   - Construct a new 230-kV transmission line from BPA's Vantage substation to PacifiCorp's Pomona Heights substation located in Washington
     - Project driver is to correct the NERC Standard TPL-002 deficiency identified in PacifiCorp's 2011 TPL Assessment for the loss of a single 230-kV line.

    - Benefits include mitigating the risk of thermal overloads and low voltage issues, adding additional capacity to address projected load growth, improving transmission reliability and resolution of the NERC TPL-002 deficiencies.

- Construct a new 115-kV transmission line from Outlook substation to Punkin Center substation located in Washington
    - Project driver is 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.

2. Walla Walla Washington Area
    - Replace the existing 115-69 kV, 20 MVA transformer with a 115-69 kV, 50 MVA transformer at Dry Gulch substation located in Washington
        - Project driver is to correct NERC Standard TPL-001-4 Category P2 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment for a 115-kV bus fault at Dry Gulch substation.
        - Benefits include having 69-kV capacity and voltage regulation capability to operate in a normal open configuration to eliminate thermal overloads and low voltage conditions, eliminating the 69-kV loop in parallel with the 230-kV and 500-kV main grid system that impacted the 69-kV system for outages on the main grid system, removing the Tucannon 69-kV line from the WECC Path 6 definition, and resolving the NERC TPL-001-4 P2 deficiency.
3. Albany/Corvallis Oregon Area
    - Replace conductor on the 115-kV line between Hazelwood substation and BPA's Albany substation and construct a new 115-kV ring bus at Hazelwood substation all located in Oregon
        - Project driver is 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.
4. Medford Oregon Area
    - Construct one new 500-230 kV substation called Sams Valley located in Oregon
        - Project driver is to correct NERC Standard TPL-002 for the loss of a single 230-kV line and NERC Standard TPL-003 for the N-1-1 and N-2 outages to 230-kV lines that were identified in PacifiCorp's 2010 NERC TPL Assessment, 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-002 and TPL-003 deficiencies.

- Expand the RAS at Meridian substation located in Oregon
    - Project driver is 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.

5. Yreka California Area
    - Install an additional 115-69 kV transformer at Yreka substation located in California
        - Project driver is to correct low voltage conditions under normal operating conditions during heavy summer loading periods due to inadequate voltage regulation on the 69-kV system served from Yreka substation, as identified in the 2013 Yreka-Mt Shasta Area Study.
        - Benefits include the ability to provide 69-kV voltage regulation by the new 115-69 kV transformers load tap changer , allows the use of load drop compensation feature to further improve the transmission voltage profile over the long term, and making the exiting non-LTC transformer available as an installed spare for immediate service restoration when needed.
6. Oregon – Upgrade Program – Replace Over-dutied Circuit Breakers
    - Replace breakers identified as over-dutied with higher-capability breakers at Lone Pine Substation in Oregon
        - Project driver is 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.

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 NERC and WECC reliability standards.

CHAPTER 5 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

- On both a capacity and energy basis, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability at the time of the coincident system summer and winter peak periods.
- For capacity expansion planning, PacifiCorp uses a 13 percent target planning reserve margin (PRM) applied to the company's obligation, which is calculated as projected load less private generation, less energy efficiency savings (Class 2 demand-side management (DSM)), and less interruptible load.
- A 2018 Private Generation Long-Term Resource Assessment (2019-2038) study prepared by Navigant Consulting, Inc. 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 2019 IRP load and resource balance treats base case private generation penetration levels as a reduction in load.
- After accounting for load reductions from private generation and energy efficiency savings from the preferred portfolio, PacifiCorp's system coincident peak load is forecasted to grow at a compound annual growth rate of 0.10 percent over the period 2019 through 2038 (0.64 percent without incremental energy efficiency from the preferred portfolio). On an energy basis, PacifiCorp expects system-wide average load growth of 0.06 percent per year from 2019 through 2038 (0.73 percent without incremental energy efficiency savings from the preferred portfolio).
- After accounting for the 13 percent target PRM, load growth, coal unit retirements from the preferred portfolio, and after incorporating future energy efficiency savings from the preferred portfolio, PacifiCorp's system is capacity deficient over the summer peak throughout the twenty-year planning period and is capacity deficient over the winter peak beginning 2024.
- When accounting for these same factors and the level of potential market purchases, front office transactions (FOTs), assumed in the 2019 Integrated Resource Plan (IRP), PacifiCorp's system is capacity deficient over the summer peak beginning 2028 and is capacity deficient over the winter peak beginning 2029.

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 as a whole 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 and energy are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, with and without available FOTs, assumed coal unit retirements and incremental new energy efficiency savings from the 2019 IRP 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 2019 IRP relies on PacifiCorp's September 2018 load forecast. Table 5.1 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 0.90 percent over the period 2019 through 2038.

Table 5.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency and Private Generation (MW)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System	10,284	10,425	10,549	10,671	10,788	10,934	11,012	11,057	11,149	11,261
	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
System	11,362	11,469	11,575	11,696	11,809	11,723	11,834	11,946	12,078	12,193

Existing Resources

On a system coincident basis, PacifiCorp is a summer-peaking utility. For the forecasted 2019 summer coincident peak, PacifiCorp owns or contracts for resources to meet expected system summer peak capacity. Note that capacity ratings in the following tables provide resource capacity value at nameplate, rounded to the nearest megawatt.

Thermal Plants

Table 5.2 lists PacifiCorp's existing coal-fueled plants and Table 5.3 lists existing natural-gas-fueled plants. End of life year dates reflect those assumed in the preferred portfolio.

Table 5.2 – Coal-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	End of Life Year	Nameplate Capacity (MW)
Cholla 4	100	Arizona	2020	387
Colstrip 3	10	Montana	2027	74
Colstrip 4	10	Montana	2027	74
Craig 1	19	Colorado	2025	82
Craig 2	19	Colorado	2026	82
Dave Johnston 1	100	Wyoming	2027	99
Dave Johnston 2	100	Wyoming	2027	106
Dave Johnston 3	100	Wyoming	2027	220
Dave Johnston 4	100	Wyoming	2027	330
Hayden 1	24	Colorado	2030	44
Hayden 2	13	Colorado	2030	33
Hunter 1	94	Utah	2042	418

Hunter 2	60	Utah	2042	269
Hunter 3	100	Utah	2042	471
Huntington 1	100	Utah	2036	459
Huntington 2	100	Utah	2036	450
Jim Bridger 1	67	Wyoming	2023	354
Jim Bridger 2	67	Wyoming	2028	359
Jim Bridger 3	67	Wyoming	2037	349
Jim Bridger 4	67	Wyoming	2037	353
Naughton 1	100	Wyoming	2025	156
Naughton 2	100	Wyoming	2025	201
Naughton 3*	100	Wyoming	2019	0
Wyodak	80	Wyoming	2039	268
TOTAL – Coal				**5,638**

* Naughton 3 coal generation ended January 30, 2019. The preferred portfolio converts Naughton 3 to gas in 2020 through 2029.

Table 5.3 – Natural-Gas-Fueled Plants

Natural Gas -fueled	PacifiCorp Percentage Share (%)	State	Assumed End of Life Year	Nameplate Capacity (MW)
Chehalis	100	Washington	2043	491
Currant Creek	100	Utah	2045	545
Gadsby 1	100	Utah	2032	64
Gadsby 2	100	Utah	2032	69
Gadsby 3	100	Utah	2032	105
Gadsby 4	100	Utah	2032	40
Gadsby 5	100	Utah	2032	40
Gadsby 6	100	Utah	2032	40
Hermiston	100	Oregon	2036	234
Lake Side	100	Utah	2047	551
Lake Side 2	100	Utah	2054	644
TOTAL – Natural Gas				**2,821**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 3,908 MW of wind resources. Table 5.4 shows existing wind facilities owned by PacifiCorp, while Table 5.5 shows existing wind power purchase agreements.

Table 5.4 – Owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)
Foote Creek I *	WY	32
Leaning Juniper	OR	101
Goodnoe Hills East Wind	WA	94
Marengo	WA	140
Marengo II	WA	70
Glenrock Wind I	WY	99
Glenrock Wind III	WY	39
Rolling Hills Wind	WY	99
Seven Mile Hill Wind	WY	99
Seven Mile Hill Wind II	WY	20
High Plains	WY	99
McFadden Ridge 1	WY	29
Dunlap 1	WY	111
Pryor Mountain **	MT	240
Cedar Springs II***	WY	200
Ekola Flats ***	WY	250
TB Flats ***	WY	500
TOTAL – Owned Wind		**2,222**

* Net total capacity for Foote Creek 1 is 40 MW.

** Wind facility not part of EV 2020. In service December 31, 2020.

*** EV 2020 in service by December 31, 2020.

Table 5.5 – Non-Owned Wind Resources

Power Purchase Agreements / Exchanges	State	PPA or QF	Capacity (MW)
Cedar Springs Wind ***	WY	PPA	200
Cedar Springs III *	WY	PPA	120
Combine Hills	OR	PPA	41
Foote Creek IV	WY	PPA	17
Rock River I	WY	PPA	50
Stateline Wind	OR / WA	PPA	175
Three Buttes Wind Power (Duke)	WY	PPA	99.0
Top of the World	WY	PPA	200
Wolverine Creek	ID	PPA	65
Chopin	WA	QF	10
Foote Creek II	WY	QF	2
Foote Creek III	WY	QF	25
Latigo Wind	UT	QF	60
Mariah Wind	OR	QF	10
Meadow Creek Project – Five Pine	ID	QF	40.0
Meadow Creek Project – North Point	ID	QF	80
Monticello Wind	UT	QF	79
Mountain Wind Power I	WY	QF	61
Mountain Wind Power II	WY	QF	80
Orchard Wind	WA	QF	40
Oregon Wind Farms I & II	OR	QF	65
Orem Family Wind	OR	QF	10.0
Pioneer Wind Park I	WY	QF	80
Power County Wind Park North	ID	QF	23

Power County Wind Park South	ID	QF	23
Spanish Fork Wind Park 2	UT	QF	19
Three Mile Canyon	WA	QF	10
Toole Army Depot	UT	QF	3
Small QF	WY	QF	0.2
TOTAL – Purchased Wind			**1,686**

* Wind facility not part of EV 2020. New since 2017 IRP Update.
** EV 2020 in service by December 31, 2020.

Solar

PacifiCorp has a total of 61 solar projects under contract representing 1,759 MW of nameplate capacity. Of these, seven projects totaling 559 MW are new since the 2017 IRP Update.

Table 5.6 – Non-Owned Solar Resources

Power Purchase Agreements / Exchanges	PPA or QF	State	Capacity (MW)
Black Cap	PPA	OR	2
Utah Solar PV Program	PPA	UT	2
Old Mill	PPA	OR	5
Oregon Solar Incentive Projects (OSIP)	PPA	OR	10
Milford *	PPA	UT	99
Hunter *	PPA	UT	100
Sigurd *	PPA	UT	80
Cove Mountain *	PPA	UT	58
Cove Mountain II *	PPA	UT	122
Prineville *	PPA	OR	40
Millican *	PPA	OR	60
Small Solar	QF	UT	0.5
Adams Solar Center	QF	OR	10
Bear Creek Solar Center	QF	OR	10
Beryl Solar	QF	UT	3
Black Cap Solar II	QF	OR	8
Bly Solar Center	QF	OR	9
Buckhorn Solar	QF	UT	3
Cedar Valley Solar	QF	UT	3
Chiloquin Solar	QF	OR	10
Collier Solar	QF	OR	10
Elbe Solar Center	QF	OR	10
Enterprise Solar	QF	UT	80
Escalante Solar I	QF	UT	80
Escalante Solar II	QF	UT	80
Escalante Solar III	QF	UT	80
Ewauna Solar	QF	OR	1
Ewauna Solar 2	QF	OR	3
SunF Solar XVII Project 1-3	QF	UT	9
Granite Mountain - East	QF	UT	80
Granite Mountain - West	QF	UT	50
Granite Peak Solar	QF	UT	3
Greenville Solar	QF	UT	2
Iron Springs	QF	UT	80
Laho Solar	QF	UT	3

Merrill Solar	QF	OR	10
Milford Flat Solar	QF	UT	3
Milford Solar 2	QF	UT	3
Norwest Energy 2 (Neff)	QF	OR	10
Norwest Energy 4 (Bonanza)	QF	OR	6
Norwest Energy 7 (Eagle Point)	QF	OR	10
Norwest Energy 9 Pendleton	QF	OR	6
OR Solar 2, LLC (Agate Bay)	QF	OR	10
OR Solar 3, LLC (Turkey Hill)	QF	OR	10
OR Solar 5, LLC (Merrill)	QF	OR	8
OR Solar 6, LLC (Lakeview)	QF	OR	10
OR Solar 7, LLC (Jacksonville)	QF	OR	10
OR Solar 8, LLC (Dairy)	QF	OR	10
Pavant Solar	QF	UT	50
Pavant Solar II LLC	QF	UT	50
Pavant Solar III LLC	QF	UT	20
Quichapa Solar 1- 3	QF	UT	9
Sage I Solar	QF	WY	20
Sage Il Solar	QF	WY	20
Sage Ill Solar	QF	WY	18
South Milford Solar	QF	UT	3
Sweetwater Solar	QF	WY	80
Three Peaks Solar	QF	UT	80
Tumbleweed Solar	QF	OR	10
Utah Red Hills Renewable Park	QF	UT	80
Woodline Solar	QF	OR	8
TOTAL – Purchased Solar			**1,759**

* New since 2017 IRP Update.

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 has a six-year power purchase agreement with a 3.65 MW QF geothermal project near Lakeview, Oregon, which became operational September 2016.

Biomass/Biogas

PacifiCorp has biomass/biogas agreements with 19 projects totaling approximately 100 MW of nameplate capacity. At least one project is located in each state in PacifiCorp's service territory.

Renewables Net Metering

Installation rates for net metering facilities have been relatively consistent for the last few years in the Pacific Power States. While in the Rocky Mountain Power states the net metering installation rates have declined approximately 40 percent from the peak installed in 2017. Table 5.7 provides a breakdown of net metered capacity and customer counts from data collected on September 30, 2019.

Table 5.7 – Net Metering Customers and Capacities

Fuel	Solar	Wind	Gas[1/]	Hydro	Mixed[2/]
Nameplate (kW)	401,718	873	884	899	1,157
Capacity (percentage of total)	99.06%	0.22%	0.22%	0.22%	0.28%
Number of customers	47,161	198	4	20	58
Customer (percentage of total)	99.41%	0.42%	0.01%	0.04%	0.12%

[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 1,135 MW of hydroelectric generation capacity and purchases the output from 89 MW of other hydroelectric resources.[1] These resources provide operational benefits such as 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 PacifiCorp is able to generate or purchase from hydroelectric plants is dependent upon a number of factors, including the water content of snow pack 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, which lead to load and resource balance capacity values that are different from net facility capacity ratings.

Hydroelectric purchases are categorized into two groups, as shown in Table 5.8, which shows 2019 capacity.

Table 5.8 – Hydroelectric Contracts

Hydroelectric Contracts by Load and Resource Balance Category	Nameplate Capacity (MW)
Hydroelectric	192
Qualifying Facilities—Hydroelectric	88
Total Contracted Hydroelectric Resources	**280**

Table 5.9 provides the capacity for each of PacifiCorp's owned hydroelectric generation facilities in 2019.

[1]PacifiCorp's 2018 10-K shows 1,135 MW of Net Facility Capacity.

Table 5.9 – PacifiCorp Owned Hydroelectric Generation Facilities –Capacities

Plant	State(s)	Capacity (MW)
West		
Big Fork	MT	4
Klamath – Dispatch	CA	56
Klamath – Flat	CA	11
Klamath – Shape	OR	86
Lewis – Dispatch	WA	425
Lewis – Shape[1/]	WA	94
Rogue	OR	31
Small West Hydro[2/]	CA/OR/WA	2
Umpqua – Flat	OR	25
Umpqua – Shape	OR	89
East		
Bear River – Dispatch	ID/UT	60
Bear River – Shape	ID/UT	20
Small East Hydro[3/]	ID/UT/WY	14
TOTAL – Hydroelectric before Contracts		**916**
Plus Hydroelectric Contracts		**280**
TOTAL – Hydroelectric with Contracts		**1,204**

1/ Cowlitz County PUD owns Swift No. 2, and is operated in coordination with the other projects by PacifiCorp
2/ Includes Bend, Fall Creek, and Wallowa Falls
3/ Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Snake Creek, Olmstead, Fountain Green, Veyo, Sand Cove, Viva Naughton, and Gunlock

Hydroelectric Relicensing Impacts on Generation

Table 5.10 lists the estimated impacts to average annual hydro generation from expected Federal Energy Regulatory Commission (FERC) orders and relicensing settlement commitments. PacifiCorp assumes that the Klamath hydroelectric facilities will be decommissioned in accordance with the Klamath Hydroelectric Settlement Agreement in the year 2022 and that other projects currently in relicensing will receive new operating licenses, but that additional operating restrictions will be imposed in new licenses, such as higher bypass flow requirements, that will reduce generation available from these facilities.

Table 5.10 – Estimated Impact of FERC License Renewals and Relicensing Settlement Commitments on Hydroelectric Generation

Years	Incremental Lost Generation (MWh)	Cumulative Lost Generation (MWh)
2019-2020	9,485	11,116
2021-2036	628,000	639,116

Demand-Side Management

For resource planning purposes, PacifiCorp classifies DSM resources into four categories, differentiated by two primary characteristics: reliability and customer choice. 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:

- **Class 1 DSM (Demand Response) —Resources from fully dispatchable or scheduled firm capacity product offerings/programs:** Demand Response programs are those for which capacity savings occur as a result 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.

- **Class 2 DSM (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.

- **Class 3 DSM (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.

- **Class 4 DSM (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. While the company's DSM focus has remained strong over this time, since the 2001 western energy crisis, PacifiCorp's DSM pursuits have 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 5.11 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 5.11 is shown as having zero MW.[2] For a summary of current DSM program offerings in each state, refer to Volume II, Appendix D (Demand-Side Management Resources).

[2] The historical effects of previous Class 2 DSM savings are backed out of the load forecast before the modeling for new Class 2 DSM.

Table 5.11 – Existing DSM Resource Summary

Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2019-2038 Period
1	Residential/small commercial air conditioner load control	122 MW summer peak	Yes.
	Irrigation load management	205 MW summer peak[1/]	Yes.
	Interruptible contracts	177 MW Year-round availability	Yes.
2	PacifiCorp and Energy Trust of Oregon programs	0 MW[2/]	No. Class 2 DSM programs are modeled as resource options in the portfolio development process and included in the preferred portfolio.
3	Time-based pricing	98 MW summer peak	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	55-149 GWh (capacity impacts are unavailable due to lack of information on end use loads being saved	No. Historical savings from customer response to pricing structure is reflected in load forecast.
4	Energy education	Energy and capacity impacts are not available/measured	No. Historical savings from customer participation are reflected in the load forecast.

[1/] Assumes six percent for planning reserves in addition to realized irrigation load curtailment in Idaho and Utah of 170 MW and 20 MW, respectively, with an additional 3 MW from the Oregon pilot through 2020.

[2/] Due to the timing of the 2019 IRP load forecast, there is a small amount (81 MW) of existing Class 2 DSM in Table 5.14 (System Capacity Loads and Resources without Resource Additions).

Private Generation

For the 2019 IRP, PacifiCorp contracted with Navigant Consulting Inc. (Navigant) to update the assessment of private generation (PG) penetration performed for the 2017 IRP with new market and incentive developments. The study provided a forecast of adoption for each private generation resource in each of the six states served by PacifiCorp. Specific technologies studied included solar photovoltaic, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines.

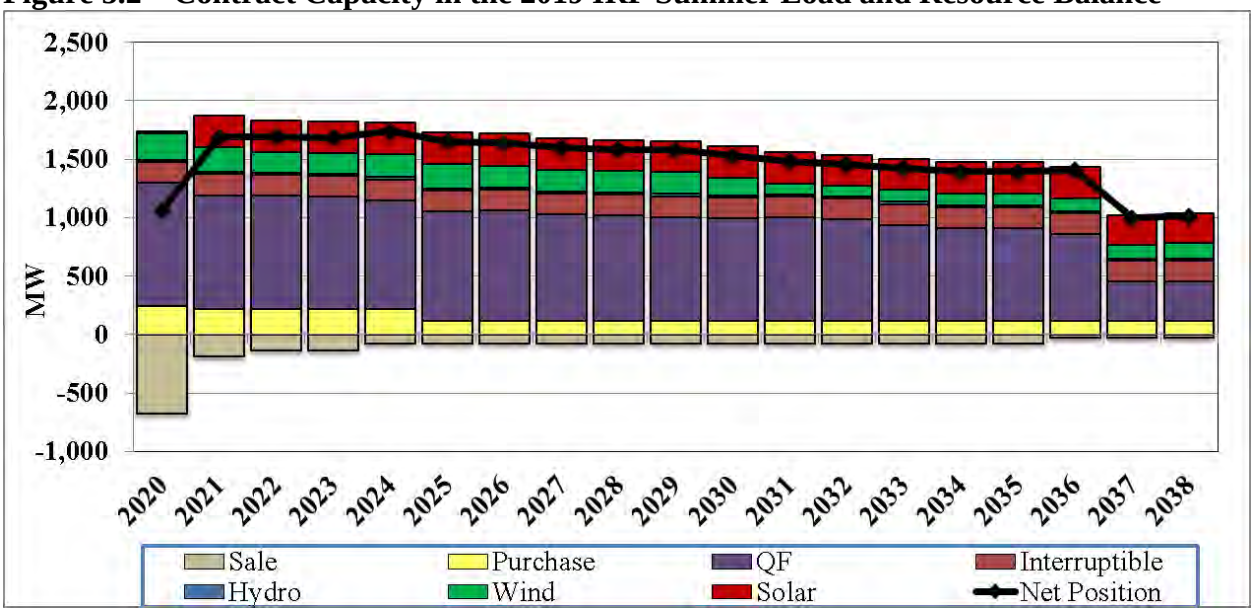
Navigant estimates approximately 1.3 gigawatts (GW) of PG capacity will be installed in PacifiCorp's territory from 2019-2038 in the base case scenario. As shown in Figure 5.1, the low and high scenarios project a cumulative installed capacity of 0.60 GW and 2.3 GW by 2038, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions. As in the 2017 IRP, the Navigant study identifies expected levels of customer-sited private generation, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes.

Figure 5.1 – Private Generation Market Penetration (MW_{AC}), 2019-2038

Power Purchase Contracts

PacifiCorp obtains the remainder of its capacity and energy requirements through long-term firm contracts, short-term firm contracts, and spot market purchases. Figure 5.2 presents the contract capacity in place for 2020 through 2038. As shown, major capacity reductions in wind purchases and QF contracts occur. For planning purposes, PacifiCorp assumes interruptible load contracts are extended through the end of the IRP study period. The renewable wind contracts are shown at their capacity contribution levels.

Figure 5.2 – Contract Capacity in the 2019 IRP Summer Load and Resource Balance



Load and Resource Balance

Capacity and Energy 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. This is done with two views of the system, the capacity balance and energy balance.

The capacity balance compares generating capability at time of system summer peak load hours. It is a key part of the load and resource balance because it helps guide the timing and severity of potential future resource need. The capacity balance is inherently captured in the IRP models for any give scenario. 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 (2019-2028) 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 target PRM and then subtracting the result from existing resources. This view is presented with an account without and with uncommitted FOTs.

The energy balance shows the average monthly on-peak and off-peak surplus or deficit of energy over the first ten years of the planning horizon (2019-2028). The average obligation (load less existing DSM programs, new DSM programs from the preferred portfolio, and projected private generation) is computed and subtracted from the average existing resource availability for each month and time-of-day period. The usefulness of the energy balance is limited because it does not address the cost of the available energy. 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 7 (Modeling and Portfolio Evaluation Approach).

Load and Resource Balance Components

The capacity and energy balances make use of the same load and resource components in their calculations. The main component categories consist of the following: resources, obligation, reserves, position, and available FOTs.

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, existing demand response, sales, and non-owned reserves. Categories in the obligation section include load (net of private generation), interruptible contracts, existing energy efficiency, and new energy efficiency from the preferred portfolio.

Existing Resources

A description of each of the resource categories follows:

Thermal

This category includes all thermal plants that are wholly owned or partially owned by PacifiCorp. The capacity balance counts these plants at their expected availability (after derating for forced outages and maintenance) during summer or winter hours with loss of load events in the final capacity factor methodology analysis.[3] The energy balance also counts them at expected availability, but includes all hours in the year. This includes the existing fleet of coal-fueled units, and six natural-gas-fueled plants. These thermal resources account for roughly two thirds of the firm capacity available in the PacifiCorp system.

Hydroelectric

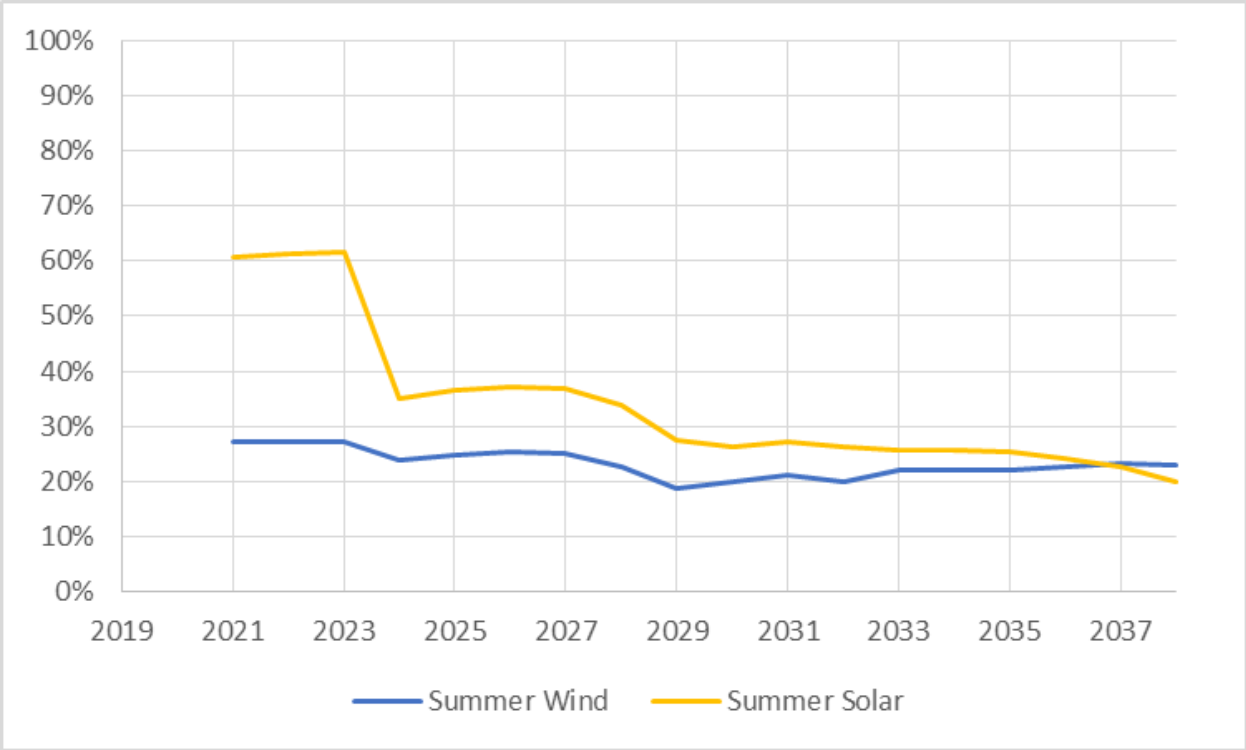
This category includes all hydroelectric generation resources operated in the PacifiCorp system, as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources at their expected availability (after derating for forced outages and maintenance) during summer or winter hours with loss of load events in the final capacity factor methodology analysis. The energy associated with stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. Also accounted for are energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation. Over 90 percent of the hydroelectric capacity is on the west side of the PacifiCorp system.

Renewable

This category is comprised of geothermal and variable (wind and solar) renewable energy capacity. The capacity balance counts the geothermal plant using the same methodology applied to thermal resources. The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. During the 2019 IRP, PacifiCorp identified that capacity contribution values for wind and solar would vary based on the penetration levels of these resources, as well as the composition of the rest of a portfolio. To account for these effects, PacifiCorp performed a reliability analysis on every portfolio that was developed to ensure that the combination of resources achieved a targeted level of reliability. For the purpose of reporting the capacity contribution of wind and solar resources in the load and resource balance, PacifiCorp first calculated the contribution of all other resources in the portfolio, using the methodologies described in this section. The remaining capacity in the load and resource balance, up to PacifiCorp's thirteen percent planning reserve margin, is attributable to wind and solar. This remaining capacity was allocated to each wind and solar resource based on the wind and solar penetration analysis and the final capacity factor methodology analysis, as discussed in Volume II, Appendix N (Capacity Contribution Study). The resulting capacity contribution values for wind and solar for the purpose of the load and resource balance are shown in Figure 5.3 (summer) and Figure 5.4 (winter) below.

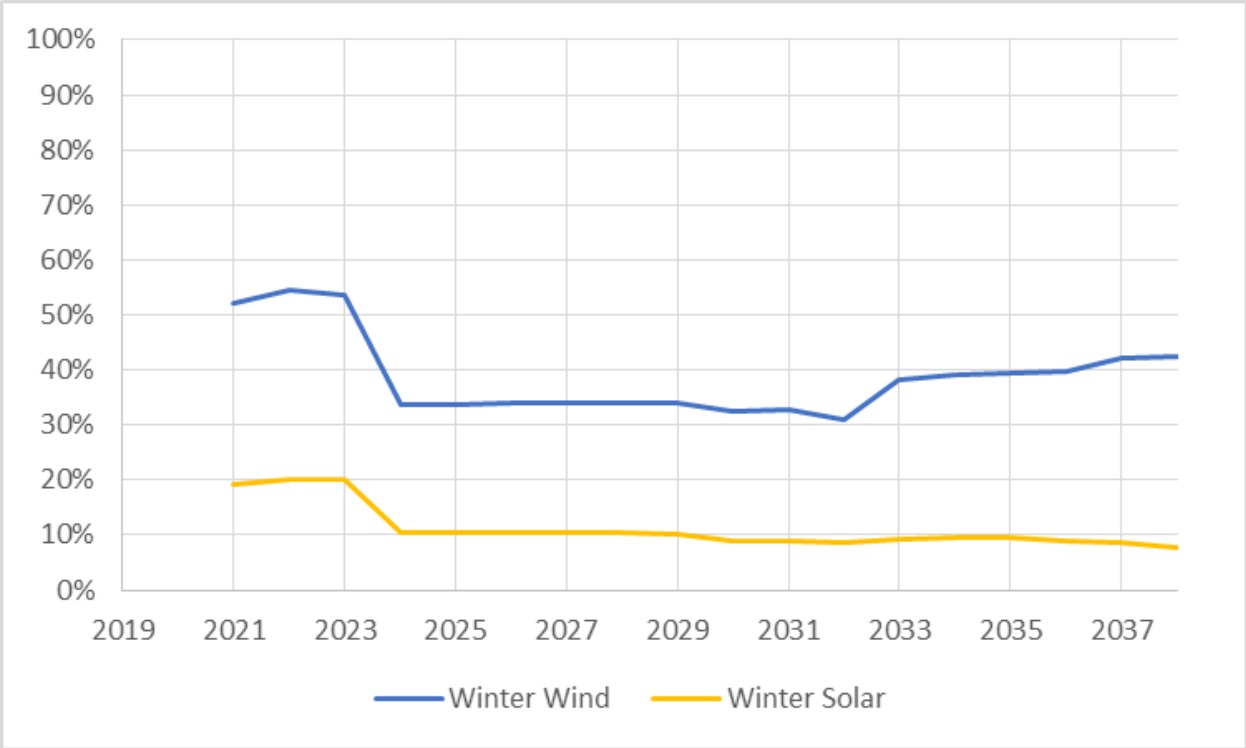
[3] Please refer to Volume II, Appendix N (Capacity Contribution Study)

Figure 5.3 – Summer Peak Capacity Contribution Values for Wind and Solar



Note: Marginal benefits are lower than shown; refer to Volume II, Appendix N (Capacity Contribution Study).

Figure 5.4 – Winter Peak Capacity Contribution Values for Wind and Solar



Note: Marginal benefits are lower than shown; refer to Volume II, Appendix N (Capacity Contribution Study).

Purchase
This includes all major purchase contracts for firm capacity and energy in the PacifiCorp system.[4] The capacity balance counts these by the maximum contract availability at time of system summer peak. The energy balance counts contracts at optimal economic model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

Qualifying Facilities
All QFs that provide capacity and energy are included in this category. Wind and solar QFs are handled in the same manner as non-QF renewable resources, as described above. Other QFs are handled in the same manner as other power purchases, the capacity balance counts them at maximum system summer peak availability and the energy balance counts them at optimal economic model dispatch.

Demand Response (Class 1 DSM)
Existing demand response program capacity is categorized as an increase to resource capacity. This is in line with the treatment of DSM capacity in the latest version of the System Optimizer model that PacifiCorp uses to select resources.

Sales
This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system summer peak and the energy balance counts them by expected model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view.

Non-owned Reserves
Non-owned reserve capacity is categorized as a decrease to resource capacity to represent the capacity required to provide reserves for load and generation that are in PacifiCorp's balancing authority area (BAA) but not used to serve the company's retail load. There are a number of wholesale customers that operate in the PacifiCorp control areas that purchase operating reserves. The annual reserve obligation is about three MW in the west BAA and 38 MW in the east BAA. The non-owned reserves do not contribute to the energy obligation because the requirement is for capacity only.

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, 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 2019 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. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer peak. The energy balance

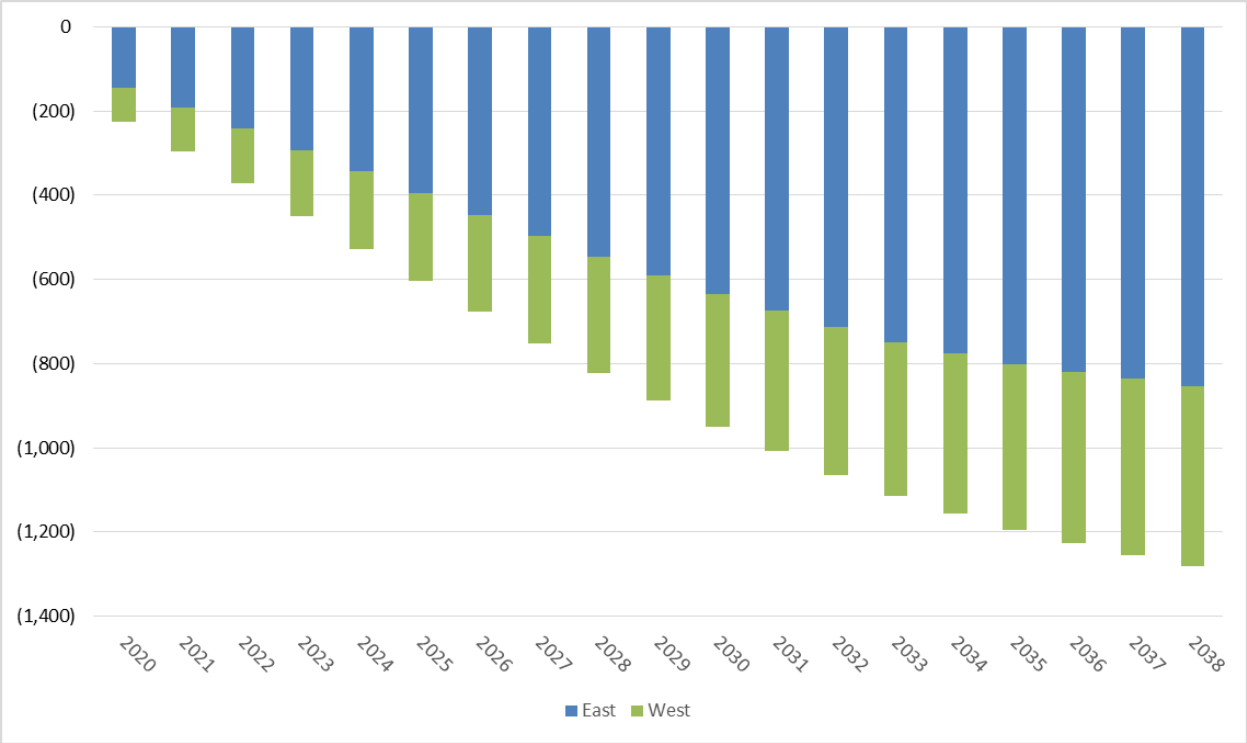
[4] PacifiCorp has curtailment contracts for approximately 172 MW on peak capacity that are treated as firm purchases. PacifiCorp has the right to curtail the customer's load as needed for economic purposes. The customer in turn may or may not pay market-based rates for energy used during a curtailment period.

counts the load on monthly basis by on-peak and off-peak hours. The net load is simply referred to as load in the context of load and resources balances and portfolio selection and evaluation.

Energy Efficiency (Class 2 DSM)

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 2018 Energy Efficiency that is not incorporated in the forecast. The 2018 energy efficiency forecast (81 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 selected energy efficiency from the 2019 IRP preferred portfolio. Figure 5.5 shows the energy efficiency for the east and west control areas in the 2019 IRP preferred portfolio.

Figure 5.5 – Energy Efficiency Peak Contribution in Summer Capacity Load and Resource Balance (reduction to load)



Interruptible Contracts

PacifiCorp has interruptible contracts for approximately 177 MW of load interruption capability beginning in 2019. These contracts allow the use of 177 MW of capacity for meeting reserve requirements. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus full planning reserves are not held for the load that may be curtailed. As with demand response, this resource is categorized as a decrease to the peak load.

Planning Reserves

Planning reserves represent an incremental planning 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. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

Capacity Balance Determination

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 + Firm Purchases + Qualifying Facilities + Existing Demand Response – Firm Sales – Non-owned Reserves

The peak load, interruptible contracts, 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 – Interruptible Contracts – New and Existing Energy Efficiency

The amount of reserves to be added to the obligation is then calculated. This is accomplished by the net system obligation calculated above multiplied by the 13 percent target PRM adopted for the 2019 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 FOTs, as shown in the following formula:

> **Capacity Position** = (Existing Resources + Available FOTs) – (Obligation + Reserves)

Capacity Balance Results

Table 5.12 and Table 5.13 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 5.12 -- Summer Peak – System Capacity Loads and Resources without Resource Additions[1/]

Calendar Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
East										
Thermal	5,963	5,634	5,634	5,634	5,634	5,634	5,217	5,140	4,481	4,481
Hydroelectric	74	74	74	74	74	74	74	74	74	74
Renewable	406	843	859	866	876	906	898	891	827	718
Purchases	242	215	215	215	215	115	115	115	115	115
Qualifying Facilities	891	666	665	665	617	619	621	620	610	590
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sales	(655)	(175)	(175)	(175)	(148)	(148)	(66)	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**7,210**	**7,545**	**7,560**	**7,567**	**7,555**	**7,488**	**7,148**	**7,128**	**6,395**	**6,267**
Load	7,039	7,108	7,185	7,276	7,405	7,442	7,460	7,523	7,604	7,678
Private Generation	(125)	(166)	(173)	(176)	(202)	(188)	(195)	(204)	(218)	(233)
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(144)	(192)	(241)	(293)	(345)	(396)	(446)	(497)	(546)	(591)
East obligation	**6,592**	**6,572**	**6,593**	**6,629**	**6,681**	**6,682**	**6,641**	**6,644**	**6,663**	**6,677**
Planning Reserves (13%)	880	877	880	885	892	892	886	887	889	891
East Obligation + Reserves	**7,471**	**7,450**	**7,474**	**7,514**	**7,573**	**7,574**	**7,528**	**7,531**	**7,552**	**7,568**
East Position	**0**	**95**	**86**	**53**	**(17)**	**(85)**	**(380)**	**(403)**	**(1,156)**	**(1,300)**
Available Front Office Transactions	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**
West										
Thermal	2,048	2,048	2,048	2,048	1,736	1,736	1,736	1,736	1,598	1,265
Hydroelectric	570	570	570	570	570	570	570	570	570	570
Renewable	383	379	287	289	289	298	302	300	273	240
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	390	292	285	278	278	279	278	246	243	231
Class 1 DSM	3	0	0	0	0	0	0	0	0	0
Sales	(165)	(161)	(110)	(110)	(80)	(80)	(80)	(80)	(80)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,227**	**3,126**	**3,078**	**3,074**	**2,792**	**2,802**	**2,805**	**2,771**	**2,604**	**2,227**
Load	3,387	3,441	3,486	3,513	3,529	3,570	3,597	3,626	3,657	3,684
Private Generation	(21)	(26)	(29)	(32)	(45)	(39)	(44)	(51)	(58)	(66)
Interruptible	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	(81)	(106)	(131)	(157)	(183)	(208)	(232)	(255)	(276)	(296)
West obligation	**3,285**	**3,310**	**3,325**	**3,324**	**3,301**	**3,323**	**3,321**	**3,321**	**3,323**	**3,321**
Planning Reserves (13%)	427	430	432	432	429	432	432	432	432	432
West Obligation + Reserves	**3,712**	**3,740**	**3,757**	**3,756**	**3,730**	**3,755**	**3,753**	**3,753**	**3,755**	**3,753**
West Position	**(484)**	**(614)**	**(679)**	**(683)**	**(938)**	**(953)**	**(948)**	**(982)**	**(1,151)**	**(1,527)**
Available Front Office Transactions	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**
System										
Total Resources	10,437	10,671	10,638	10,641	10,347	10,290	9,953	9,899	8,999	8,494
Obligation	9,876	9,882	9,918	9,953	9,982	10,005	9,962	9,966	9,985	9,998
Reserves	1,307	1,308	1,312	1,317	1,321	1,324	1,318	1,319	1,321	1,323
Obligation + Reserves	11,183	11,190	11,231	11,270	11,303	11,328	11,281	11,284	11,306	11,321
System Position	(746)	(519)	(592)	(630)	(956)	(1,038)	(1,328)	(1,385)	(2,307)	(2,827)
Available Front Office Transactions	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**
Uncommitted FOTs to meet remaining Need	746	519	592	630	956	1,038	1,328	1,385	1,468	1,468
Net Surplus (Deficit)	0	0	0	0	0	0	0	0	(839)	(1,359)

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

Table 5.12 (cont.) – Summer Peak System Capacity Loads and Resources without Resource Additions[1/]

Calendar Year	2030	2031	2032	2033	2034	2035	2036	2037	2038
East									
Thermal	4,242	4,169	4,169	3,838	3,838	3,838	3,838	2,984	2,984
Hydroelectric	74	74	74	74	74	74	74	74	74
Renewable	723	706	675	725	726	724	737	740	697
Purchases	115	115	115	115	115	115	115	115	115
Qualifying Facilities	595	599	587	555	536	536	503	125	120
Class 1 DSM	323	323	323	323	323	323	323	323	323
Sales	0	0	0	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**6,036**	**5,952**	**5,908**	**5,596**	**5,577**	**5,575**	**5,556**	**4,326**	**4,279**
Load	7,760	7,830	7,923	8,007	7,935	8,019	8,104	8,196	8,280
Private Generation	(249)	(264)	(281)	(316)	(227)	(261)	(295)	(330)	(374)
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(634)	(674)	(713)	(750)	(777)	(801)	(820)	(836)	(854)
East obligation	**6,700**	**6,713**	**6,751**	**6,763**	**6,754**	**6,780**	**6,811**	**6,853**	**6,876**
Planning Reserves (13%)	894	896	901	902	901	904	909	914	917
East Obligation + Reserves	**7,594**	**7,609**	**7,652**	**7,665**	**7,655**	**7,684**	**7,720**	**7,767**	**7,793**
East Position	**(1,557)**	**(1,657)**	**(1,744)**	**(2,070)**	**(2,078)**	**(2,109)**	**(2,164)**	**(3,440)**	**(3,514)**
Available Front Office Transactions	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**
West									
Thermal	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,053	411
Hydroelectric	570	570	570	570	570	570	570	570	570
Renewable	249	259	248	266	266	265	270	275	270
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	228	229	222	223	223	223	217	201	201
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(78)	(78)	(78)	(78)	(78)	(78)	(24)	(24)	(24)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**2,233**	**2,244**	**2,226**	**2,245**	**2,245**	**2,244**	**2,297**	**2,073**	**1,427**
Load	3,709	3,745	3,773	3,803	3,788	3,814	3,842	3,881	3,912
Private Generation	(79)	(102)	(134)	(173)	(155)	(191)	(226)	(260)	(300)
Interruptible	0	0	0	0	0	0	0	0	0
Energy Efficiency	(315)	(333)	(350)	(365)	(379)	(393)	(406)	(417)	(428)
West obligation	**3,314**	**3,310**	**3,289**	**3,265**	**3,254**	**3,231**	**3,210**	**3,204**	**3,184**
Planning Reserves (13%)	431	430	428	424	423	420	417	417	414
West Obligation + Reserves	**3,745**	**3,740**	**3,717**	**3,689**	**3,677**	**3,651**	**3,627**	**3,621**	**3,598**
West Position	**(1,512)**	**(1,497)**	**(1,491)**	**(1,444)**	**(1,431)**	**(1,406)**	**(1,330)**	**(1,548)**	**(2,171)**
Available Front Office Transactions	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**
System									
Total Resources	8,270	8,196	8,134	7,841	7,822	7,819	7,853	6,399	5,706
Obligation	10,014	10,024	10,040	10,028	10,008	10,011	10,021	10,057	10,060
Reserves	1,325	1,326	1,328	1,327	1,324	1,324	1,326	1,330	1,331
Obligation + Reserves	11,339	11,350	11,368	11,355	11,332	11,335	11,347	11,387	11,391
System Position	(3,070)	(3,154)	(3,234)	(3,514)	(3,510)	(3,516)	(3,495)	(4,988)	(5,685)
Available Front Office Transactions	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**
Uncommitted FOTs to meet remaining Need	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468
Net Surplus (Deficit)	(1,602)	(1,686)	(1,766)	(2,046)	(2,042)	(2,048)	(2,027)	(3,520)	(4,217)

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

Table 5.13 – Winter Peak System Capacity Loads and Resources without Resource Additions[1/]

Calendar Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
East										
Thermal	6,020	5,692	5,692	5,692	5,692	5,692	5,275	5,199	4,545	4,545
Hydroelectric	54	54	54	54	54	54	54	54	54	54
Renewable	992	1,536	1,594	1,579	1,020	1,020	1,010	1,009	1,010	1,001
Purchases	727	228	228	228	115	115	115	115	115	115
Qualifying Facilities	672	460	465	413	335	333	334	334	333	326
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	(173)	(173)	(173)	(173)	(148)	(148)	(66)	(52)	0	(77)
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**8,258**	**7,762**	**7,825**	**7,758**	**7,032**	**7,031**	**6,687**	**6,625**	**6,022**	**5,931**
Load	5,629	5,680	5,743	5,807	5,855	5,921	5,847	5,889	5,939	5,993
Private Generation	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(5)	(5)
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(107)	(147)	(189)	(233)	(277)	(321)	(365)	(409)	(452)	(492)
East obligation	**5,344**	**5,355**	**5,376**	**5,396**	**5,399**	**5,420**	**5,301**	**5,298**	**5,305**	**5,319**
Planning Reserves (13%)	718	719	722	724	725	728	712	712	713	714
East Obligation + Reserves	**6,062**	**6,074**	**6,098**	**6,120**	**6,123**	**6,148**	**6,014**	**6,010**	**6,018**	**6,033**
East Position	**0**	**1,688**	**1,727**	**1,638**	**909**	**883**	**673**	**615**	**4**	**(102)**
Available Front Office Transactions	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**
West										
Thermal	2,040	2,040	2,040	2,040	1,728	1,728	1,728	1,728	1,590	1,258
Hydroelectric	670	670	670	670	670	670	670	670	670	670
Renewable	672	351	232	230	137	137	138	138	137	136
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	142	102	93	88	75	75	72	45	45	33
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	(154)	(154)	(113)	(113)	(81)	(81)	(81)	(81)	(81)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,369**	**3,008**	**2,921**	**2,913**	**2,527**	**2,527**	**2,525**	**2,499**	**2,360**	**2,018**
Load	3,416	3,458	3,499	3,529	3,550	3,576	3,605	3,640	3,672	3,706
Private Generation	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)
Interruptible	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	(89)	(118)	(150)	(181)	(214)	(244)	(274)	(303)	(331)	(356)
West obligation	**3,327**	**3,340**	**3,350**	**3,347**	**3,335**	**3,331**	**3,329**	**3,335**	**3,340**	**3,347**
Planning Reserves (13%)	432	434	435	435	434	433	433	434	434	435
West Obligation + Reserves	**3,759**	**3,774**	**3,785**	**3,782**	**3,769**	**3,764**	**3,762**	**3,769**	**3,774**	**3,783**
West Position	**(390)**	**(766)**	**(864)**	**(869)**	**(1,242)**	**(1,237)**	**(1,237)**	**(1,270)**	**(1,414)**	**(1,765)**
Available Front Office Transactions	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**
System										
Total Resources	11,627	10,770	10,746	10,671	9,560	9,558	9,212	9,124	8,382	7,949
Obligation	8,671	8,695	8,725	8,743	8,734	8,751	8,631	8,634	8,645	8,666
Reserves	1,150	1,153	1,157	1,160	1,158	1,161	1,145	1,145	1,147	1,150
Obligation + Reserves	9,821	9,848	9,883	9,902	9,892	9,912	9,776	9,779	9,792	9,815
System Position	1,806	922	864	769	(333)	(354)	(564)	(655)	(1,410)	(1,867)
Available Front Office Transactions	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**
Uncommitted FOT's to meet remaining Need	0	0	0	0	333	354	564	655	1,410	1,468
Net Surplus (Deficit)	1,806	922	864	769	0	0	0	0	0	(399)

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

Table 5.13 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions[1/]

Calendar Year	2030	2031	2032	2033	2034	2035	2036	2037	2038
East									
Thermal	4,311	4,239	4,239	3,908	3,908	3,908	3,908	3,054	3,054
Hydroelectric	54	54	54	54	54	54	54	54	54
Renewable	942	891	846	1,015	1,036	1,039	1,045	1,099	1,073
Purchases	115	115	115	115	115	115	115	115	115
Qualifying Facilities	325	326	310	284	251	251	222	26	26
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(77)	0	0	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**5,636**	**5,590**	**5,529**	**5,341**	**5,330**	**5,333**	**5,309**	**4,313**	**4,287**
Load	6,023	6,074	6,113	6,180	6,232	6,287	6,320	6,380	6,431
Private Generation	(6)	(7)	(8)	(9)	(10)	(12)	(14)	(15)	(17)
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(530)	(565)	(600)	(632)	(656)	(678)	(696)	(711)	(726)
East obligation	**5,310**	**5,324**	**5,328**	**5,362**	**5,389**	**5,420**	**5,434**	**5,477**	**5,510**
Planning Reserves (13%)	713	715	716	720	724	728	729	735	739
East Obligation + Reserves	**6,023**	**6,040**	**6,044**	**6,083**	**6,113**	**6,147**	**6,163**	**6,212**	**6,249**
East Position	**(387)**	**(450)**	**(515)**	**(741)**	**(783)**	**(815)**	**(854)**	**(1,899)**	**(1,962)**
Available Front Office Transactions	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**
West									
Thermal	1,258	1,258	1,258	1,258	1,258	1,258	1,258	1,034	392
Hydroelectric	670	670	670	670	670	670	670	670	670
Renewable	135	135	128	155	159	159	160	169	170
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	33	33	27	29	29	29	25	24	24
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**2,016**	**2,017**	**2,003**	**2,032**	**2,036**	**2,036**	**2,034**	**1,818**	**1,177**
Load	3,727	3,751	3,782	3,816	3,849	3,880	3,902	3,933	3,967
Private Generation	(2)	(3)	(3)	(4)	(4)	(5)	(7)	(8)	(11)
Interruptible	0	0	0	0	0	0	0	0	0
Energy Efficiency	(380)	(403)	(424)	(443)	(461)	(479)	(495)	(510)	(525)
West obligation	**3,345**	**3,346**	**3,355**	**3,369**	**3,384**	**3,396**	**3,400**	**3,415**	**3,431**
Planning Reserves (13%)	435	435	436	438	440	441	442	444	446
West Obligation + Reserves	**3,780**	**3,781**	**3,791**	**3,808**	**3,824**	**3,838**	**3,842**	**3,859**	**3,877**
West Position	**(1,763)**	**(1,764)**	**(1,787)**	**(1,775)**	**(1,788)**	**(1,801)**	**(1,808)**	**(2,041)**	**(2,700)**
Available Front Office Transactions	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**
System									
Total Resources	7,653	7,607	7,532	7,373	7,365	7,369	7,343	6,131	5,464
Obligation	8,655	8,670	8,683	8,732	8,773	8,816	8,834	8,892	8,941
Reserves	1,148	1,150	1,152	1,158	1,163	1,169	1,171	1,179	1,185
Obligation + Reserves	9,803	9,820	9,835	9,890	9,936	9,985	10,005	10,071	10,126
System Position	(2,150)	(2,214)	(2,302)	(2,517)	(2,571)	(2,616)	(2,662)	(3,940)	(4,662)
Available Front Office Transactions	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**
Uncommitted FOTs to meet remaining Need	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468
Net Surplus (Deficit)	(682)	(746)	(835)	(1,049)	(1,103)	(1,148)	(1,194)	(2,472)	(3,194)

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

Figure 5.6 through Figure 5.9 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 FOTs, which can be used to meet capacity needs. The market availability assumptions used for portfolio modeling are discussed further in Chapter 6 (Resource Options) and Volume II, Appendix J (Western Resource Adequacy Evaluation).

Figure 5.6 – Summer System Capacity Position Trend

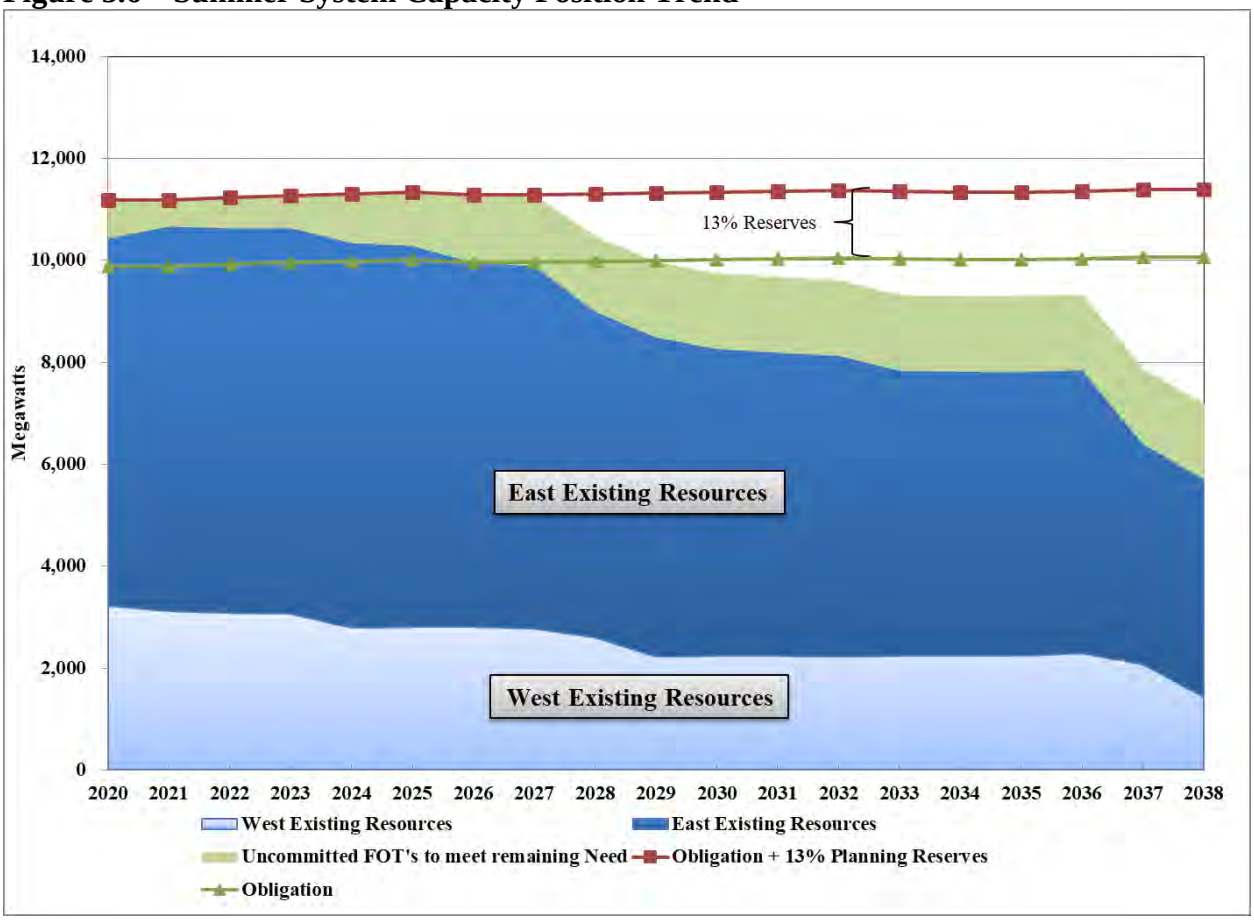


Figure 5.7 – Winter System Capacity Position Trend

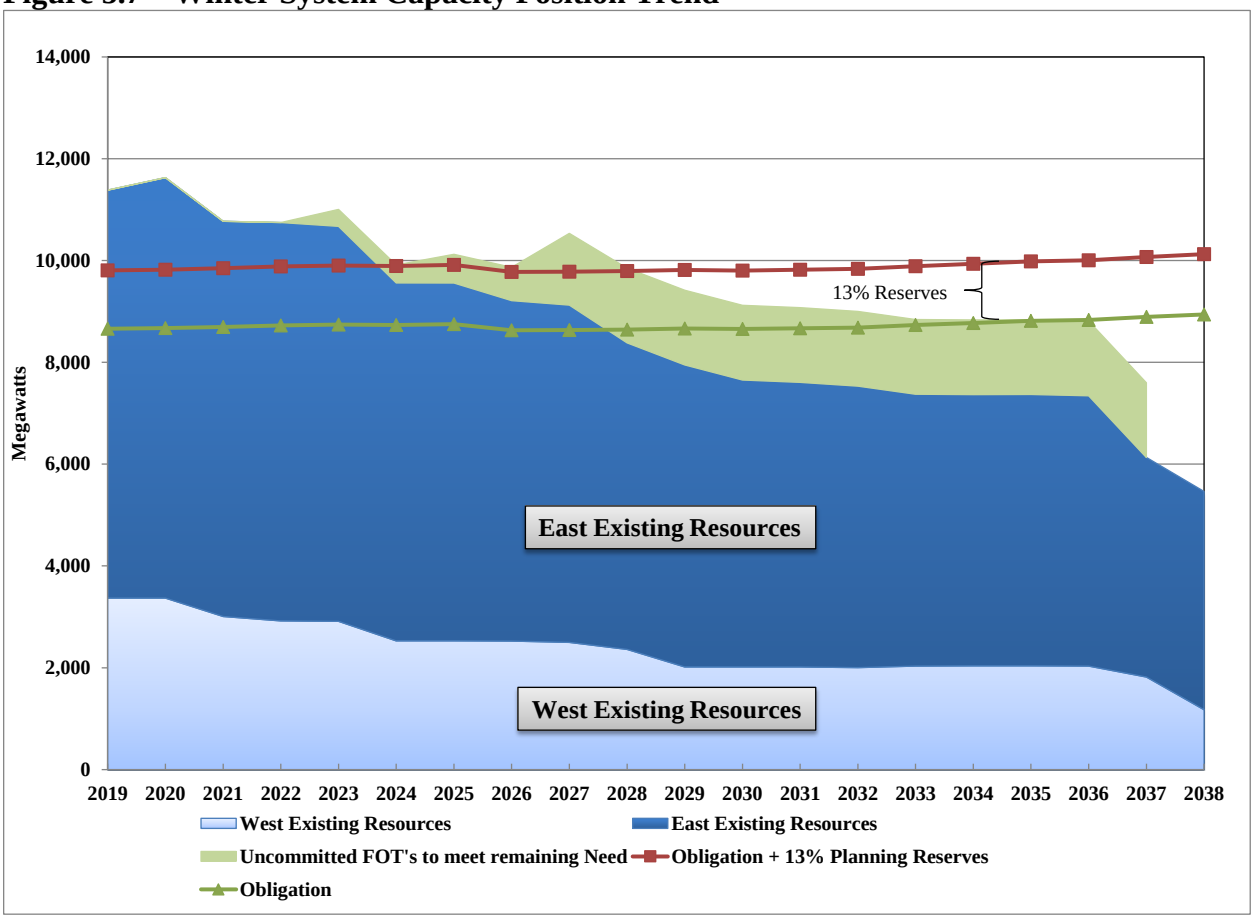


Figure 5.8 – East Summer Capacity Position Trend

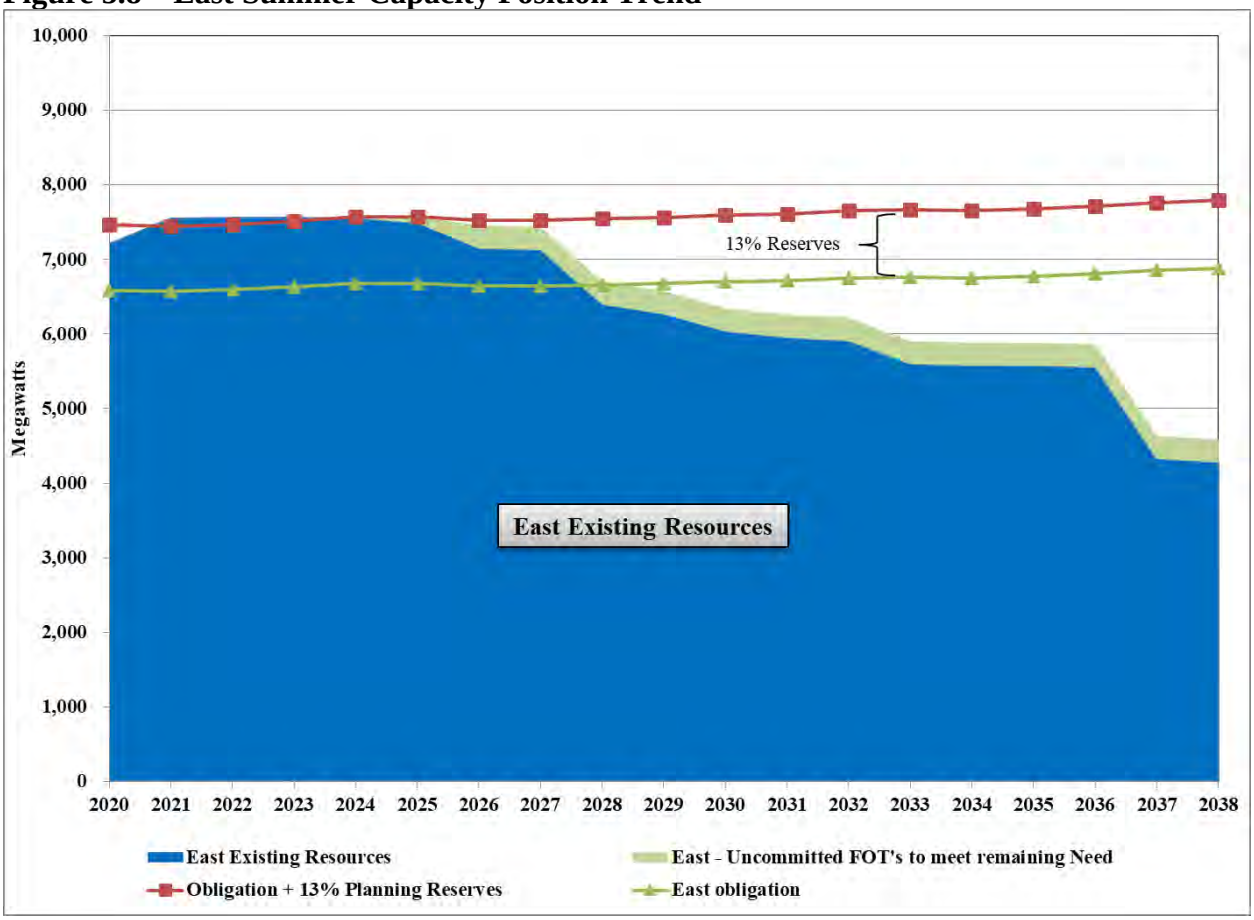
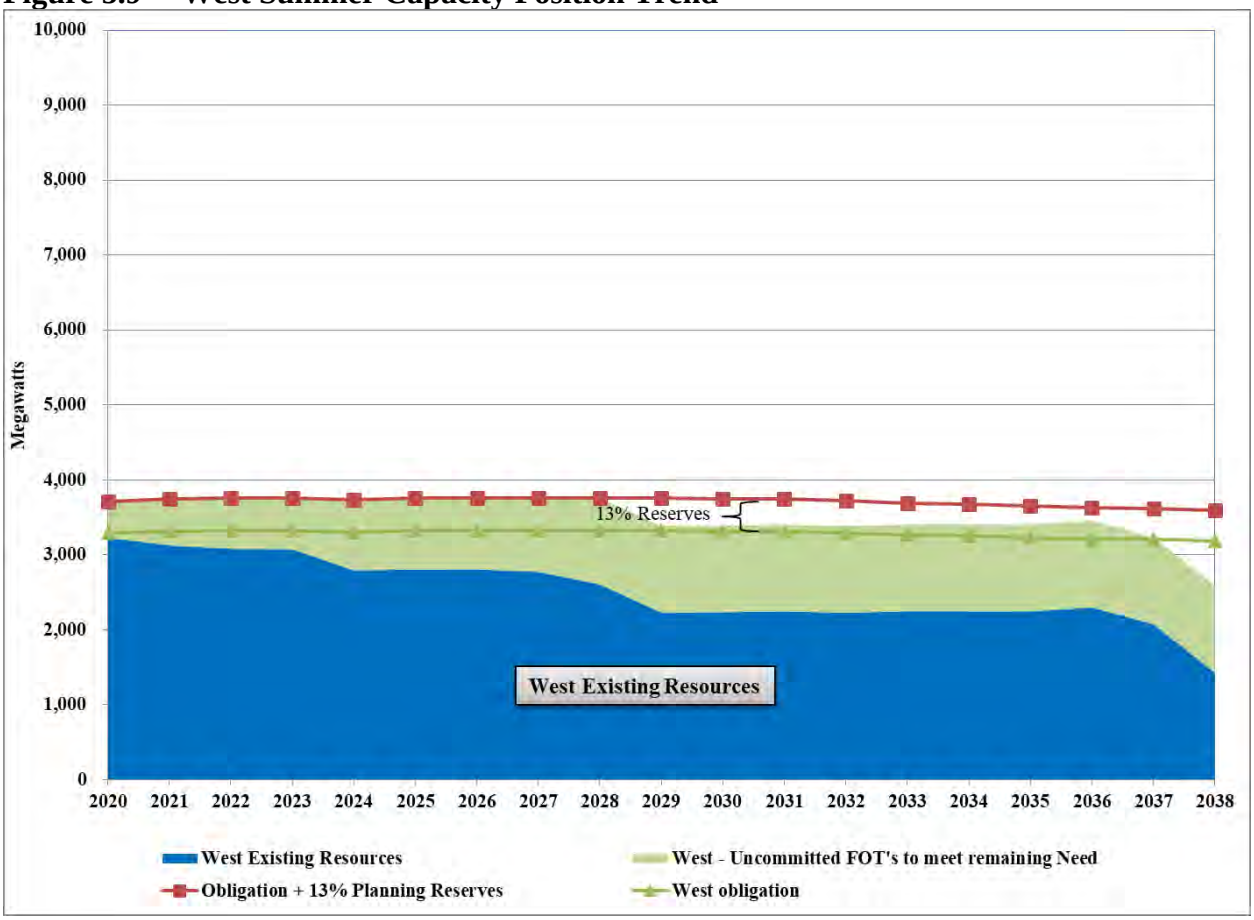


Figure 5.9 – West Summer Capacity Position Trend



Energy Balance Determination

Methodology

The energy balance shows the monthly on-peak and off-peak surplus (deficit) of energy. The on-peak hours are weekdays and Saturdays from hour-ending 7:00 am to 10:00 pm; off-peak hours are all other hours. This is calculated using the formulas that follow. Please refer to the section on load and resource balance components for details on how energy for each component is counted.

> **Existing Resources** = Thermal + Hydro + Existing Class 1 DSM + Renewable + Firm Purchases + QF + Interruptible Contracts – Sales

The average obligation is computed using the following formula:

> **Obligation** = Load + Firm Sales

The energy position by month and time block is then computed as follows:

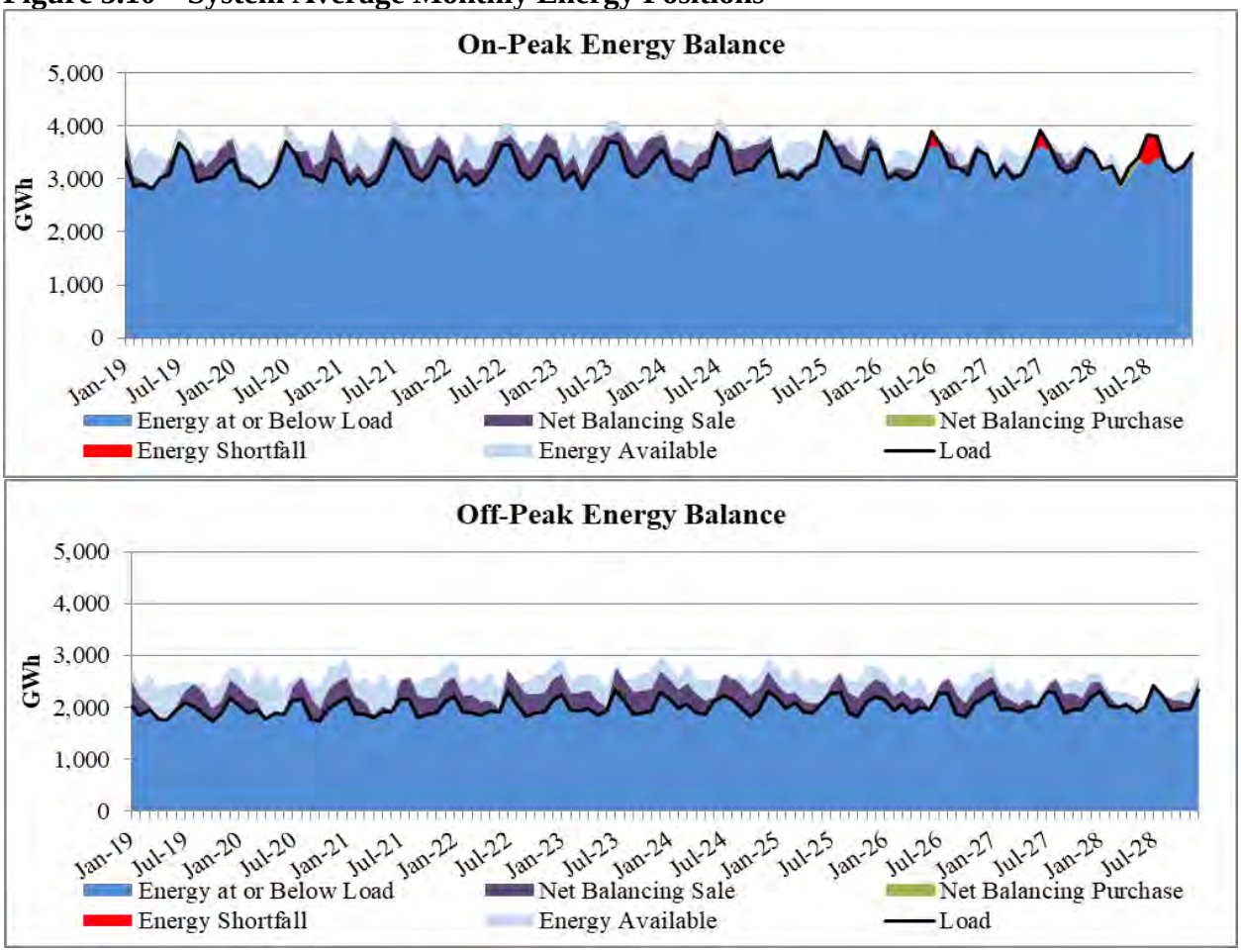
> **Energy Position** = Existing Resources – Obligation – Operating Reserve Requirements

Energy Balance Results

The capacity position shows how existing resources and loads, accounting for coal unit retirements and incremental energy efficiency savings from the preferred portfolio, balance during the coincident peak summer and winter. Outside of these peak periods, PacifiCorp economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when variable costs of the system resources are less than the prevailing market price for power, PacifiCorp can dispatch resources that in aggregate exceed then-current load obligations facilitating off system sales that reduce customer costs. Conversely, at times when system resource costs fall below prevailing market prices, system balancing market purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how PacifiCorp manages net power costs.

Figure 5.10 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given the assumptions about resource availability and wholesale power and natural gas prices. At times, resources are economically dispatched above load levels facilitating net system balancing sales. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 5.10 also shows how much energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and indicate short energy positions without the addition of incremental resources to the portfolio.

Figure 5.10 – System Average Monthly Energy Positions



CHAPTER 6 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp developed resource attributes and costs for expansion resources that reflect updated information from project experience, industry vendors, public meeting comments and studies.
- Resource costs have been generally stable since the previous integrated resource plan (IRP) and cost increases have been modest to declining. The cost of solar photovoltaic modules and balance of plant equipment decreased in 2018, continuing the downward cost trend of the past several years. Likewise, costs of wind turbines and batteries, and associated balance of plant costs, have shown a decline.
- Geothermal power purchase agreements (PPAs) are included as supply-side options in this IRP and updated to reflect current conditions.
- The combustion turbine types, configurations, and siting locations are identified in the supply-side resource options table. Performance and costs have been updated.
- Energy storage systems continue to be of interest to PacifiCorp, its stakeholders, and the industry at large. Options for advanced large batteries (15 megawatts (MW) and larger), renewable (wind and solar) plus storage, pumped hydro and compressed air energy storage are included in this IRP.
- For this IRP, PacifiCorp developed the capability for the System Optimizer (SO) model to endogenously model transmission upgrades.
- A 2018 Long Term Generation Resource Assessment study that was conducted by Navigant Consulting, Inc. served as the basis for updated resource characterizations covering private generation. The demand-side resource information was converted into supply curves grouped into cost bundles by measure or product type and competed against other resource alternatives in IRP modeling.
- 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 reflect 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 2017 IRP. New wind resources were given

particular attention after the 2017 IRP selected a combination of wind and transmission resources for investment that would provide value for PacifiCorp's customers. Energy storage options of at least one MW continue to be of interest to PacifiCorp, its stakeholders, and the industry at large. PacifiCorp analyzed options for large pumped hydro projects and utility scale batteries. In response to stakeholder requests and utility industry trends, PacifiCorp studied multiple different battery energy storage configurations and combined battery configurations collocated with wind and solar projects. Solar resource options examined 200 MW single axis tracking facilities to reflect the industry trend of larger utility-size photovoltaic (PV) systems. A variety of gas-fueled generating resources were identified after consultation with major suppliers, large engineering-consulting firm and stakeholders. The combustion turbine types and configurations identified for consideration in the 2019 IRP are the same as those used in the 2017 IRP. Combustion turbine types and configurations remained the same 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 flat to slightly decreasing cost trend. New coal-fueled and nuclear resources received minimal focus during this cycle due to ongoing environmental, economic, permitting and sociopolitical obstacles.

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 2017 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 (2018) third-party, cost-and-performance estimates;
- Publicly available cost and performance estimates;
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes;
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options; and
- Recent requests for proposals (RFP) and requests for information (RFI).

Recent third-party engineering information from original equipment manufacturers were used to develop capital, operating and maintenance costs, performance and operating characteristics and planned outage cycle estimates. Engineering-consultants or government agencies have access to this data based on prior research studies, academia, actual installations, and direct information exchanges with original equipment manufacturers. Examples of this type of effort include the 2018 Black & Veatch estimates prepared for simple cycle and combined cycle options. For this IRP cycle, the energy storage effort was performed by Burns & McDonnell and covers solar and wind resources. The Burns & McDonnell study builds upon prior energy storage studies, updates cost and technical information, and adds combined renewables plus energy storage resource options.

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 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.

Recent RFIs and RFPs also provide a useful source of cost-and-performance data. In these cases, original equipment manufacturers provided technology specific information. Examples of RFIs informing the SSR include obtaining updated equipment pricing for wind turbine equipment from original equipment suppliers and reviews of capital costs prepared by engineering firms by engineer-procure-construct firms.

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 the relatively small number of facilities that have been built, especially for new and emerging technologies, as well as prolonged economic uncertainty. Despite this uncertainty, the cost profile between the 2017 IRP and the 2019 IRP has not changed significantly. For example, Figure 6.1 shows the trend in North American carbon steel sheet prices over the period from October 2015 through June 2018. The 2017 IRP included the historic carbon steel pricing shown in Figure 6.2. These figures illustrate near-term changes in capital costs of generation resources.

Figure 6.1 – World Carbon Steel Pricing by Type

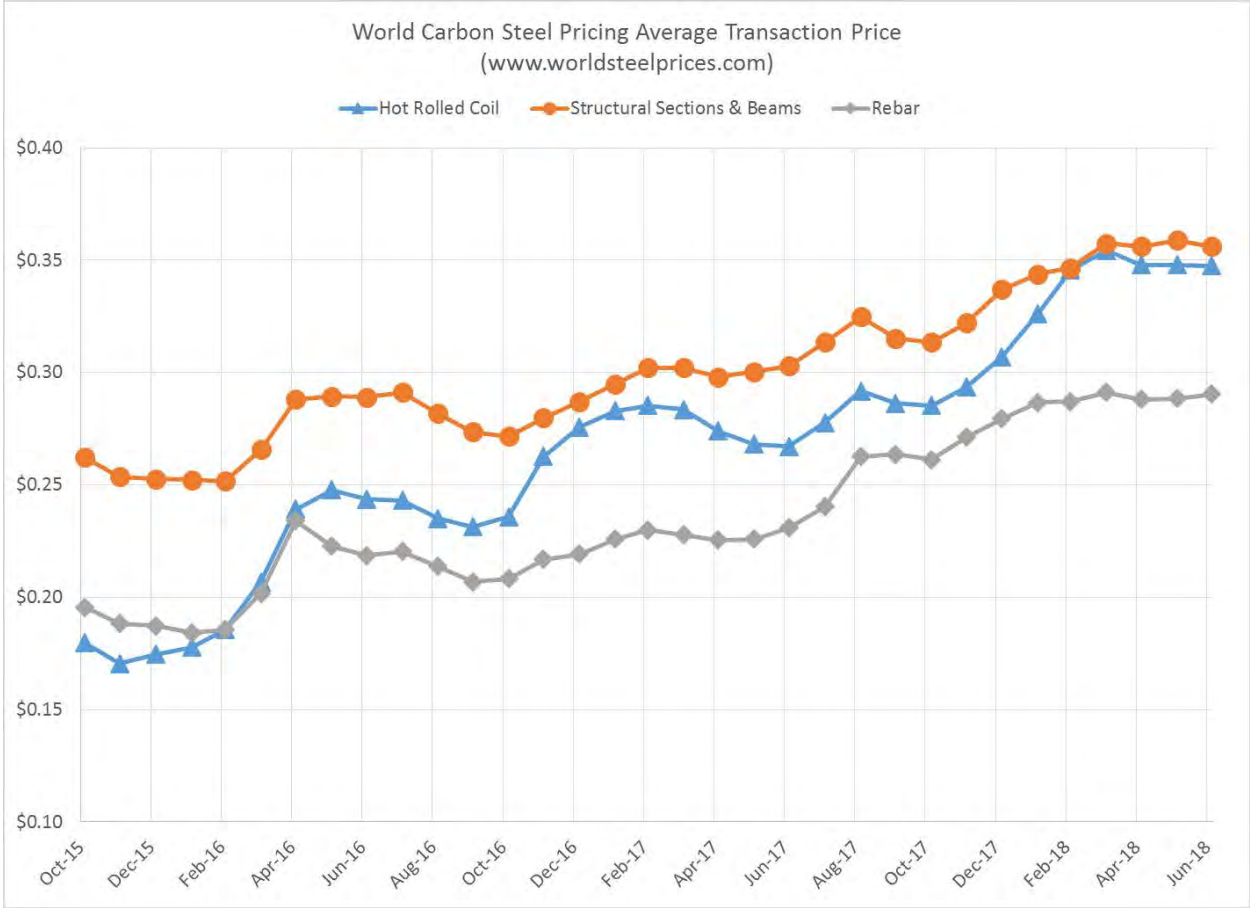
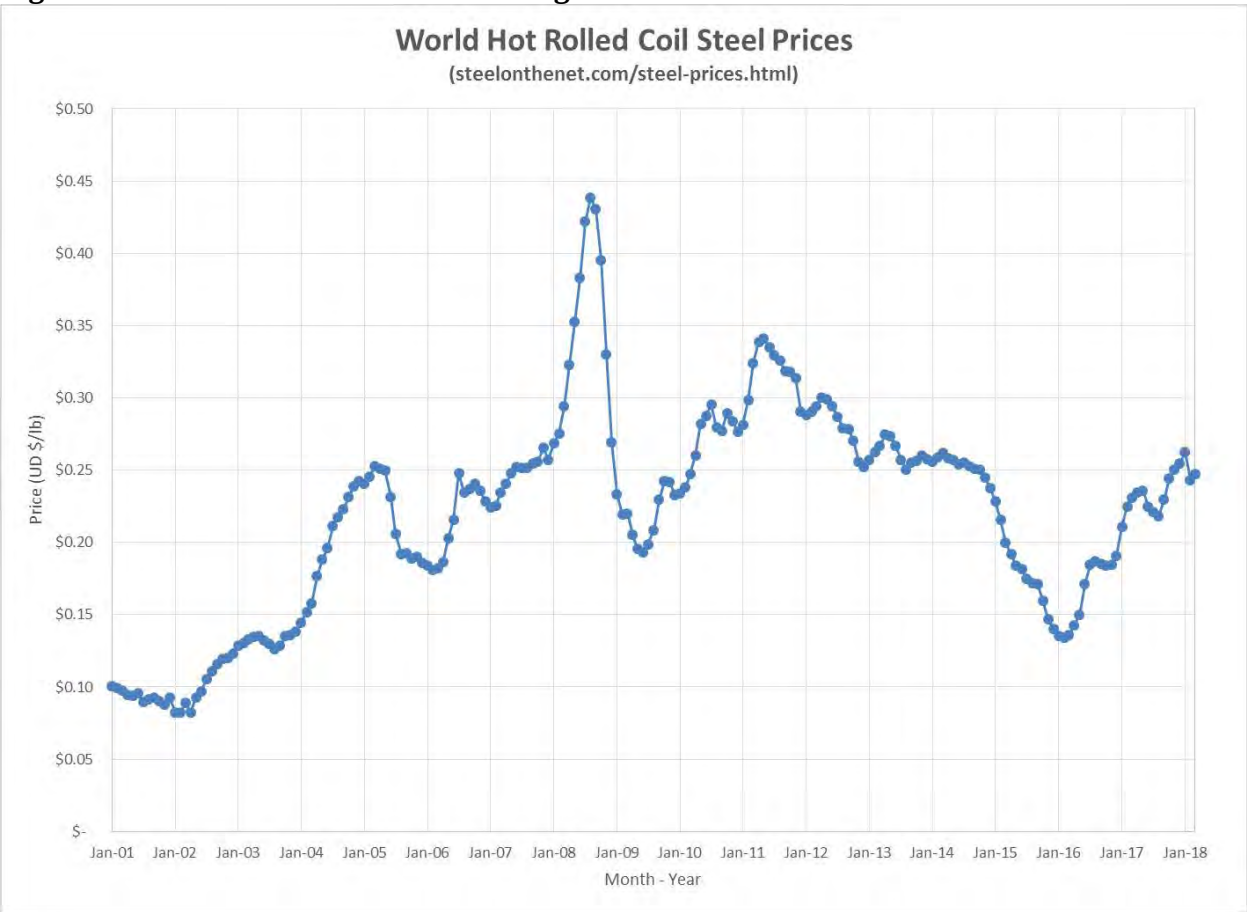


Figure 6.2 - Historic Carbon Steel Pricing



Prices for solar PV modules and balance of plant costs have come down since the 2017 IRP. Real prices are projected to continue to decline based upon technological and manufacturing improvements, but tariffs on Chinese imports and high demand for PV modules ahead of the phase out of the federal investment tax credits (ITC) for solar projects creates some degree of uncertainty in the solar market. The 2019 IRP anticipates the cost of new solar projects to decline approximately five percent per year during next three years and then to decline at a rate of approximately one percent per year beginning in year four.

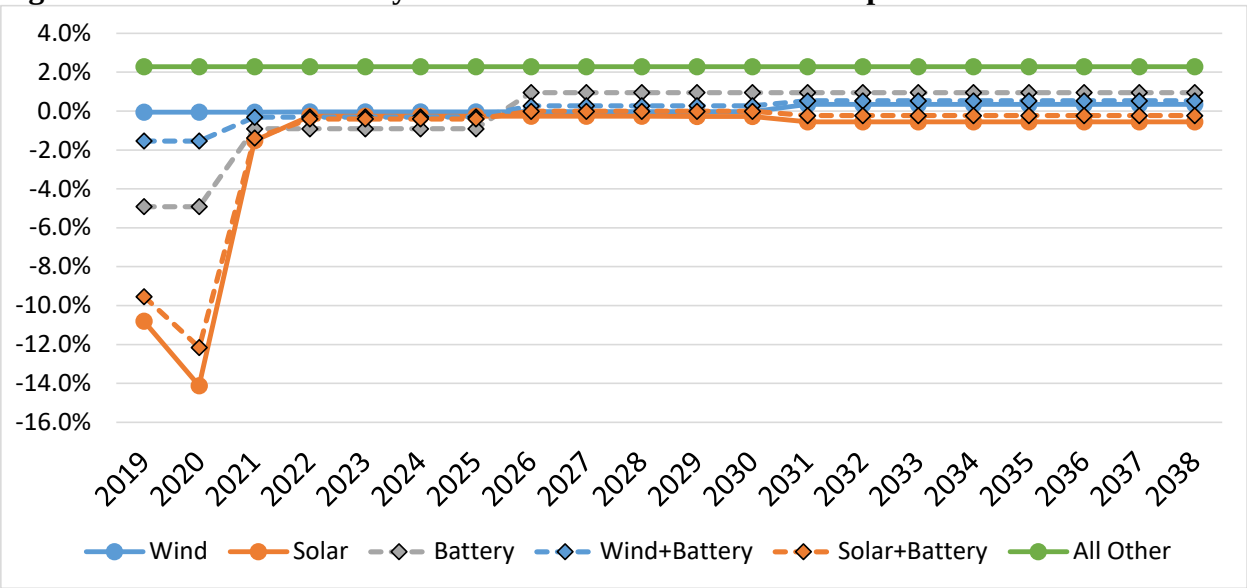
Some generation technologies, such as integrated gasification combined cycle (IGCC), have shown significant cost uncertainty because only a few units have been built and operated. Recent experience with the significant cost overruns on IGCC projects such as Southern Company's Kemper County IGCC plant illustrate the difficulty in accurately estimating capital costs of these resource options. As these technologies mature and more plants are constructed, the costs of such new technologies may decrease relative to more mature options such as pulverized coal and natural gas-fueled plants.

The SSR does not include the potential for such capital cost reductions since the benefits are not expected to be realized until the next generation of new plants are built and operated. For example, construction and operating "experience curve" benefits for IGCC plants are not expected to be available until after their commercial operation dates. 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.

Figure 6.3 shows nominal year-by-year capital cost escalation rates for wind, solar, battery, wind+battery, solar+battery, and all other resources.

Figure 6.3 – Nominal Year-by-Year Escalation for Resource Capital Costs



Solar annual capital cost escalation rates are based on unweighted median scenarios from General Electric Renewable Energy, the U.S. Energy Administration, and Burns and McDonnell—note, rates for 2019 and 2020 are adjusted to calibrate levelized costs to be consistent with pricing received in the 2017S RFP.

Wind annual capital cost escalation rates are based on unweighted median scenarios from Energy+Environmental Economics, General Electric Renewable Energy, Berkley Labs, ArcTechnica, the Office of Energy Efficiency & Renewable Energy Administration, and Burns and McDonnell—note, rates for 2019 and 2020 are adjusted to calibrate levelized costs consistent with pricing received in the 2017R RFP. Annual capital cost escalation rates for batteries are based on data from Burns and McDonnell. All other resources are assumed to escalate at 2.28 percent per year.

Resource Options and Attributes

Table 6.1 lists the cost-and-performance attributes for supply-side resource options designated by generic, elevation-specific regions where resources could potentially be located:

- 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 6.2 and Table 6.3 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 2018 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/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 6.4 and Table 6.5.

Table 6.1 – 2019 Supply-Side Resource Table (2018$)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/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 x3, ISO	0	142	2023	30	1,570	7.54	27.14	9279	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2, ISO	0	231	2023	30	1,092	5.05	18.78	8725	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1, ISO	0	233	2023	35	704	5.50	13.28	9811	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6, ISO	0	111	2023	35	1,810	7.45	29.82	8272	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1, ISO	0	419	2024	40	1,469	1.76	20.52	6847	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO	0	51	2024	40	478	0.15	5.39	6847	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1, ISO	0	840	2025	40	1,060	1.67	13.79	6861	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO	0	102	2025	40	365	0.16	4.44	6861	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1, ISO	0	539	2024	40	1,218	1.70	17.66	6787	2.5	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1, ISO	0	63	2024	40	407	0.16	4.86	6787	0.8	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1, ISO	0	1,083	2025	40	881	1.62	12.00	6787	2.5	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1, ISO	0	126	2025	40	316	0.16	4.05	6787	0.8	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	1,500	138	2023	30	1,612	7.76	27.96	9228	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	1,500	221	2023	30	1,143	5.35	19.88	8689	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	1,500	221	2023	35	741	5.81	14.02	9792	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	1,500	111	2023	35	1,810	7.45	29.82	8272	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	1,500	396	2024	40	1,552	1.86	21.68	6788	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	1,500	51	2024	40	478	0.15	5.39	6788	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	1,500	795	2025	40	1,120	1.77	14.57	6800	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	1,500	102	2025	40	365	0.16	4.44	6800	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	1,500	510	2024	40	1,288	1.80	18.67	6732	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	1,500	63	2024	40	407	0.16	4.86	6732	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	1,500	1,023	2025	40	932	1.71	12.69	6732	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	1,500	126	2025	40	316	0.16	4.05	6732	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	3,000	131	2023	30	1,704	8.21	29.58	9232	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	3,000	209	2023	30	1,209	5.67	21.10	8687	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	3,000	210	2023	35	782	6.13	14.81	9799	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	3,000	111	2023	35	1,810	7.45	29.82	8273	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	3,000	375	2024	40	1,641	1.97	22.92	6762	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	3,000	51	2024	40	478	0.15	5.39	6762	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	3,000	752	2025	40	1,184	1.86	15.39	6775	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	3,000	102	2025	40	365	0.16	4.44	6775	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	3,000	482	2024	40	1,363	1.90	19.73	6690	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	3,000	63	2024	40	407	0.16	4.86	6690	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	3,000	967	2025	40	986	1.81	13.41	6692	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	3,000	126	2025	40	316	0.16	4.05	6692	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	5,050	122	2023	30	1,829	8.85	31.86	9229	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	5,050	194	2023	30	1,305	6.14	22.82	8680	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	5,050	194	2023	35	843	6.61	15.97	9805	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	5,050	111	2023	35	1,810	7.45	29.82	8280	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	5,050	344	2024	40	1,788	2.12	24.74	6510	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	5,050	51	2024	40	478	0.15	5.39	6510	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	5,050	687	2025	40	1,297	2.01	16.63	6520	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	5,050	102	2025	40	365	0.16	4.44	6520	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	5,050	442	2024	40	1,485	2.05	21.26	6464	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	5,050	63	2024	40	407	0.16	4.86	6464	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	5,050	884	2025	40	1,079	1.95	14.45	6469	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	5,050	126	2025	40	316	0.16	4.05	6469	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	6,500	113	2023	30	1,975	9.60	34.56	9209	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	6,500	181	2023	30	1,394	6.45	24.00	8694	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	6,500	185	2023	35	887	6.96	16.81	9786	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	6,500	111	2023	35	1,810	7.75	31.04	8320	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	6,500	333	2024	40	1,843	2.25	26.20	6757	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	6,500	51	2024	40	478	0.15	5.39	6757	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	6,500	669	2025	40	1,330	2.13	17.61	6772	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	6,500	102	2025	40	365	0.16	4.44	6772	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	6,500	424	2024	40	1,549	2.15	22.33	6681	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	6,500	63	2024	40	407	0.16	4.86	6681	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	6,500	851	2025	40	1,120	2.05	15.18	6681	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	6,500	126	2025	40	316	0.16	4.06	6681	0.8	3.8	11	0.0006	0.0072	0.255	117

Table 6.1 – 2019 Supply-Side Resource Table (2018$) (Continued)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/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)
Coal	SCPC with CCS	4,500	526	2036	40	6,462	7.00	72.22	13087	5.0	5.0	1,004	0.009	0.070	0.022	20.5
Coal	IGCC with CCS	4,500	466	2036	40	6,257	11.77	58.20	10823	8.0	7.0	394	0.009	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW	4,500	-139	2033	20	1,419	6.47	77.76	14372	5.0	5.0	1,004	0.005	0.070	1.200	20.5
Coal	SCPC with CCS	6,500	692	2036	40	7,318	7.58	67.09	13242	5.0	5.0	1,004	0.009	0.070	0.022	20.5
Coal	IGCC with CCS	6,500	456	2036	40	7,085	14.11	63.40	11047	8.0	7.0	394	0.009	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW	6,500	-139	2031	20	1,607	7.00	72.22	14372	5.0	5.0	1,004	0.005	0.070	1.200	20.5
Geothermal	Blundell Dual Flash 90% CF	4,500	35	2021	40	5,708	1.16	103.85	n/a	5.0	5.0	10	n/a	n/a	n/a	n/a
Geothermal	Greenfield Binary 90% CF	4,500	43	2023	40	5,973	1.16	103.85	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Geothermal	Generic Geothermal PPA 90% CF	4,500	30	2021	20	0	77.34	0.00	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 37.1% CF WA, 2020	4,500	200	2020	30	1,354	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 37.1% CF OR, 2020	1,500	200	2020	30	1,334	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 37.1% CF ID, 2020	4,500	200	2020	30	1,358	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 29.5% CF UT, 2020	6,500	200	2020	30	1,301	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 43.6% CF WY, 2020	1,500	240	2020	30	1,301	0.65	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 100 MWh	4,500	200	2023	30	1,738	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 100 MWh	1,500	200	2023	30	1,765	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 100 MWh	4,500	200	2023	30	1,735	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 100 MWh	6,500	200	2023	30	1,730	0.65	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 100 MWh	1,500	200	2023	30	1,772	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 200 MWh	4,500	200	2023	30	1,880	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 200 MWh	1,500	200	2023	30	1,917	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 200 MWh	4,500	200	2023	30	1,877	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 200 MWh	6,500	200	2023	30	1,872	0.65	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 200 MWh	1,500	200	2023	30	1,924	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 400 MWh	4,500	200	2023	30	2,158	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 400 MWh	1,500	200	2023	30	2,214	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 400 MWh	4,500	200	2023	30	2,155	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 400 MWh	6,500	200	2023	30	2,150	0.65	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 400 MWh	1,500	200	2023	30	2,221	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Idaho Falls, ID, 50 MW, 28.1% CF	4,700	50	2021	25	1,366	0.00	21.72	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Idaho Falls, ID, 200 MW, 2021, 28.1% CF	4,700	200	2021	25	1,271	0.00	21.72	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Lakeview, OR, 50 MW, 2021, 29.7% CF	4,800	50	2021	25	1,424	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Lakeview, OR, 200 MW, 2021, 29.7% CF	4,800	200	2021	25	1,329	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Milford, UT, 50 MW, 2021, 32.5% CF	5,000	50	2021	25	1,363	0.00	22.32	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Milford, UT, 200 MW, 2021, 32.5% CF	5,000	200	2021	25	1,268	0.00	22.32	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Utah North, 200 MW, 2021, 30.1% CF	5,000	200	2021	25	1,266	0.00	21.13	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Rock Springs, WY, 50 MW, 2021, 30.1% CF	6,400	50	2021	25	1,360	0.00	21.13	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Rock Springs, WY, 200 MW, 2021, 30.1% CF	6,400	200	2021	25	1,266	0.00	21.13	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Yakima, WA, 50 MW, 2021, 26% CF	1,000	50	2021	25	1,422	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Yakima, WA, 200 MW, 2021, 26% CF	1,000	200	2021	25	1,327	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 20 MWh	4,700	50	2021	25	1,628	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 100 MWh	4,700	200	2021	25	1,470	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Idaho Falls, ID, 50 MW + 10 MW X 40 MWh	4,700	50	2021	25	1,756	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh	4,700	200	2021	25	1,614	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 80 MWh	4,700	50	2021	25	1,992	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 400 MWh	4,700	200	2021	25	1,897	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 50 MW + 10 MW X 20 MWh	4,800	50	2021	25	1,706	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 200 MW + 50 MW X 100 MWh	4,800	200	2021	25	1,543	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 50 MW + 10 MW X 40 MWh	4,800	50	2021	25	1,844	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh	4,800	200	2021	25	1,699	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 50 MW + 10 MW X 80 MWh	4,800	50	2021	25	2,098	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Lakeview, OR, 200 MW + 50 MW X 400 MWh	4,800	200	2021	25	2,004	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 50 MW + 10 MW X 20 MWh	5,000	50	2021	25	1,626	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 200 MW + 50 MW X 100 MWh	5,000	200	2021	25	1,467	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT 50 MW + 10 MW X 40 MWh	5,000	50	2021	25	1,754	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh	5,000	200	2021	25	1,612	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 50 MW + 10 MW X 80 MWh	5,000	50	2021	25	1,990	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 200 MW + 50 MW X 400 MWh	5,000	200	2021	25	1,895	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh	5,000	200	2021	25	1,609	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 20 MWh	6,400	50	2021	25	1,623	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 100 MWh	6,400	200	2021	25	1,464	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 40 MWh	6,400	50	2021	25	1,751	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh	6,400	200	2021	25	1,609	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 80 MWh	6,400	50	2021	25	1,987	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 400 MWh	6,400	200	2021	25	1,892	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Yakima, WA, 50 MW + 10 MW X 20 MWh	1,000	50	2021	25	1,704	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 200 MW + 50 MW X 100 MWh	1,000	200	2021	25	1,541	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 50 MW + 10 MW X 40 MWh	1,000	50	2021	25	1,842	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh	1,000	200	2021	25	1,697	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 50 MW + 10 MW X 80 MWh	1,000	50	2021	25	2,097	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 200 MW + 50 MW X 400 MWh	1,000	200	2021	25	2,002	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a

Table 6.1 – 2019 Supply-Side Resource Table (2018$) (Continued)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/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	Oregon PS, 400 MW X 3,800 MWh	4,457	400	2025	60	3,095	0.00	16.76	79%	3	7	0	0	0	0	0
Storage	Oregon PS joint ownership, 100 MW X 950 MWh	4,457	100	2025	60	3,099	0.00	16.76	79%	3	7	0	0	0	0	0
Storage	Washington PS, 1,200 MW X 16,800 MWh	500	1,200	2029	60	2,719	0.00	12.50	79%	3	7	0	0	0	0	0
Storage	Wyoming PS, 700 MW X 7,000 MWh	580	700	2027	60	3,255	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Wyoming PS, 400 MW X 3,400 MWh	6,000	400	2028	60	2,348	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Utah PS, 300 MW X 1,800 MWh	6,359	300	2025	60	2,991	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Idaho PS, 360 MW X 2,880 MWh	5,000	360	2031	60	2,680	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Idaho PS, 360 MW X 2,880 MWh	5,000	360	2031	60	2,680	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	CAES, 320 MW X 15,360 MWh	4,600	320	2022	30	1,625	0.00	7.01	4230 / 55%	1	3	0	0	0	0	117
Storage	Li-Ion 1 MW X 250 kWh	0	1	2020	15	1,473	11.42	8.29	88%	1	3	0	0	0	0	0
Storage	Li-Ion 1 MW X 2 MWh	0	1	2020	15	2,615	15.70	23.56	88%	1	3	0	0	0	0	0
Storage	Li-Ion 1 MW X 4 MWh	0	1	2020	15	3,412	14.98	35.23	88%	1	3	0	0	0	0	0
Storage	Li-Ion 1 MW X 8 MWh	0	1	2020	15	5,455	14.98	52.09	88%	1	3	0	0	0	0	0
Storage	Li-Ion 15 MW X 60 MWh	0	15	2020	15	1,766	15.07	11.50	88%	1	3	0	0	0	0	0
Storage	Flow 1 MW X 6 MWh	0	1	2021	15	3,996	0.00	32.00	65%	2	3	0	0	0	0	0
Nuclear	Advanced Fission	5,000	2,234	2030	40	6,765	11.75	101.62	10,710	7.7	7.3	96	0	0	0	0
Nuclear	Small Modular Reactor x 12	5,000	570	2028	40	6,028	15.50	173.35	10,710	7.7	7.3	65	0	0	0	0

Table 6.2 - Total Resource Cost for Supply-Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost 1/	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
SCCT Aero x3, ISO	0	$1,570	7.411%	$116.34	27.14	1.262%	0.34	31.94	59.42	$175.76
Intercooled SCCT Aero x2, ISO	0	$1,092	7.411%	$80.97	18.78	0.273%	0.05	30.03	48.87	$129.84
SCCT Frame "F" x1, ISO	0	$704	6.959%	$48.96	13.28	1.135%	0.15	33.77	47.21	$96.17
IC Recips x 6, ISO	0	$1,810	6.959%	$125.94	29.82	0.136%	0.04	28.47	58.33	$184.27
CCCT Dry "G/H", 1x1, ISO	0	$1,469	6.790%	$99.72	20.52	0.146%	0.03	23.57	44.12	$143.84
CCCT Dry "G/H", DF, 1x1, ISO	0	$478	6.790%	$32.45	5.39	0.000%	0.00	23.57	28.96	$61.42
CCCT Dry "G/H", 2x1, ISO	0	$1,060	6.790%	$71.98	13.79	0.146%	0.02	23.62	37.43	$109.41
CCCT Dry "G/H", DF, 2x1, ISO	0	$365	6.790%	$24.75	4.44	0.000%	0.00	23.62	28.05	$52.81
CCCT Dry "J/HA.02", 1x1, ISO	0	$1,218	6.790%	$82.69	17.66	0.000%	0.00	23.36	41.02	$123.70
CCCT Dry "J/HA.02", DF, 1x1, ISO	0	$407	6.790%	$27.67	4.86	0.000%	0.00	23.36	28.22	$55.89
CCCT Dry, "J/HA.02" 2X1, ISO	0	$881	6.790%	$59.80	12.00	0.146%	0.02	23.36	35.38	$95.18
CCCT Dry "J/HA.02", DF, 2X1, ISO	0	$316	6.790%	$21.45	4.05	0.000%	0.00	23.36	27.42	$48.86
SCCT Aero x3	1,500	$1,612	7.411%	$119.50	27.96	1.262%	0.35	31.76	60.07	$179.57
Intercooled SCCT Aero x2	1,500	$1,143	7.411%	$84.71	19.88	0.273%	0.05	29.91	49.85	$134.56
SCCT Frame "F" x1	1,500	$741	6.959%	$51.54	14.02	1.135%	0.16	33.71	47.89	$99.43
IC Recips x 6	1,500	$1,810	6.959%	$125.94	29.82	0.136%	0.04	28.47	58.33	$184.27
CCCT Dry "G/H", 1x1	1,500	$1,552	6.790%	$105.38	21.68	0.146%	0.03	23.37	45.08	$150.46
CCCT Dry "G/H", DF, 1x1	1,500	$478	6.790%	$32.45	5.39	0.000%	0.00	23.37	28.76	$61.21
CCCT Dry "G/H", 2x1	1,500	$1,120	6.790%	$76.07	14.57	0.146%	0.02	23.41	38.00	$114.07
CCCT Dry "G/H", DF, 2x1	1,500	$365	6.790%	$24.75	4.44	0.000%	0.00	23.41	27.84	$52.60
CCCT Dry "J/HA.02", 1x1	1,500	$1,288	6.790%	$87.46	18.67	0.000%	0.00	23.17	41.84	$129.30
CCCT Dry "J/HA.02", DF, 1x1	1,500	$407	6.790%	$27.67	4.86	0.000%	0.00	23.17	28.03	$55.70
CCCT Dry, "J/HA.02" 2X1	1,500	$932	6.790%	$63.30	12.69	0.146%	0.02	23.17	35.88	$99.17
CCCT Dry "J/HA.02", DF, 2X1	1,500	$316	6.790%	$21.45	4.05	0.000%	0.00	23.17	27.23	$48.67
SCCT Aero x3	3,000	$1,704	7.411%	$126.26	29.58	1.262%	0.37	16.94	46.89	$173.15
Intercooled SCCT Aero x2	3,000	$1,209	7.411%	$89.58	21.10	0.273%	0.06	15.94	37.10	$126.68
SCCT Frame "F" x1	3,000	$782	6.959%	$54.43	14.81	1.135%	0.17	17.98	32.95	$87.38
IC Recips x 6	3,000	$1,810	6.959%	$125.94	29.82	0.136%	0.04	15.18	45.03	$170.97
CCCT Dry "G/H", 1x1	3,000	$1,641	6.790%	$111.41	22.92	0.146%	0.03	23.28	46.23	$157.64
CCCT Dry "G/H", DF, 1x1	3,000	$478	6.790%	$32.45	5.39	0.000%	0.00	23.28	28.67	$61.12
CCCT Dry "G/H", 2x1	3,000	$1,184	6.790%	$80.42	15.39	0.146%	0.02	12.43	27.85	$108.27
CCCT Dry "G/H", DF, 2x1	3,000	$365	6.790%	$24.75	4.44	0.000%	0.00	12.43	16.87	$41.62
CCCT Dry "J/HA.02", 1x1	3,000	$1,363	6.790%	$92.58	19.73	0.000%	0.00	12.27	32.01	$124.58
CCCT Dry "J/HA.02", DF, 1x1	3,000	$407	6.790%	$27.67	4.86	0.000%	0.00	12.27	17.13	$44.80
CCCT Dry, "J/HA.02" 2X1	3,000	$986	6.790%	$66.98	13.41	0.146%	0.02	12.28	25.71	$92.69
CCCT Dry "J/HA.02", DF, 2X1	3,000	$316	6.790%	$21.45	4.05	0.000%	0.00	12.28	16.33	$37.78

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost 1/	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
SCCT Aero x3	5,050	$1,829	7.411%	$135.58	31.86	1.262%	0.40	14.06	46.32	$181.90
Intercooled SCCT Aero x2	5,050	$1,305	7.411%	$96.74	22.82	0.273%	0.06	13.22	36.10	$132.84
SCCT Frame "F" x1	5,050	$843	6.959%	$58.69	15.97	1.135%	0.18	14.93	31.08	$89.77
IC Recips x 6	5,050	$1,810	6.959%	$125.94	29.82	0.136%	0.04	12.61	42.47	$168.41
CCCT Dry "G/H", 1x1	5,050	$1,788	6.790%	$121.40	24.74	0.146%	0.04	9.91	34.69	$156.09
CCCT Dry "G/H", DF, 1x1	5,050	$478	6.790%	$32.45	5.39	0.000%	0.00	9.91	15.30	$47.76
CCCT Dry "G/H", 2x1	5,050	$1,297	6.790%	$88.06	16.63	0.146%	0.02	9.93	26.58	$114.64
CCCT Dry "G/H", DF, 2x1	5,050	$365	6.790%	$24.75	4.44	0.000%	0.00	9.93	14.37	$39.12
CCCT Dry "J/HA.02", 1x1	5,050	$1,485	6.790%	$100.84	21.26	0.000%	0.00	9.84	31.10	$131.95
CCCT Dry "J/HA.02", DF, 1x1	5,050	$407	6.790%	$27.67	4.86	0.000%	0.00	9.84	14.70	$42.37
CCCT Dry, "J/HA.02" 2X1	5,050	$1,079	6.790%	$73.29	14.45	0.146%	0.02	9.85	24.33	$97.61
CCCT Dry "J/HA.02", DF, 2X1	5,050	$316	6.790%	$21.45	4.05	0.000%	0.00	9.85	13.91	$35.35
SCCT Aero x3	6,500	$1,975	7.411%	$146.35	34.56	1.262%	0.44	9.13	44.13	$190.47
Intercooled SCCT Aero x2	6,500	$1,394	7.411%	$103.31	24.00	0.273%	0.07	8.62	32.68	$136.00
SCCT Frame "F" x1	6,500	$887	6.959%	$61.71	16.81	1.135%	0.19	9.70	26.70	$88.42
IC Recips x 6	6,500	$1,810	6.959%	$125.94	31.04	0.136%	0.04	8.24	39.33	$165.27
CCCT Dry "G/H", 1x1	6,500	$1,843	6.790%	$125.17	26.20	0.146%	0.04	20.66	46.90	$172.07
CCCT Dry "G/H", DF, 1x1	6,500	$478	6.790%	$32.45	5.39	0.000%	0.00	20.66	26.05	$58.50
CCCT Dry "G/H", 2x1	6,500	$1,330	6.790%	$90.33	17.61	0.146%	0.03	6.71	24.34	$114.67
CCCT Dry "G/H", DF, 2x1	6,500	$365	6.790%	$24.75	4.44	0.000%	0.00	6.71	11.15	$35.90
CCCT Dry "J/HA.02", 1x1	6,500	$1,549	6.790%	$105.16	22.33	0.000%	0.00	6.62	28.95	$134.11
CCCT Dry "J/HA.02", DF, 1x1	6,500	$407	6.790%	$27.67	4.86	0.000%	0.00	6.62	11.48	$39.15
CCCT Dry, "J/HA.02" 2X1	6,500	$1,120	6.790%	$76.08	15.18	0.146%	0.02	6.62	21.82	$97.90
CCCT Dry "J/HA.02", DF, 2X1	6,500	$316	6.790%	$21.45	4.06	0.000%	0.00	6.62	10.68	$32.12
Blundell Dual Flash 90% CF	4,500	$5,708	6.185%	$0.00	103.85	0.918%	0.95	0.00	104.80	$104.80
Generic Geothermal PPA 90% CF	4,500	$0	6.185%	$0.00	0.00	0.000%	0.00	0.00	0.00	$0.00
3.6 MW Wind turbine 37.1% CF WA, 2020 (100% PTC)	4,500	$1,354	6.899%	$93.42	27.99	2.902%	0.81	0.00	28.80	$122.22
3.6 MW Wind turbine 37.1% CF OR, 2020 (100% PTC)	1,500	$1,334	6.899%	$92.01	27.99	2.902%	0.81	0.00	28.80	$120.81
3.6 MW Wind turbine 37.1% CF ID, 2020 (100% PTC)	4,500	$1,358	6.899%	$93.71	27.99	2.902%	0.81	0.00	28.80	$122.52
3.6 MW Wind turbine 29.5% CF UT, 2020 (100% PTC)	6,500	$1,301	6.899%	$89.79	27.99	2.902%	0.81	0.00	28.80	$118.59
3.6 MW Wind turbine 43.6% CF WY, 2020 (100% PTC)	1,500	$1,301	6.899%	$89.79	27.99	2.902%	0.81	0.00	28.80	$118.59
3.6 MW Wind turbine 37.1% CF WA,2023 (40% PTC)	4,500	$1,354	6.899%	$93.42	27.99	2.902%	0.81	0.00	28.80	$122.22
3.6 MW Wind turbine 37.1% CF OR, 2023 (40% PTC)	1,500	$1,334	6.899%	$92.01	27.99	2.902%	0.81	0.00	28.80	$120.81
3.6 MW Wind turbine 37.1% CF ID, 2023 (40% PTC)	4,500	$1,358	6.899%	$93.71	27.99	2.902%	0.81	0.00	28.80	$122.52
3.6 MW Wind turbine 29.5% CF UT, 2023 (40% PTC)	6,500	$1,301	6.899%	$89.79	27.99	2.902%	0.81	0.00	28.80	$118.59

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost 1/	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 200 MWh	4,500	$1,880	6.899%	$129.66	29.88	2.902%	0.87	0.00	30.74	$160.41
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 200 MWh	1,500	$1,917	6.899%	$132.26	29.88	2.902%	0.87	0.00	30.74	$163.00
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 200 MWh	4,500	$1,877	6.899%	$129.51	29.88	2.902%	0.87	0.00	30.74	$160.25
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 200 MWh	6,500	$1,872	6.899%	$129.12	29.88	2.902%	0.87	0.00	30.74	$159.86
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 200 MWh	1,500	$1,924	6.899%	$132.71	29.88	2.902%	0.87	0.00	30.74	$163.45
PV Idaho Falls, ID, 200 MW, 2021, 28.1% CF (30% ITC)	4,500	$1,271	7.712%	$98.02	21.72	1.379%	0.30	0.00	22.02	$120.04
PV Lakeview, OR, 200 MW, 2021, 29.7% CF (30% ITC)	4,800	$1,329	7.712%	$102.53	22.35	1.379%	0.31	0.00	22.66	$125.19
PV Milford, UT, 200 MW, 2021, 32.5% CF (30% ITC)	4,500	$1,268	7.712%	$97.83	22.32	1.379%	0.31	0.00	22.63	$120.46
PV Utah North, 200 MW, 2021, 30.1% CF (30% ITC)	4,501	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
PV Rock Springs, WY, 200 MW, 2021, 30.1% CF (30% ITC)	4,800	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
PV Yakima, WA, 200 MW, 2021, 26% CF (30% ITC)	4,802	$1,327	7.712%	$102.36	22.35	1.379%	0.31	0.00	22.66	$125.02
PV Idaho Falls, ID, 200 MW, 2026, 28.1% CF (10% ITC)	4,802	$1,271	7.712%	$98.02	21.72	1.379%	0.30	0.00	22.02	$120.04
PV Lakeview, OR, 200 MW, 2026, 29.7% CF (10% ITC)	4,802	$1,329	7.712%	$102.53	22.35	1.379%	0.31	0.00	22.66	$125.19
PV Milford, UT, 200 MW, 2026, 32.5% CF (10% ITC)	4,802	$1,268	7.712%	$97.83	22.32	1.379%	0.31	0.00	22.63	$120.46
PV Utah North, 200 MW, 2021, 30.1% CF (10% ITC)	4,803	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
PV Rock Springs, WY, 200 MW, 2026, 30.1% CF (10% ITC)	4,802	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
PV Yakima, WA, 200 MW, 2026, 26% CF (10% ITC)	4,802	$1,327	7.712%	$102.36	22.35	1.379%	0.31	0.00	22.66	$125.02
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (30% ITC)	4,802	$1,614	7.712%	$124.48	24.24	1.379%	0.33	0.00	24.57	$149.05
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (30% ITC)	4,802	$1,699	7.712%	$131.01	24.24	1.379%	0.33	0.00	24.57	$155.58
PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (30% ITC)	4,802	$1,612	7.712%	$124.29	24.24	1.379%	0.33	0.00	24.57	$148.86
PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (30% ITC)	4,803	$1,609	7.712%	$124.08	24.24	1.379%	0.33	0.00	24.57	$148.65
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (30% ITC)	4,802	$1,609	7.712%	$124.08	24.24	1.379%	0.33	0.00	24.57	$148.65
PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (30% ITC)	4,802	$1,697	7.712%	$130.86	24.24	1.379%	0.33	0.00	24.57	$155.43
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (10% ITC)	4,802	$1,614	7.712%	$124.48	24.24	1.379%	0.33	0.00	24.57	$149.05
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (10% ITC)	4,802	$1,699	7.712%	$131.01	24.24	1.379%	0.33	0.00	24.57	$155.58
PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (10% ITC)	4,802	$1,612	7.712%	$124.29	24.24	1.379%	0.33	0.00	24.57	$148.86
PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (10% ITC)	4,803	$1,609	7.712%	$124.08	24.24	1.379%	0.33	0.00	24.57	$148.65
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (10% ITC)	4,802	$1,609	7.712%	$124.08	24.24	1.379%	0.33	0.00	24.57	$148.65
PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (10% ITC)	4,802	$1,697	7.712%	$130.86	24.24	1.379%	0.33	0.00	24.57	$155.43
Oregon PS, 400 MW X 3,800 MWh	4,457	$3,095	6.142%	$190.09	16.76	0.000%	0.00	0.00	16.76	$206.85
Oregon PS joint ownership, 100 MW X 950 MWh	580	$3,099	6.142%	$190.38	16.76	0.000%	0.00	0.00	16.76	$207.14
Washington PS, 1,200 MW X 16,800 MWh	580	$2,719	6.142%	$166.98	12.50	0.000%	0.00	0.00	12.50	$179.48
Wyoming PS, 700 MW X 7,000 MWh	6,359	$3,255	6.142%	$199.94	17.00	0.000%	0.00	0.00	17.00	$216.94
Wyoming PS, 400 MW X 3,400 MWh	6,360	$2,348	6.142%	$144.20	17.00	0.000%	0.00	0.00	17.00	$161.20
Utah PS, 300 MW X 1,800 MWh	6,360	$2,991	6.142%	$183.72	17.00	0.000%	0.00	0.00	17.00	$200.72
Idaho PS, 360 MW X 2,880 MWh	6,361	$2,680	6.142%	$164.61	17.00	0.000%	0.00	0.00	17.00	$181.61
CAES, 320 MW X 15,360 MWh	4,640	$1,625	7.411%	$120.41	7.01	0.000%	0.00	0.00	7.01	$127.41
Li-Ion 15 MW X 60 MWh	6,359	$1,766	11.126%	$196.44	11.50	0.000%	0.00	0.00	11.50	$207.93

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost 1/	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
Brownfield Site										
Dave Johnston										
SCCT Frame "F" x1	5,050	$709	6.959%	$49.31	15.97	1.135%	0.18	14.93	31.08	$80.39
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	6,400	$1,301	6.899%	$89.79	27.99	2.902%	0.81	0.00	28.80	$118.59
CCCT Dry "J/HA.02", 1x1	5,050	$1,342	6.790%	$91.12	21.26	0.000%	0.00	19.76	41.02	$132.14
CCCT Dry "J/HA.02", DF, 1x1	5,050	$368	6.790%	$25.00	4.86	0.000%	0.00	19.76	24.62	$49.62
Hunter										
SCCT Frame "F" x1	5,050	$709	6.959%	$49.31	15.97	1.135%	0.18	14.93	31.08	$80.39
PV, 200 MW, 2026, 32.5% CF (10% ITC)	5,000	$1,268	7.712%	$97.83	22.32	1.379%	0.31	0.00	22.63	$120.46
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	5,000	$1,612	7.712%	$124.29	24.24	1.379%	0.33	0.00	24.57	$148.86
CCCT Dry "J/HA.02", 1x1	5,050	$1,342	6.790%	$91.12	21.26	0.000%	0.00	9.84	31.10	$122.22
CCCT Dry "J/HA.02", DF, 1x1	5,050	$368	6.790%	$25.00	4.86	0.000%	0.00	9.84	14.70	$39.70
Huntington										
SCCT Frame "F" x1	5,050	$709	6.959%	$49.31	15.97	1.135%	0.18	14.93	31.08	$80.39
PV, 200 MW, 2026, 32.5% CF (10% ITC)	5,000	$1,268	7.712%	$97.83	22.32	1.379%	0.31	0.00	22.63	$120.46
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	5,000	$1,612	7.712%	$124.29	24.24	1.379%	0.33	0.00	24.57	$148.86
CCCT Dry "J/HA.02", 1x1	5,050	$1,342	6.790%	$91.12	21.26	0.000%	0.00	9.84	31.10	$122.22
CCCT Dry "J/HA.02", DF, 1x1	5,050	$368	6.790%	$25.00	4.86	0.000%	0.00	9.84	14.70	$39.70
Jim Bridger										
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	6,400	$1,301	6.899%	$89.79	27.99	2.902%	0.81	0.00	28.80	$118.59
Wind + Stor, 200 MW+ 50 MW | 400 MWh	6,500	$2,150	6.899%	$148.30	31.03	2.902%	0.90	0.00	31.93	$180.23
SCCT Frame "F" x1	6,500	$745	6.959%	$51.85	16.81	1.135%	0.19	9.70	26.70	$78.56
PV, 200 MW, 2026, 32.5% CF (10% ITC)	6,400	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	6,400	$1,609	7.712%	$124.08	24.24	1.379%	0.33	0.00	24.57	$148.65
CCCT Dry "J/HA.02", 1x1	6,500	$1,399	6.790%	$95.01	22.33	0.000%	0.00	6.62	28.95	$123.97
CCCT Dry "J/HA.02", DF, 1x1	6,500	$368	6.790%	$25.00	4.86	0.000%	0.00	6.62	11.48	$36.48
Naughton										
SCCT Frame "F" x1	6,500	$745	6.959%	$51.85	16.81	1.135%	0.19	14.90	31.91	$83.76
PV 200 MW, 2026, 30.1% CF (10% ITC)	6,400	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
CCCT Dry "J/HA.02", 1x1	6,500	$1,399	6.790%	$95.01	22.33	0.000%	0.00	10.17	32.51	$127.52
CCCT Dry "J/HA.02", DF, 1x1	6,500	$368	6.790%	$25.00	4.86	0.000%	0.00	10.17	15.03	$40.03
Wyodak										
SCCT Frame "F" x1	6,500	$745	6.959%	$51.85	16.81	1.135%	0.19	29.92	46.92	$98.78

1/ Input into IRP SO and PAR Model
Results presented without credits
Information Presented is Illustrative

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Resources not Modeled in 2019 IRP

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
SCPC with CCS	4,500	$6,462	6.726%	$434.61	72.22	5.541%	4.00	0.00	76.23	$510.84
IGCC with CCS	4,500	$6,257	6.533%	$408.75	58.20	0.000%	0.00	0.00	58.20	$466.95
PC CCS retrofit @ 500 MW	4,500	$1,419	6.726%	$95.42	77.76	0.000%	0.00	0.00	77.76	$173.17
SCPC with CCS	6,500	$7,318	6.726%	$492.18	67.09	5.541%	0.00	0.00	67.09	$559.27
IGCC with CCS	6,500	$7,085	6.533%	$462.83	63.40	0.000%	0.00	0.00	63.40	$526.23
PC CCS retrofit @ 500 MW	6,500	$1,607	6.712%	$107.84	72.22	0.000%	0.00	0.00	72.22	$180.07
Greenfield Binary 90% CF	4,500	$5,973	6.185%	$369.45	103.85	0.918%	0.95	0.00	104.80	$474.26
Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 100 MWh	4,500	$1,738	6.899%	$119.87	29.18	2.902%	0.85	0.00	30.03	$149.90
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 100 MWh	1,500	$1,765	6.899%	$121.79	29.18	2.902%	0.85	0.00	30.03	$151.83
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 100 MWh	4,500	$1,735	6.899%	$119.71	29.18	2.902%	0.85	0.00	30.03	$149.74
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 100 MWh	6,500	$1,730	6.899%	$119.32	29.18	2.902%	0.85	0.00	30.03	$149.35
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 100 MWh	1,500	$1,772	6.899%	$122.24	29.18	2.902%	0.85	0.00	30.03	$152.27
Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 400 MWh	4,500	$2,158	6.899%	$148.85	31.03	2.902%	0.90	0.00	31.93	$180.78
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 400 MWh	1,500	$2,214	6.899%	$152.75	31.03	2.902%	0.90	0.00	31.93	$184.68
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 400 MWh	4,500	$2,155	6.899%	$148.69	31.03	2.902%	0.90	0.00	31.93	$180.62
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 400 MWh	6,500	$2,150	6.899%	$148.30	31.03	2.902%	0.90	0.00	31.93	$180.23
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 400 MWh	1,500	$2,221	6.899%	$153.22	31.03	2.902%	0.90	0.00	31.93	$185.15
PV Idaho Falls, ID, 50 MW, 28.1% CF (30% ITC)	4,500	$1,366	7.712%	$105.31	21.72	1.379%	0.30	0.00	22.02	$127.33
PV Lakeview, OR, 50 MW, 2021, 29.7% CF (30% ITC)	4,800	$1,424	7.712%	$109.83	22.35	1.379%	0.31	0.00	22.66	$132.48
PV Milford, UT, 50 MW, 2021, 32.5% CF (30% ITC)	4,500	$1,363	7.712%	$105.12	22.32	1.379%	0.31	0.00	22.63	$127.75
PV Rock Springs, WY, 50 MW, 2021, 30.1% CF (30% ITC)	4,800	$1,360	7.712%	$104.91	21.13	1.379%	0.29	0.00	21.42	$126.34
PV Yakima, WA, 50 MW, 2021, 26% CF (30% ITC)	4,801	$1,422	7.712%	$109.66	22.35	1.379%	0.31	0.00	22.66	$132.31
PV Idaho Falls, ID, 50 MW, 2026, 28.1% CF (10% ITC)	4,802	$1,366	7.712%	$105.31	21.72	1.379%	0.30	0.00	22.02	$127.33
PV Lakeview, OR, 50 MW, 2026, 29.7% CF (10% ITC)	4,802	$1,424	7.712%	$109.83	22.35	1.379%	0.31	0.00	22.66	$132.48
PV Milford, UT, 50 MW, 2026, 32.5% CF (10% ITC)	4,802	$1,363	7.712%	$105.12	22.32	1.379%	0.31	0.00	22.63	$127.75
PV Rock Springs, WY, 50 MW, 2026, 30.1% CF (10% ITC)	4,802	$1,360	7.712%	$104.91	21.13	1.379%	0.29	0.00	21.42	$126.34
PV Yakima, WA, 50 MW, 2026, 26% CF (10% ITC)	4,802	$1,422	7.712%	$109.66	22.35	1.379%	0.31	0.00	22.66	$132.31
PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 20 MWh (30% ITC)	4,802	$1,628	7.712%	$125.57	23.48	1.379%	0.32	0.00	23.81	$149.37
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 100 MWh (30% ITC)	4,802	$1,470	7.712%	$113.34	22.91	1.379%	0.32	0.00	23.23	$136.57
PV + Stor,, Idaho Falls, ID, 50 MW + 10 MW X 40 MWh (30% ITC)	4,802	$1,756	7.712%	$135.46	25.03	1.379%	0.35	0.00	25.38	$160.83
PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 80 MWh (30% ITC)	4,802	$1,992	7.712%	$153.67	26.46	1.379%	0.36	0.00	26.82	$180.49
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 400 MWh (30% ITC)	4,802	$1,897	7.712%	$146.31	25.36	1.379%	0.35	0.00	25.71	$172.01
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 20 MWh (30% ITC)	4,802	$1,706	7.712%	$131.56	23.48	1.379%	0.32	0.00	23.81	$155.37
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 100 MWh (30% ITC)	4,802	$1,543	7.712%	$119.00	22.91	1.379%	0.32	0.00	23.23	$142.23
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 40 MWh (30% ITC)	4,802	$1,844	7.712%	$142.22	25.03	1.379%	0.35	0.00	25.38	$167.59
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 80 MWh (30% ITC)	4,802	$2,098	7.712%	$161.83	26.46	1.379%	0.36	0.00	26.82	$188.66
PV + Stor,, Lakeview, OR, 200 MW + 50 MW X 400 MWh (30% ITC)	4,802	$2,004	7.712%	$154.52	25.36	1.379%	0.35	0.00	25.71	$180.23
PV + Stor,, Milford, UT, 50 MW + 10 MW X 20 MWh (30% ITC)	4,802	$1,626	7.712%	$125.37	23.48	1.379%	0.32	0.00	23.81	$149.18
PV + Stor,, Milford, UT, 200 MW + 50 MW X 100 MWh (30% ITC)	4,802	$1,467	7.712%	$113.14	22.91	1.379%	0.32	0.00	23.23	$136.37
PV + Stor,, Milford, UT 50 MW + 10 MW X 40 MWh (30% ITC)	4,802	$1,754	7.712%	$135.27	25.03	1.379%	0.35	0.00	25.38	$160.64
PV + Stor,, Milford, UT, 50 MW + 10 MW X 80 MWh (30% ITC)	4,802	$1,990	7.712%	$153.48	26.46	1.379%	0.36	0.00	26.82	$180.30
PV + Stor,, Milford, UT, 200 MW + 50 MW X 400 MWh (30% ITC)	4,802	$1,895	7.712%	$146.11	25.36	1.379%	0.35	0.00	25.71	$171.82
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 20 MWh (30% ITC)	4,802	$1,623	7.712%	$125.17	23.48	1.379%	0.32	0.00	23.81	$148.97
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 100 MWh (30% ITC)	4,802	$1,464	7.712%	$112.94	22.91	1.379%	0.32	0.00	23.23	$136.17
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 40 MWh (30% ITC)	4,802	$1,751	7.712%	$135.06	25.03	1.379%	0.35	0.00	25.38	$160.43
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 80 MWh (30% ITC)	4,802	$1,987	7.712%	$153.27	26.46	1.379%	0.36	0.00	26.82	$180.09
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 400 MWh (30% ITC)	4,802	$1,892	7.712%	$145.91	25.36	1.379%	0.35	0.00	25.71	$171.61
PV + Stor,, Yakima, WA, 50 MW + 10 MW X 20 MWh (30% ITC)	4,802	$1,704	7.712%	$131.40	23.48	1.379%	0.32	0.00	23.81	$155.21
PV + Stor, Yakima, WA, 200 MW + 50 MW X 100 MWh (30% ITC)	4,802	$1,541	7.712%	$118.85	22.91	1.379%	0.32	0.00	23.23	$142.08
PV + Stor, Yakima, WA, 50 MW + 10 MW X 40 MWh (30% ITC)	4,802	$1,842	7.712%	$142.07	25.03	1.379%	0.35	0.00	25.38	$167.45
PV + Stor, Yakima, WA, 50 MW + 10 MW X 80 MWh (30% ITC)	4,802	$2,097	7.712%	$161.70	26.46	1.379%	0.36	0.00	26.82	$188.53
PV + Stor, Yakima, WA, 200 MW + 50 MW X 400 MWh (30% ITC)	4,802	$2,002	7.712%	$154.39	25.36	1.379%	0.35	0.00	25.71	$180.10
Li-Ion 1 MW X 250 kWh	6,359	$1,473	11.126%	$163.90	8.29	0.000%	0.00	0.00	8.29	$172.19
Li-Ion 1 MW X 2 MWh	6,359	$2,615	11.126%	$290.96	23.56	0.000%	0.00	0.00	23.56	$314.52
Li-Ion 1 MW X 4 MWh	6,359	$3,412	11.126%	$379.58	35.23	0.000%	0.00	0.00	35.23	$414.82
Li-Ion 1 MW X 8 MWh	6,359	$5,455	11.126%	$606.91	52.09	0.000%	0.00	0.00	52.09	$659.00
Flow 1 MW X 6 MWh	6,360	$3,996	11.126%	$444.59	32.00	0.000%	0.00	0.00	32.00	$476.59
Advanced Fission	5,000	$6,765	6.639%	$449.13	101.62	5.687%	5.78	0.00	107.40	$556.53
Small Modular Reactor x 12	5,000	$6,028	6.639%	$400.24	173.35	11.228%	19.46	0.00	192.82	$593.06

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Convert to $/MWh					Variable Costs ($/MWh)					Total Costs and Credits ($/MWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 2/	Total Fixed ($/MWh)	Storage Efficiency	¢/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - with PTC / ITC Credits
SCCT Aero x3, ISO	0	33%	60.80	na	320	29.73	7.54	11.48%	0.87	-	-	98.93	-	98.93
Intercooled SCCT Aero x2, ISO	0	33%	44.91	na	320	27.96	5.05	13.23%	0.67	-	-	78.59	-	78.59
SCCT Frame "F" x1, ISO	0	33%	33.27	na	320	31.44	5.50	11.48%	0.63	-	-	70.84	-	70.84
IC Recips x 6, ISO	0	33%	63.74	na	320	26.51	7.45	8.73%	0.65	-	-	98.35	-	98.35
CCCT Dry "G/H", 1x1, ISO	0	78%	21.05	na	320	21.94	1.76	10.21%	0.18	-	-	44.93	-	44.93
CCCT Dry "G/H", DF, 1x1, ISO	0	12%	58.42	na	320	21.94	0.15	0.00%	0.00	-	-	80.52	-	80.52
CCCT Dry "G/H", 2x1, ISO	0	78%	16.01	na	320	21.99	1.67	10.79%	0.18	-	-	39.85	-	39.85
CCCT Dry "G/H", DF, 2x1, ISO	0	12%	50.24	na	320	21.99	0.16	0.00%	0.00	-	-	72.38	-	72.38
CCCT Dry "J/HA.02", 1x1, ISO	0	78%	18.10	na	320	21.75	1.70	10.21%	0.17	-	-	41.72	-	41.72
CCCT Dry "J/HA.02", DF, 1x1, ISO	0	12%	53.17	na	320	21.75	0.16	0.00%	0.00	-	-	75.07	-	75.07
CCCT Dry, "J/HA.02" 2X1, ISO	0	78%	13.93	na	320	21.75	1.62	10.79%	0.17	-	-	37.47	-	37.47
CCCT Dry "J/HA.02", DF, 2X1, ISO	0	12%	46.48	na	320	21.75	0.16	0.00%	0.00	-	-	68.39	-	68.39
SCCT Aero x3	1500	33%	62.12	na	320	29.57	7.76	11.48%	0.89	-	-	100.34	-	100.34
Intercooled SCCT Aero x2	1500	33%	46.55	na	320	27.84	5.35	13.23%	0.71	-	-	80.45	-	80.45
SCCT Frame "F" x1	1500	33%	34.40	na	320	31.38	5.81	11.48%	0.67	-	-	72.25	-	72.25
IC Recips x 6	1500	33%	63.74	na	320	26.51	7.45	8.73%	0.65	-	-	98.35	-	98.35
CCCT Dry "G/H", 1x1	1500	78%	22.02	na	320	21.75	1.86	10.21%	0.19	-	-	45.82	-	45.82
CCCT Dry "G/H", DF, 1x1	1500	12%	58.23	na	320	21.75	0.15	0.00%	0.00	-	-	80.14	-	80.14
CCCT Dry "G/H", 2x1	1500	78%	16.69	na	320	21.79	1.77	10.79%	0.19	-	-	40.44	-	40.44
CCCT Dry "G/H", DF, 2x1	1500	12%	50.04	na	320	21.79	0.16	0.00%	0.00	-	-	71.98	-	71.98
CCCT Dry "J/HA.02", 1x1	1500	78%	18.92	na	320	21.57	1.80	10.21%	0.18	-	-	42.48	-	42.48
CCCT Dry "J/HA.02", DF, 1x1	1500	12%	52.99	na	320	21.57	0.16	0.00%	0.00	-	-	74.71	-	74.71
CCCT Dry, "J/HA.02" 2X1	1500	78%	14.51	na	320	21.57	1.71	10.79%	0.18	-	-	37.98	-	37.98
CCCT Dry "J/HA.02", DF, 2X1	1500	12%	46.30	na	320	21.57	0.16	0.00%	0.00	-	-	68.03	-	68.03
SCCT Aero x3	3000	33%	59.90	na	324	29.90	8.21	11.48%	0.94	-	-	98.95	-	98.95
Intercooled SCCT Aero x2	3000	33%	43.82	na	324	28.14	5.67	13.23%	0.75	-	-	78.38	-	78.38
SCCT Frame "F" x1	3000	33%	30.23	na	324	31.74	6.13	11.48%	0.70	-	-	68.80	-	68.80
IC Recips x 6	3000	33%	59.14	na	324	26.80	7.45	8.73%	0.65	-	-	94.04	-	94.04
CCCT Dry "G/H", 1x1	3000	78%	23.07	na	324	21.90	1.97	10.21%	0.20	-	-	47.14	-	47.14
CCCT Dry "G/H", DF, 1x1	3000	12%	58.15	na	324	21.90	0.15	0.00%	0.00	-	-	80.20	-	80.20
CCCT Dry "G/H", 2x1	3000	78%	15.85	na	324	21.94	1.86	10.79%	0.20	-	-	39.86	-	39.86
CCCT Dry "G/H", DF, 2x1	3000	12%	39.60	na	324	21.94	0.16	0.00%	0.00	-	-	61.70	-	61.70
CCCT Dry "J/HA.02", 1x1	3000	78%	18.23	na	324	21.67	1.90	10.21%	0.19	-	-	42.00	-	42.00
CCCT Dry "J/HA.02", DF, 1x1	3000	12%	42.62	na	324	21.67	0.16	0.00%	0.00	-	-	64.44	-	64.44
CCCT Dry, "J/HA.02" 2X1	3000	78%	13.56	na	324	21.67	1.81	10.79%	0.19	-	-	37.24	-	37.24
CCCT Dry "J/HA.02", DF, 2X1	3000	12%	35.94	na	324	21.67	0.16	0.00%	0.00	-	-	57.77	-	57.77

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Convert to $/MWh					Variable Costs ($/MWh)					Total Costs and Credits ($/MWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	¢/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - with PTC / ITC Credits
SCCT Aero x3	5050	33%	62.92	na	327	30.14	8.85	11.48%	1.02	-	-	102.93	-	102.93
Intercooled SCCT Aero x2	5050	33%	45.95	na	327	28.35	6.14	13.23%	0.81	-	-	81.25	-	81.25
SCCT Frame "F" x1	5050	33%	31.05	na	327	32.02	6.61	11.48%	0.76	-	-	70.45	-	70.45
IC Recips x 6	5050	33%	58.26	na	327	27.04	7.45	8.73%	0.65	-	-	93.40	-	93.40
CCCT Dry "G/H", 1x1	5050	78%	22.84	na	327	21.26	2.12	10.21%	0.22	-	-	46.45	-	46.45
CCCT Dry "G/H", DF, 1x1	5050	12%	45.43	na	327	21.26	0.15	0.00%	0.00	-	-	66.85	-	66.85
CCCT Dry "G/H", 2x1	5050	78%	16.78	na	327	21.29	2.01	10.79%	0.22	-	-	40.30	-	40.30
CCCT Dry "G/H", DF, 2x1	5050	12%	37.21	na	327	21.29	0.16	0.00%	0.00	-	-	58.66	-	58.66
CCCT Dry "J/HA.02", 1x1	5050	78%	19.31	na	327	21.11	2.05	10.21%	0.21	-	-	42.68	-	42.68
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	40.31	na	327	21.11	0.16	0.00%	0.00	-	-	61.57	-	61.57
CCCT Dry, "J/HA.02" 2X1	5050	78%	14.29	na	327	21.13	1.95	10.79%	0.21	-	-	37.57	-	37.57
CCCT Dry "J/HA.02", DF, 2X1	5050	12%	33.63	na	327	21.13	0.16	0.00%	0.00	-	-	54.91	-	54.91
SCCT Aero x3	6500	33%	65.89	na	320	29.50	9.60	11.48%	1.10	-	-	106.09	-	106.09
Intercooled SCCT Aero x2	6500	33%	47.04	na	320	27.85	6.45	13.23%	0.85	-	-	82.20	-	82.20
SCCT Frame "F" x1	6500	33%	30.59	na	320	31.35	6.96	11.48%	0.80	-	-	69.69	-	69.69
IC Recips x 6	6500	33%	57.17	na	320	26.65	7.75	8.73%	0.68	-	-	92.25	-	92.25
CCCT Dry "G/H", 1x1	6500	78%	25.18	na	320	21.64	2.25	10.21%	0.23	-	-	49.31	-	49.31
CCCT Dry "G/H", DF, 1x1	6500	12%	55.65	na	320	21.64	0.15	0.00%	0.00	-	-	77.45	-	77.45
CCCT Dry "G/H", 2x1	6500	78%	16.78	na	320	21.69	2.13	10.79%	0.23	-	-	40.84	-	40.84
CCCT Dry "G/H", DF, 2x1	6500	12%	34.15	na	320	21.69	0.16	0.00%	0.00	-	-	56.00	-	56.00
CCCT Dry "J/HA.02", 1x1	6500	78%	19.63	na	320	21.40	2.15	10.21%	0.22	-	-	43.39	-	43.39
CCCT Dry "J/HA.02", DF, 1x1	6500	12%	37.24	na	320	21.40	0.16	0.00%	0.00	-	-	58.80	-	58.80
CCCT Dry, "J/HA.02" 2X1	6500	78%	14.33	na	320	21.40	2.05	10.79%	0.22	-	-	38.00	-	38.00
CCCT Dry "J/HA.02", DF, 2X1	6500	12%	30.56	na	320	21.40	0.16	0.00%	0.00	-	-	52.12	-	52.12
Blundell Dual Flash 90% CF	4500	90%	13.26	na	0	-	1.16	0.00%	0.00	-	-	14.42	(15.55)	(1.14)
Generic Geothermal PPA 90% CF	4500	90%	-	na	0	-	77.34	0.00%	0.00	-	-	77.34	-	77.34
3.6 MW Wind turbine 37.1% CF WA, 2020 (100% PTC)	4500	37%	37.61	na	0	-	10.00	0.00%	0.00	0.93	-	48.54	(15.55)	32.98
3.6 MW Wind turbine 37.1% CF OR, 2020 (100% PTC)	1500	37%	37.17	na	0	-	10.00	0.00%	0.00	0.93	-	48.10	(15.55)	32.55
3.6 MW Wind turbine 37.1% CF ID, 2020 (100% PTC)	4500	37%	37.70	na	0	-	0.00	0.00%	0.00	0.93	-	38.63	(15.55)	23.07
3.6 MW Wind turbine 29.5% CF UT, 2020 (100% PTC)	6500	30%	45.89	na	0	-	0.00	0.00%	0.00	0.93	-	46.82	(15.55)	31.27
3.6 MW Wind turbine 43.6% CF WY, 2020 (100% PTC)	1500	44%	31.05	na	0	-	0.65	0.00%	0.00	0.93	-	32.63	(15.55)	17.08
3.6 MW Wind turbine 37.1% CF WA,2023 (40% PTC)	4500	37%	37.61	na	0	-	10.00	0.00%	0.00	0.93	-	48.54	(6.22)	42.31
3.6 MW Wind turbine 37.1% CF OR, 2023 (40% PTC)	1500	37%	37.17	na	0	-	10.00	0.00%	0.00	0.93	-	48.10	(6.22)	41.88
3.6 MW Wind turbine 37.1% CF ID, 2023 (40% PTC)	4500	37%	37.70	na	0	-	0.00	0.00%	0.00	0.93	-	38.63	(6.22)	32.41
3.6 MW Wind turbine 29.5% CF UT, 2023 (40% PTC)	6500	30%	45.89	na	0	-	0.00	0.00%	0.00	0.93	-	46.82	(6.22)	40.60
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	1500	44%	31.05	na	0	-	0.65	0.00%	0.00	0.93	-	32.63	(6.22)	26.41

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)*

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Convert to $/MWh					Variable Costs ($/MWh)					Total Costs and Credits ($/MWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	¢/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - with PTC / ITC Credits
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 200 MWh	1500	37%	50.15	88%	0	-	10.00	0.00%	0.00	0.93	-	61.08	(6.22)	54.86
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 200 MWh	4500	30%	62.01	88%	0	-	0.00	0.00%	0.00	0.93	-	62.94	(6.22)	56.72
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 200 MWh	6500	44%	41.86	88%	0	-	0.65	0.00%	0.00	0.93	-	43.43	(6.22)	37.21
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 200 MWh	1500	37%	50.29	88%	0	-	10.00	0.00%	0.00	0.93	-	61.22	(6.22)	55.00
PV Idaho Falls, ID, 200 MW, 2021, 28.1% CF (30% ITC)	4700	28%	48.77	na	0	-	0.00	0.00%	0.00	0.70	-	49.47	(13.57)	35.90
PV Lakeview, OR, 200 MW, 2021, 29.7% CF (30% ITC)	4800	30%	48.12	na	0	-	0.00	0.00%	0.00	0.70	-	48.82	(13.43)	35.40
PV Milford, UT, 200 MW, 2021, 32.5% CF (30% ITC)	5000	33%	42.31	na	0	-	0.00	0.00%	0.00	0.70	-	43.01	(11.71)	31.31
PV Utah North, 200 MW, 2021, 30.1% CF (30% ITC)	5000	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(12.61)	33.24
PV Rock Springs, WY, 200 MW, 2021, 30.1% CF (30% ITC)	6400	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(12.61)	33.24
PV Yakima, WA, 200 MW, 2021, 26% CF (30% ITC)	1000	26%	54.89	na	0	-	0.00	0.00%	0.00	0.70	-	55.60	(15.31)	40.28
PV Idaho Falls, ID, 200 MW, 2026, 28.1% CF (10% ITC)	4700	28%	48.77	na	0	-	0.00	0.00%	0.00	0.70	-	49.47	(4.97)	44.50
PV Lakeview, OR, 200 MW, 2026, 29.7% CF (10% ITC)	4800	30%	48.12	na	0	-	0.00	0.00%	0.00	0.70	-	48.82	(4.92)	43.91
PV Milford, UT, 200 MW, 2026, 32.5% CF (10% ITC)	5000	33%	42.31	na	0	-	0.00	0.00%	0.00	0.70	-	43.01	(4.29)	38.73
PV Utah North, 200 MW, 2021, 30.1% CF (10% ITC)	5000	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(4.62)	41.23
PV Rock Springs, WY, 200 MW, 2026, 30.1% CF (10% ITC)	6400	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(4.62)	41.23
PV Yakima, WA, 200 MW, 2026, 26% CF (10% ITC)	1000	26%	54.89	na	0	-	0.00	0.00%	0.00	0.70	-	55.60	(5.61)	49.99
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (30% ITC)	4700	28%	60.55	88%	0	-	0.00	0.00%	0.00	0.70	-	61.25	(17.25)	44.01
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (30% ITC)	4800	30%	59.80	88%	0	-	0.00	0.00%	0.00	0.70	-	60.50	(17.07)	43.43
PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (30% ITC)	5000	33%	52.29	88%	0	-	0.00	0.00%	0.00	0.70	-	52.99	(14.88)	38.11
PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (30% ITC)	5000	30%	56.38	88%	0	-	0.00	0.00%	0.00	0.70	-	57.08	(16.04)	41.04
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (30% ITC)	6400	30%	56.38	88%	0	-	0.00	0.00%	0.00	0.70	-	57.08	(16.04)	41.04
PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (30% ITC)	1000	26%	68.24	88%	0	-	0.00	0.00%	0.00	0.70	-	68.95	(19.47)	49.48
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (10% ITC)	4700	28%	60.55	88%	0	-	0.00	0.00%	0.00	0.70	-	61.25	(6.32)	54.94
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (10% ITC)	4800	30%	59.80	88%	0	-	0.00	0.00%	0.00	0.70	-	60.50	(6.25)	54.25
PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (10% ITC)	5000	33%	52.29	88%	0	-	0.00	0.00%	0.00	0.70	-	52.99	(5.45)	47.54
PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (10% ITC)	5000	30%	56.38	88%	0	-	0.00	0.00%	0.00	0.70	-	57.08	(5.87)	51.21
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (10% ITC)	6400	30%	56.38	88%	0	-	0.00	0.00%	0.00	0.70	-	57.08	(5.87)	51.21
PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (10% ITC)	1000	26%	68.24	88%	0	-	0.00	0.00%	0.00	0.70	-	68.95	(7.13)	61.82
Oregon PS, 400 MW X 3,800 MWh	4457	36%	65.59	79%	*324*	27.44	0.00	0.00%	0.00	-	-	93.03	-	93.03
Oregon PS joint ownership, 100 MW X 950 MWh	4457	36%	65.68	79%	*324*	27.44	0.00	0.00%	0.00	-	-	93.12	-	93.12
Washington PS, 1,200 MW X 16,800 MWh	500	36%	56.91	79%	*320*	27.14	0.00	0.00%	0.00	-	-	84.06	-	84.06
Wyoming PS, 700 MW X 7,000 MWh	580	36%	68.79	79%	*320*	27.13	0.00	0.00%	0.00	-	-	95.92	-	95.92
Wyoming PS, 400 MW X 3,400 MWh	6000	36%	51.12	79%	*320*	27.13	0.00	0.00%	0.00	-	-	78.25	-	78.25
Utah PS, 300 MW X 1,800 MWh	6359	36%	63.65	79%	*327*	27.67	0.00	0.00%	0.00	-	-	91.31	-	91.31
Idaho PS, 360 MW X 2,880 MWh	5000	36%	57.59	79%	*327*	27.67	0.00	0.00%	0.00	-	-	85.25	-	85.25
CAES, 320 MW X 15,360 MWh	4600	72%	20.20	55%	*327*	39.74	0.00	0.00%	0.00	-	-	59.94	-	59.94
Li-Ion 15 MW X 60 MWh	0	17%	142.42	88%	*327*	24.84	15.07	0.00%	0.00	-	-	182.32	-	182.32

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Convert to $/MWh					Variable Costs ($/MWh)					Total Costs and Credits ($/MWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	¢/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - with PTC / ITC Credits
Brownfield Site														
Dave Johnston														
SCCT Frame "F" x1	5050	33%	27.81	na	327	32.11	6.61	11.48%	0.76	-	-	67.29	-	67.29
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	6400	44%	31.05	na	0	-	0.65	0.00%	0.00	0.93	-	32.63	(6.22)	26.41
CCCT Dry "J/HA.02", 1x1	5050	78%	19.34	na	320	20.66	2.05	10.21%	0.21	-	-	42.25	-	42.25
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	47.20	na	320	20.66	0.16	0.00%	0.00	-	-	68.02	-	68.02
Hunter														
SCCT Frame "F" x1	5050	33%	27.81	na	327	32.11	6.61	11.48%	0.76	-	-	67.29	-	67.29
PV, 200 MW, 2026, 32.5% CF (10% ITC)	5000	33%	42.31	na	0	-	0.00	0.00%	0.00	0.70	-	43.01	(4.29)	38.73
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	5000	33%	52.29	88%	0	-	0.00	0.00%	0.00	0.70	-	52.99	(5.45)	47.54
CCCT Dry "J/HA.02", 1x1	5050	78%	17.89	na	327	21.17	2.05	10.21%	0.21	-	-	41.31	-	41.31
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	37.77	na	327	21.17	0.16	0.00%	0.00	-	-	59.09	-	59.09
Huntington														
SCCT Frame "F" x1	5050	33%	27.81	na	327	32.11	6.61	11.48%	0.76	-	-	67.29	-	67.29
PV, 200 MW, 2026, 32.5% CF (10% ITC)	5000	33%	42.31	na	0	-	0.00	0.00%	0.00	0.70	-	43.01	(4.29)	38.73
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	5000	33%	52.29	88%	0	-	0.00	0.00%	0.00	0.70	-	52.99	(5.45)	47.54
CCCT Dry "J/HA.02", 1x1	5050	78%	17.89	na	327	21.17	2.05	10.21%	0.21	-	-	41.31	-	41.31
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	37.77	na	327	21.17	0.16	0.00%	0.00	-	-	59.09	-	59.09
Jim Bridger														
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	6400	44%	31.05	na	0	-	0.65	0.00%	0.00	0.93	-	32.63	(6.22)	26.41
Wind + Stor, 200 MW+ 50 MW | 400 MWh	6500	44%	47.19	88%	0	-	0.65	0.00%	0.00	0.93	-	48.77	(6.22)	42.55
SCCT Frame "F" x1	6500	33%	27.17	na	321	31.43	6.96	11.48%	0.80	-	-	66.36	-	66.36
PV, 200 MW, 2026, 32.5% CF (10% ITC)	6400	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(4.62)	41.23
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	6400	30%	56.38	88%	0	-	0.00	0.00%	0.00	0.70	-	57.08	(5.87)	51.21
CCCT Dry "J/HA.02", 1x1	6500	78%	18.14	na	321	21.45	2.15	10.21%	0.22	-	-	41.97	-	41.97
CCCT Dry "J/HA.02", DF, 1x1	6500	12%	34.70	na	321	21.45	0.16	0.00%	0.00	-	-	56.31	-	56.31
Naughton														
SCCT Frame "F" x1	6500	33%	28.98	na	327	32.05	6.96	11.48%	0.80	-	-	68.78	-	68.78
PV 200 MW, 2026, 30.1% CF (10% ITC)	6400	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(4.62)	41.23
CCCT Dry "J/HA.02", 1x1	6500	78%	18.66	na	327	21.88	2.15	10.21%	0.22	-	-	42.91	-	42.91
CCCT Dry "J/HA.02", DF, 1x1	6500	12%	38.08	na	327	21.88	0.16	0.00%	0.00	-	-	60.11	-	60.11
Wyodak														
SCCT Frame "F" x1	6500	33%	34.17	na	323	31.58	6.96	11.48%	0.80	-	-	73.51	-	73.51

1/ Input into IRP SO and PAR Model
2/ Wind and solar shapes are input into IRP SO and PAR Model
NC = Not Calculated
Results presented without credits
Information Presented is Illustrative

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Resources not Modeled in 2019 IRP

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Convert to $/MWh					Variable Costs ($/MWh)					Total Costs and Credits ($/MWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed ($/MWh)	Storage Efficiency	¢/mmBtu	$/MWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - with PTC / ITC Credits
SCPC with CCS	4500	90%	64.62	na	178	23.30	7.00	0.00%	0.00	-	-	94.91	-	94.91
IGCC with CCS	4500	86%	62.30	na	178	19.27	11.77	11.52%	1.36	-	-	94.69	-	94.69
PC CCS retrofit @ 500 MW	4500	90%	21.90	na	178	25.58	6.47	0.00%	0.00	-	-	53.96	-	53.96
SCPC with CCS	6500	90%	70.74	na	178	23.57	7.58	0.00%	0.00	-	-	101.89	-	101.89
IGCC with CCS	6500	86%	70.21	na	178	19.66	14.11	0.00%	0.00	-	-	103.98	-	103.98
PC CCS retrofit @ 500 MW	6500	90%	22.78	na	178	25.58	7.00	0.00%	0.00	-	-	55.36	-	55.36
Greenfield Binary 90% CF	4500	90%	59.99	na	0	-	1.16	0.00%	0.00	-	-	61.15	(15.55)	45.60
Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 100 MWh	4500	37%	46.12	88%	0	-	0.00	0.00%	0.00	0.93	-	47.05	(6.22)	40.83
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 100 MWh	1500	37%	46.72	88%	0	-	10.00	0.00%	0.00	0.93	-	57.65	(6.22)	51.42
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 100 MWh	4500	30%	57.95	88%	0	-	0.00	0.00%	0.00	0.93	-	58.87	(6.22)	52.65
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 100 MWh	6500	44%	39.10	88%	0	-	0.65	0.00%	0.00	0.93	-	40.68	(6.22)	34.46
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 100 MWh	1500	37%	46.85	88%	0	-	10.00	0.00%	0.00	0.93	-	57.78	(6.22)	51.56
Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 400 MWh	4500	37%	55.62	88%	0	-	0.00	0.00%	0.00	0.93	-	56.55	(6.22)	50.33
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 400 MWh	1500	37%	56.82	88%	0	-	10.00	0.00%	0.00	0.93	-	67.75	(6.22)	61.53
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 400 MWh	4500	30%	69.89	88%	0	-	0.00	0.00%	0.00	0.93	-	70.82	(6.22)	64.60
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 400 MWh	6500	44%	47.19	88%	0	-	0.65	0.00%	0.00	0.93	-	48.77	(6.22)	42.55
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 400 MWh	1500	37%	56.97	88%	0	-	10.00	0.00%	0.00	0.93	-	67.90	(6.22)	61.68
PV Idaho Falls, ID, 50 MW, 28.1% CF (30% ITC)	4700	28%	51.73	na	0	-	0.00	0.00%	0.00	0.70	-	52.43	(14.58)	37.86
PV Lakeview, OR, 50 MW, 2021, 29.7% CF (30% ITC)	4800	30%	50.92	na	0	-	0.00	0.00%	0.00	0.70	-	51.63	(14.38)	37.24
PV Milford, UT, 50 MW, 2021, 32.5% CF (30% ITC)	5000	33%	44.87	na	0	-	0.00	0.00%	0.00	0.70	-	45.58	(12.58)	32.99
PV Rock Springs, WY, 50 MW, 2021, 30.1% CF (30% ITC)	6400	30%	47.91	na	0	-	0.00	0.00%	0.00	0.70	-	48.62	(13.56)	35.06
PV Yakima, WA, 50 MW, 2021, 26% CF (30% ITC)	1000	26%	58.09	na	0	-	0.00	0.00%	0.00	0.70	-	58.80	(16.40)	42.39
PV Idaho Falls, ID, 50 MW, 2026, 28.1% CF (10% ITC)	4700	28%	51.73	na	0	-	0.00	0.00%	0.00	0.70	-	52.43	(5.34)	47.09
PV Lakeview, OR, 50 MW, 2026, 29.7% CF (10% ITC)	4800	30%	50.92	na	0	-	0.00	0.00%	0.00	0.70	-	51.63	(5.27)	46.36
PV Milford, UT, 50 MW, 2026, 32.5% CF (10% ITC)	5000	33%	44.87	na	0	-	0.00	0.00%	0.00	0.70	-	45.58	(4.61)	40.97
PV Rock Springs, WY, 50 MW, 2026, 30.1% CF (10% ITC)	6400	30%	47.91	na	0	-	0.00	0.00%	0.00	0.70	-	48.62	(4.96)	43.65
PV Yakima, WA, 50 MW, 2026, 26% CF (10% ITC)	1000	26%	58.09	na	0	-	0.00	0.00%	0.00	0.70	-	58.80	(6.01)	52.79
PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 20 MWh (30% ITC)	4700	28%	60.68	88%	0	-	0.00	0.00%	0.00	0.70	-	61.39	(18.53)	42.85
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 100 MWh (30% ITC)	4700	28%	55.48	88%	0	-	0.00	0.00%	0.00	0.70	-	56.18	(17.25)	38.93
PV + Stor,, Idaho Falls, ID, 50 MW + 10 MW X 40 MWh (30% ITC)	4700	28%	65.34	88%	0	-	0.00	0.00%	0.00	0.70	-	66.04	(18.53)	47.51
PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 80 MWh (30% ITC)	4700	28%	73.32	88%	0	-	0.00	0.00%	0.00	0.70	-	74.03	(18.53)	55.50
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 400 MWh (30% ITC)	4700	28%	69.88	88%	0	-	0.00	0.00%	0.00	0.70	-	70.58	(17.25)	53.34
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 20 MWh (30% ITC)	4800	30%	59.72	88%	0	-	0.00	0.00%	0.00	0.70	-	60.42	(18.28)	42.14
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 100 MWh (30% ITC)	4800	30%	54.67	88%	0	-	0.00	0.00%	0.00	0.70	-	55.37	(17.07)	38.30
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 40 MWh (30% ITC)	4800	30%	64.42	88%	0	-	0.00	0.00%	0.00	0.70	-	65.12	(18.28)	46.84
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 80 MWh (30% ITC)	4800	30%	72.51	88%	0	-	0.00	0.00%	0.00	0.70	-	73.22	(18.28)	54.93
PV + Stor,, Lakeview, OR, 200 MW + 50 MW X 400 MWh (30% ITC)	4800	30%	69.27	88%	0	-	0.00	0.00%	0.00	0.70	-	69.98	(17.07)	52.91
PV + Stor,, Milford, UT, 50 MW + 10 MW X 20 MWh (30% ITC)	5000	33%	52.40	88%	0	-	0.00	0.00%	0.00	0.70	-	53.10	(15.99)	37.11
PV + Stor,, Milford, UT, 200 MW + 50 MW X 100 MWh (30% ITC)	5000	33%	47.90	88%	0	-	0.00	0.00%	0.00	0.70	-	48.60	(14.88)	33.72
PV + Stor,, Milford, UT 50 MW + 10 MW X 40 MWh (30% ITC)	5000	33%	56.43	88%	0	-	0.00	0.00%	0.00	0.70	-	57.13	(15.99)	41.14
PV + Stor,, Milford, UT, 50 MW + 10 MW X 80 MWh (30% ITC)	5000	33%	63.33	88%	0	-	0.00	0.00%	0.00	0.70	-	64.03	(15.99)	48.04
PV + Stor,, Milford, UT, 200 MW + 50 MW X 400 MWh (30% ITC)	5000	33%	60.35	88%	0	-	0.00	0.00%	0.00	0.70	-	61.06	(14.88)	46.17
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 20 MWh (30% ITC)	6400	30%	56.50	88%	0	-	0.00	0.00%	0.00	0.70	-	57.20	(17.23)	39.97
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 100 MWh (30% ITC)	6400	30%	51.64	88%	0	-	0.00	0.00%	0.00	0.70	-	52.34	(16.04)	36.31
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 40 MWh (30% ITC)	6400	30%	60.85	88%	0	-	0.00	0.00%	0.00	0.70	-	61.55	(17.23)	44.31
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 80 MWh (30% ITC)	6400	30%	68.30	88%	0	-	0.00	0.00%	0.00	0.70	-	69.00	(17.23)	51.77
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 400 MWh (30% ITC)	6400	30%	65.09	88%	0	-	0.00	0.00%	0.00	0.70	-	65.79	(16.04)	49.75
PV + Stor,, Yakima, WA, 50 MW + 10 MW X 20 MWh (30% ITC)	1000	26%	68.15	88%	0	-	0.00	0.00%	0.00	0.70	-	68.85	(20.85)	48.00
PV + Stor, Yakima, WA, 200 MW + 50 MW X 100 MWh (30% ITC)	1000	26%	62.38	88%	0	-	0.00	0.00%	0.00	0.70	-	63.08	(19.47)	43.62
PV + Stor, Yakima, WA, 50 MW + 10 MW X 40 MWh (30% ITC)	1000	26%	73.52	88%	0	-	0.00	0.00%	0.00	0.70	-	74.22	(20.85)	53.37
PV + Stor, Yakima, WA, 50 MW + 10 MW X 80 MWh (30% ITC)	1000	26%	82.77	88%	0	-	0.00	0.00%	0.00	0.70	-	83.48	(20.85)	62.62
PV + Stor, Yakima, WA, 200 MW + 50 MW X 400 MWh (30% ITC)	1000	26%	79.07	88%	0	-	0.00	0.00%	0.00	0.70	-	79.78	(19.47)	60.31
Li-Ion 1 MW X 250 kWh	0	1%	1,886.99	88%	327	24.84	11.42	0.00%	0.00	-	-	1,923.24	-	1,923.24
Li-Ion 1 MW X 2 MWh	0	8%	430.85	88%	327	24.84	15.70	0.00%	0.00	-	-	471.38	-	471.38
Li-Ion 1 MW X 4 MWh	0	17%	284.12	88%	327	24.84	14.98	0.00%	0.00	-	-	323.94	-	323.94
Li-Ion 1 MW X 8 MWh	0	33%	225.69	88%	327	24.84	14.98	0.00%	0.00	-	-	265.50	-	265.50
Flow 1 MW X 6 MWh	0	25%	217.62	65%	327	33.62	0.00	0.00%	0.00	-	-	251.24	-	251.24
Advanced Fission	5000	86%	74.25	na	0	-	11.75	0.00%	0.00	-	-	86.00	-	86.00
Small Modular Reactor x 12	5000	86%	79.12	na	0	-	15.50	0.00%	0.00	-	-	94.62	-	94.62

Additionally, total resource costs were prepared for three natural gas-fired combined cycle combustion turbine resource options at an elevation of 5,050 feet at varying capacity factors to show how these costs are affected by dispatch. Table 6.3 shows the total resource cost results for this analysis.

Table 6.3 - Total Resource Cost, for various Capacity Factors ($/MWh, 2018$)

Total Resource Cost ($/MWh)			
Capacity Factor CCCT	**40%**	**78%**	**94%**
Capacity Factor Duct Fire	**10%**	**12%**	**22%**
CCCT Dry "G/H", 1x1	$68.15	$46.45	$42.56
CCCT Dry "G/H", DF, 1x1	$75.94	$66.85	$46.20
CCCT Dry "G/H", 2x1	$56.24	$40.30	$37.45
CCCT Dry "G/H", DF, 2x1	$66.11	$58.66	$41.75
CCCT Dry "J/HA.02", 1x1	$61.02	$42.68	$39.39
CCCT Dry "J/HA.02", DF, 1x1	$69.63	$61.57	$43.25
CCCT Dry, "J/HA.02" 2X1	$51.14	$37.57	$35.14
CCCT Dry "J/HA.02", DF, 2X1	$61.64	$54.91	$39.63

Table 6.4 - Glossary of Terms from the SSR

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).

Term	Description
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.
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.
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 6.5 - Glossary of Acronyms Used in the Supply-Side Resources

Acronyms	Description
AFSL	Average Feet (Above) Sea Level
CAES	Compressed Air Energy Storage
CCCT	Combined Cycle Combustion Turbine
CCS	Carbon Capture and Sequestration
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
NCM	Nickel Cobalt Manganese (sub-chemistry of Li-Ion)
PPA	Power Purchase Agreement
PC CCS	Pulverized Coal equipped with Carbon Capture and Sequestration
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
SCPC	Super-Critical Pulverized Coal

Resource Option Descriptions

The following are brief descriptions of each of the resources listed in Table 6.1.

Natural Gas, Simple Combined Cycle Turbine (SCCT) Aero x 3 – a resource based on three General Electric LM6000PF-Sprint 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, Intercooled SCCT Aero x 2 – a resource based on two General Electric LMS100PA+ simple cycle aero-derivative intercooled combustion turbine fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. An air-cooled intercooler is assumed.

Natural Gas, SCCT Frame "F" x 1 – a resource based on one General Electric 7FA.05 simple cycle frame type combustion turbine fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions.

Natural Gas, Internal Combustion (IC) Recips x 6 – a resource based on six Wartsila 18V50SG reciprocating engines fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions.

Natural Gas, Combined Cycle Combustion Turbine (CCCT) Dry "G/H", 1x1 – a combined cycle resource based on one frame-type General Electric 7HA.01 combustion turbine, 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.

Natural Gas, CCCT Dry "G/H", DF, 1x1 – an option that can be added to a combined cycle plant to increase its capacity by the addition of duct burners in the heat recovery steam generator. This increases the amount of steam generated in the heat recovery steam generator. The amount of duct firing is up to the owner. Depending on the amount of duct firing added, the size of the steam turbine, steam turbine generator and associated feed water, steam condensing and cooling systems may need to be increased. This description also applies to the following technologies that are listed on Table 6.1: CCCT Dry "G/H", DF, 2x1; CCCT Dry "J/HA.02", DF, 1x1; CCCT Dry "J/HA.02", DF, 2x1.

Natural Gas, CCCT Dry "G/H", 2x1 - a combined cycle resource based on two frame-type General Electric 7HA.01 combustion turbines, two 3-pressure heat recovery steam generators 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.

Natural Gas, CCCT Dry "J/HA.02", 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.

Natural Gas, CCCT Dry "J/HA.02", 2x1 - a combined cycle resource based on two frame-type Mitsubishi M501GAC combustion turbines (air-cooled), two 3-pressure heat recovery steam generators 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, Super-critical Pulverized Coal (SCPC) with Carbon Capture and Sequestration (CCS) – conventional coal-fired generation resource including a supercritical boiler (up to 4000 psig) using pulverized coal with all emission controls including scrubber, fabric filters (baghouse), mercury control, selective catalytic reduction (SCR) and CCS to reduce carbon dioxide emissions by 90 percent.

Coal, PC CCS retrofit at 500 MW – a retrofit of an existing conventional coal-fired boiler and steam turbine resource. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output and would remove carbon dioxide by 90 percent and provide a marginal improvement in other emissions.

Coal, IGCC with CCS – an advanced IGCC resource to facilitate lower cost carbon capture and sequestration costs. An IGCC plant produces a synthetic fuel gas from coal using an advanced oxygen blown gasifier and burning the synthetic fuel gas in a conventional combustion turbine combined cycle power facility. The IGCC would utilize the latest advanced combustion turbine technology and provide fuel gas cleanup to achieve ultra-low emissions of sulfur dioxide, nitrogen oxides using selective catalytic reduction systems, mercury and particulate. Carbon dioxide would be removed from the synthetic fuel gas before combustion thereby reducing carbon dioxide emissions by more than 90 percent.

Wind, 3.6 MW turbine 37 percent NCF WA/OR/ID – a wind resource based on 3.6 MW wind turbines located in Washington, Oregon or Idaho with an estimated annual net capacity factor of 37 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Wind, 3.6 MW turbine 29 percent Net Capacity Factor (NCF) UT – a wind resource based on 3.6 MW wind turbines located in Utah with an estimated annual net capacity factor of 29 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Wind, 3.6 MW turbine 43 percent NCF WY – a wind resource based on 3.6 MW wind turbines located in Wyoming with an estimated annual net capacity factor of 43 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Solar, PV Single Axis Tracking in ID, OR, UT, WA, and WY with NCF between 26.0 and 32.5 percent depending upon location (1.46 MWdc/MWac) – a large utility scale (50 MW or 200 MW) solar photovoltaic resource using crystalline silica solar panels in a single axis tracking system located in southwestern Utah.

Storage, Pumped Hydro Storage – a range (400 - 1,200 MW) of pumped storage systems using a combination of natural and constructed water storage combined with elevation difference to

enable a system capable of discharging the rated capacity for eight hours combined with recharging that capacity over 16 hours. Total development time is estimated at six-to-12 years due to various progress on permitting. The recharge ratio for this resource is 79 percent. Actual pumped hydro storage projects within PacifiCorp's territory were analyzed.

Storage, Lithium Ion Battery – a battery technology of lithium ion batteries located close to the load center. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year. The recharge ratio for this storage resource is 88 percent.

Storage, Flow Battery – a battery technology based vanadium ReDOx or other flow battery types. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year. The recharge ratio for this storage resource is 65 percent.

Storage, CAES – compressed air energy storage (CAES) system consists of air storage reservoir replacing the compressor on a conventional gas turbine. The gas turbine exhaust powers a power turbine providing a simple cycle gas turbine energy at lower costs than a conventional gas turbine. Off-peak energy is used to compress air into the storage reservoir. A system size of 320 MW is assumed. The air storage reservoir is assumed to be solution mined to size. Natural gas is required to generate power. Although the recharge ratio is difficult to separate from the fuel combustion a recharge ratio assumed for this storage resource is 55 percent which includes the fuel required during the power generation cycle.

Nuclear, Advanced Fission – a large 2,234 MW nuclear resource reflects the current state-of-the-art advanced nuclear plant and is modeled after the Westinghouse AP1000 technology. The assumed location for this resource is the proposed Blue Castle site near Green River, Utah which is in development. It is expected that the resource would not be available earlier than 2025.

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 570 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 10 years for availability.

Resource Types

Renewables

PacifiCorp retained Burns & McDonnell Engineering Company (BMcD) to evaluate various renewable energy resources in support of the development of the 2019 IRP and associated resource acquisition portfolios and/or products. The 2018 Renewable Resources Assessment and Summary Tables (Assessment) (See Volume II, Appendix P) 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 to further investigate each technology and its direct application within the owner's long-term plans.

- Single Axis Tracking Solar
- Onshore Wind
- Energy Storage
    - Pumped hydro energy storage (PHES)

    - CAES
    - Li-Ion Battery
    - Flow Battery
- Solar + Energy Storage
- Wind + 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 the PacifiCorp:

- AFUDC
- Escalation
- Sales tax
- Property taxes and insurance
- Utility demand costs

Solar
The BMcD Assessment includes 5 MW, 50 MW, and 200 MW single axis tracking (SAT), PV options evaluated at five locations within the PacifiCorp services area. The 2019 differs from previous IRP's in the following ways:

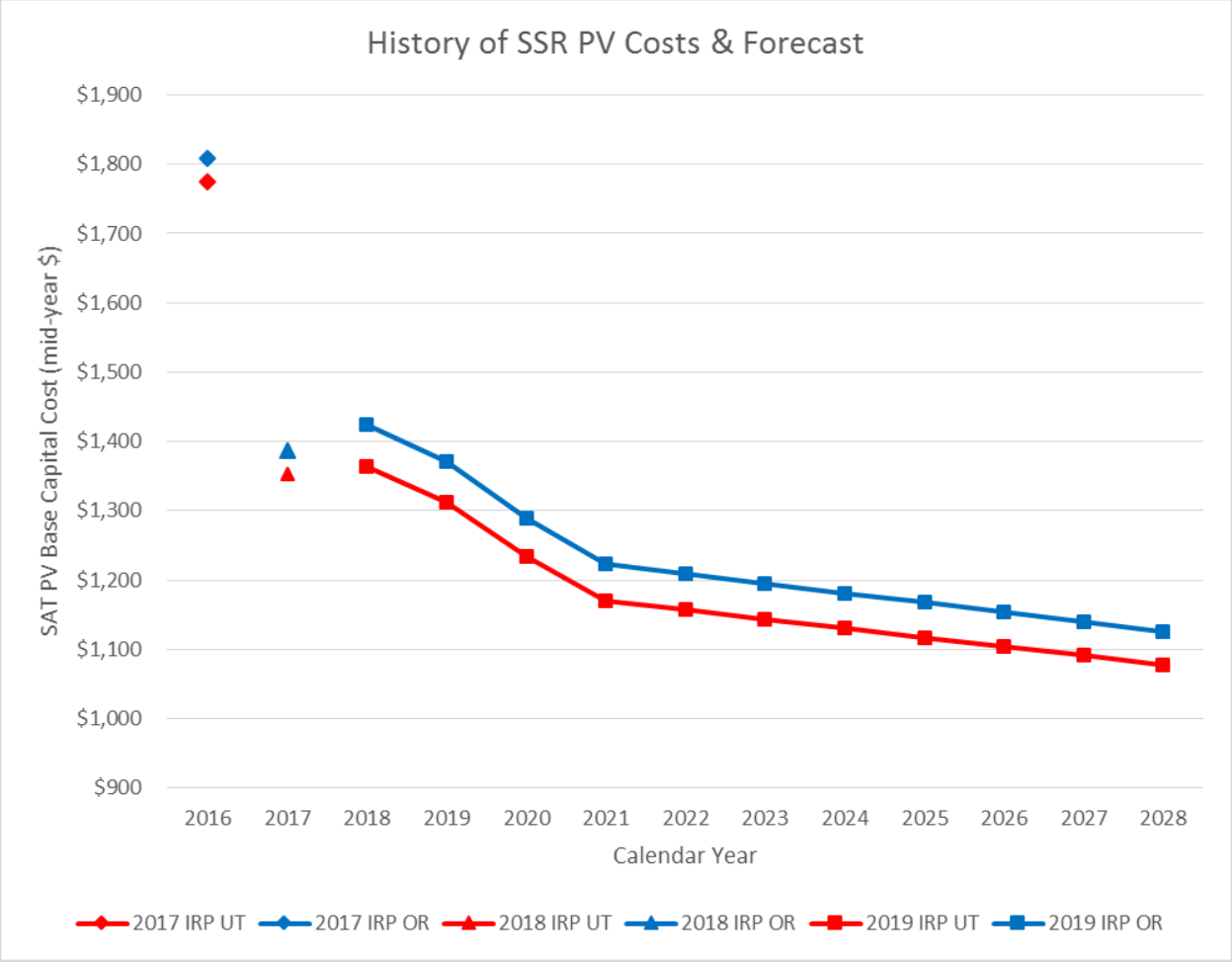
- The number of locations for solar development were expanded from two states (OR & UT) to five states (ID, OR, UT, WA, and WY) to reflect expanding solar development activity within PacifiCorp's service territory.
- A 200 MW option was added for each of the five locations based upon industry trends of building larger solar facilities.
- Fixed tilt PV and concentrated solar are not included based to findings in the 2017 IRP that SAT PV resources have lower costs and are better suited to PacifiCorp's service territory than fixed tilt PV or concentrated solar systems for the system sizes considered.

Solar costs (including forecasted costs) used for the 2019 IRP are higher than those used in the 2017 IRP Update, but are significantly lower than those used in the 2017 IRP. The increase from the 2017 IRP Update is partially due to a different assumed design. The inverter loading ratio results in a higher base capital cost, but a lower levelized cost of energy (LCOE). In addition to the different design basis two significant events have occurred with respect to solar costs since the 2017 IRP.

In late September 2017 the International Trade Commission passed a finding of injury to US solar manufacturers. A significant increase in solar prices in the US occurred following the ITC ruling. Solar costs have since resumed a declining trend, though at a reduced rate of decline. On January 22, 2018, the United States levied a 30 percent tariff on solar imports. The tariff covers both imported solar cells and solar modules. The tariff is expected to last for four years falling by five percent annually, dropping to a 15 percent tariff in 2021. At the time the tariff was levied solar prices briefly halted their decline from the peak price which occurred after the ITC ruling. Figure

6.4 shows a history of capital costs and a forecast used in the SSR for PV resources in Utah and Oregon. The forecast data for the solar 2019 IRP PV costs were provided via NREL data on an annual basis. The decreasing slope starting in 2021 shows that NREL is expecting storage pricing to drop more over the next three years than the years after that.

Figure 6.4 – History of SSR PV Cost & Forecast



There was significant solar development activity in PacifiCorp's service territory between 2012 and 2018. Over the course of those seven years, 332 solar projects with nameplates of 10 MW or greater have initiated generation interconnection requests with PacifiCorp. The total nameplate capacity of those 330 projects is over 27,500 MW. There were 66 new renewable generation projects greater than 10 MW that entered PacifiCorp's generation interconnection queue during 2018; of these 67 new projects, 51 are solar, six are solar & battery storage, seven are wind, one is battery energy storage, and one is nuclear. The nameplate capacity of the 57 solar projects added in 2018 alone is over 7,300 MW. While many projects that have initiated generation interconnection studies over the past 17 years have not been built, the number and size of the 2018 interconnection solar projects is testament to the tremendous solar development activity that is underway within PacifiCorp's service territory.

Wind

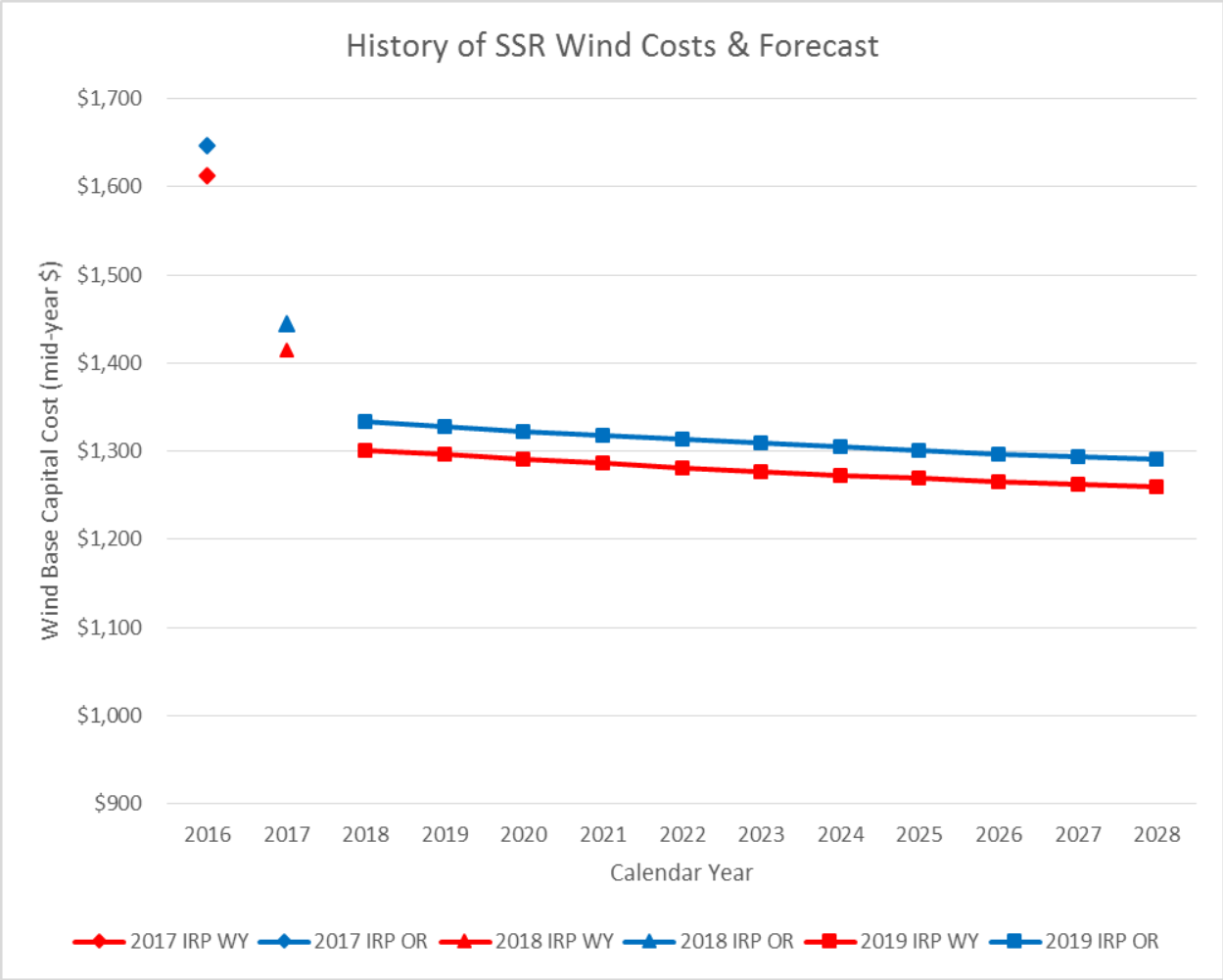
The 2017 IRP found wind energy to be one of the most cost effective new generation resources for PacifiCorp's customers and led to PacifiCorp's Energy Vision 2020 initiative. Energy Vision 2020 includes three new wind projects, a new 500-kV transmission line, and upgrades to existing

infrastructure to deliver the new wind generation to PacifiCorp's customers. The three new wind projects will add 1,150 MW of new wind power to PacifiCorp's generation resources. Wind capital costs in the 2019 IRP are lower than the cost estimates in the 2017 IRP and will push the LCOE for new projects lower. However, reductions in federal production tax credits (PTCs) will push the LCOE for new wind projects built after 2020 higher, assuming there are no changes to PTC policy.

The BMcD Assessment includes 200 MW onshore wind generating facilities in the states of Idaho, Oregon, Utah, Washington, and Wyoming to reflect strong wind resources available within or near PacifiCorp's service areas. BMcD relied on publicly available data and proprietary computational programs to complete the net capacity factor characterization. Generic project locations were selected by the company based on viable wind project locations where there are favorable wind profiles. Figure 6.5 shows a history of capital costs and a forecast used in the SSR for wind resources in Wyoming and Oregon. Utility scale wind farm costs have declined significantly in recent years on a per MW nameplate basis due in large part to substantial increases in the MW size of wind turbines on the market.

Federal PTCs were extended in December 2015 and included a graduated phase out structure that reduces the value of the credits for projects completed after 2021 and eliminates PTCs completely for projects completed after 2023. The PTC extension has led to increasing demand for safe harbor and follow-on wind turbine generators (WTGs) in the United States since 2016 as developers and owners have chosen to purchase safe harbor equipment between 2016 and 2019 to qualify projects that will be commercially operational no later than 2020 to 2023. Burns & McDonnell estimates the cost of wind projects will remain mostly flat with cost decreases of less than five percent over the next ten years, while other estimates indicate the LCOE for wind production could decline as much as 20 percent over the next ten years. While the wind industry has faced PTC cliffs in the past, it is difficult to predict how the scheduled phase out of PTC benefits will impact the cost of future wind projects in the market over the next five to ten years.

Figure 6.5 – History of SSR Wind Costs & Forecast



Capital Costs

Capital cost estimates for wind resources in the IRP are based upon a combination of the Burns & McDonnell study, communications with wind equipment and construction companies, and PacifiCorp's active wind construction projects. All wind resources are specified in 200 MW blocks, but the model can choose multiple blocks or a fractional amount of a block.

Wind Resource Capacity Factors and Energy Shapes

Resource options in the topology bubbles are assigned capacity factors based upon historic or expected project performance. Assigned capacity factor values for wind resources are 43 percent in Wyoming, 37 percent in Washington, Oregon and Idaho, and 29 percent in Utah. Capacity factor is a separate modeled parameter from the capital cost, and is used to scale wind energy shapes used by both the SO model and the Planning and Risk model (PaR). The hourly generation shape reflects average hourly wind variability. The hourly generation shape is repeated for each year of the simulation.

Wind Integration Costs

To capture the costs of integrating wind into the system, PacifiCorp applied a value of $1.11/MWh (in 2018 dollars) for resource selection. To capture the costs of integrating solar into the system, PacifiCorp applied a value of $0.85/MWh (in 2018 dollars). Additional detailed information can be found in PacifiCorp's 2019 flexible reserve study (Volume II, Appendix F). Integration costs

were incorporated into wind capital costs based on a 30-year project life expectancy and generation performance, and into solar capital costs based on a 25-year life expectancy and generation performance.

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 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 to 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 capital costs in the 2019 supply side resource option are built on the understanding gained from these earlier reports, publically available capital costs from the Geothermal Resources Council and publicly available prices for energy supplied under power purchase agreements.

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 close 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.

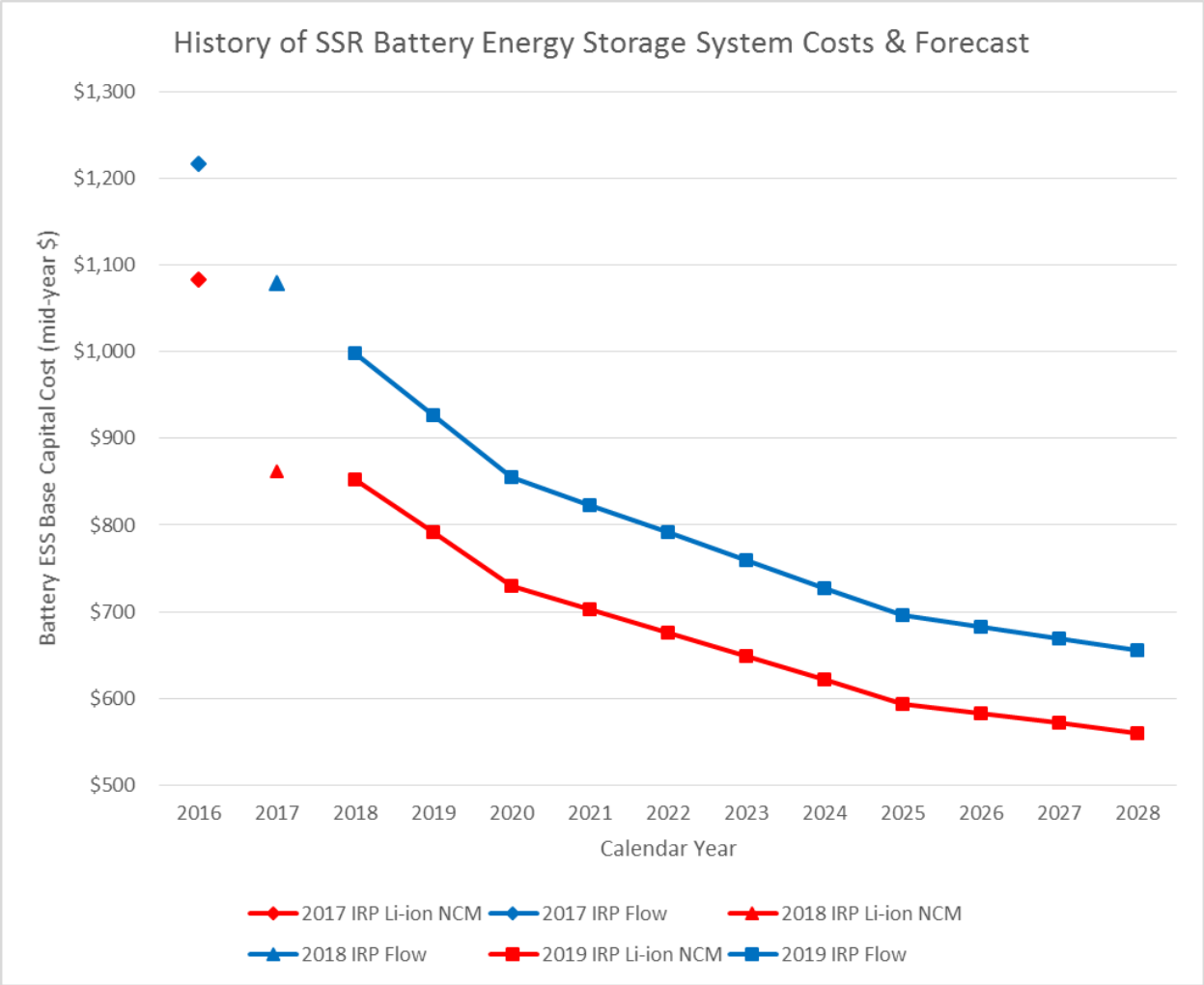
To mitigate the financial risks of geothermal development, PacifiCorp would use an RFP process to obtain market proposals for geothermal power purchase agreements or build-own-transfer project agreement structures. Geothermal developers, external to PacifiCorp, have the flexibility to structure project 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 as a new PacifiCorp generation source. 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 BMcD Assessment discusses three energy storage resource options: 1) PHES), 2) CAES, and 3) battery storage. Battery storage was also considered in combination with solar and wind. The addition of wind plus storage and solar plus storage created a large number of new resource options in the SSR. To mitigate the impact of the additional information less emphasis was placed on the various battery chemistries. Two of the three pumped hydro projects included in both the 2017 and 2019 IRP's showed modest capital cost declines while one showed a modest cost increase. The capital cost for CAES showed a 24 percent cost decrease. No forecasts have been used for pumped hydro and CAES. Both technologies are expected to have a flat forecast despite the recent movement in costs. Figure 6.6 shows a history of capital costs and a forecast used in the SSR for Li-Ion and flow battery resources. Battery costs are expected to continue to decline for the next ten years. Due to the complexity and maturity of the battery market, O&M costs continue to be an area of some uncertainty. PacifiCorp currently has two battery projects under development, one in Utah and one in Oregon, which will provide real market data to validate or indicate if an adjustment is needed for O&M costs.

Figure 6.6 – History of SSR Battery Energy Storage System Costs & Forecast



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 peaking, intermediate and base generation.

A variety of natural gas-fueled generating resources that are and will continue to be available for a several years 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. Natural gas resources generate cost competitive power while producing low air emissions. Natural gas-fueled resources are proven to be highly reliable and safe. 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 ISO conditions (zero feet above mean sea level and 59 °F) as a reference. The essential services provided by the resource are peaking, intermediate and base generation.

Three simple cycle combustion turbine options and one reciprocating engine option were offered to 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.

Options for peaking resources included in the supply side resources are: 1) three each General Electric (GE) LM6000 PF aero-derivative simple cycle combustion turbines, 2) two each GE LMS 100PA+ aero-derivative simple cycle combustion turbines, 3) one each GE 7F frame simple cycle combustion turbine, and 4) six each Wasilla 18V50SG reciprocating internal combustion engines. All of these options are highly flexible and efficient. Higher heating value heat rates for the resource ranged from 9,204 Btu/kW-hr for the LM6000 PF to 8,279 Btu/kW-hr for the 18V50SG engines. Installation of high temperature oxidation catalysts for carbon monoxide (CO) control and an SCR system for NOx control would be available for these resources.

Eight combined cycle combustion turbine options were provided for intermediate and base generating service. Intermediate generating service requires resources that are able to 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 cost effective means of providing power demand that is greater than base load and lower than peak demands. Base generating service requires a highly cost effective that is capable of operating at full production for long periods of time. Base generation provides for the minimum level of power demand over a day or longer period of time at a very low cost.

Options for intermediate and base generation were based on two size classes of engines. The “G/H” size was represented by a GE HA.01. The “J/HA.02” was represented by the GE HA.02. Each engine was arranged in a one combustion turbine to one steam turbine (1x1) and a two combustion turbine to one steam turbine (2x1) configuration to obtain four resource options. The combined cycle resources offered high heating value heat rates from 6,317 to 6,374 Btu/kW-hr. Installation of oxidation catalysts for carbon monoxide (CO) control and SCR systems for nitrogen oxides

(NOx) control is expected. All of 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 Supply Side Resource table. Duct firing is not a stand-alone resource option, but is considered to be an available option for any combined cycle configuration and represents a low cost option to add peaking capability at relatively high efficiency and also a mechanism to recover lost power generation capability at high ambient temperatures. Duct firing is shown in the Supply Side Resource table as a fixed value for each combined cycle combination. In practice the amount of duct firing is a design consideration which is selected during the development of combined cycle generating facilities.

While equipment provided by specific manufacturers were used to for cost and performance information in the supply side resource table, more than one manufacturer produces these type 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.

New natural gas resources were assumed to be installed at green-field sites on either the east or west side of PacifiCorp's system. Greenfield development includes the costs of high pressure natural gas laterals, electrical power transmission lines, ambient air monitoring, permitting, real estate, rights of way and water rights. Resources additions a brownfield site, such as an existing coal-fueled generating facility, are reduced to reflect the decreases costs.

Coal

Potential coal resources are shown in the SSR as supercritical pulverized coal (PC) boilers and IGCC, located in both Utah and Wyoming. Both resource types include carbon dioxide capture and compression needed for sequestration.

Supercritical technology is considered the standard design technology compared to subcritical technology for pulverized coal. Increasing coal costs make the added efficiency of the supercritical technology more cost-effective. Additionally, there is a greater competitive marketplace for large supercritical boilers than for large subcritical boilers. Increasingly, large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. Due to the increased efficiency of supercritical boilers, overall emission intensity rates are smaller than for similarly sized subcritical units. Compared to subcritical boilers, supercritical boilers also have better load following capability, faster ramp rates, use less water and require less steel for construction. The costs shown in the SSR for a supercritical PC facility reflect the cost of adding a new unit at an existing site.

Carbon Capture

The requirement for CO_2 CCS represents a significant cost for both new and existing coal resources. In order for a coal-fueled generating facility to meet the Federal New Source Performance Standards for Greenhouse Gases (NSPS-GHG) carbon dioxide emissions limit of 1,100 lbs per megawatt-hour would require CO_2 capture and permanent sequestration.[1] Capital

[1] This limit is still in effect and applies as it relates carbon capture analysis for the 2019 IRP. It should also be noted that on December 2018, EPA proposed revisions to the NSPS for GHG. Under the proposed rule, newly constructed plant CO_2 limits will be based on the most efficient demonstrated steam cycle in combination with the best operating practices. For large units, the BSER is proposed to be super-critical steam conditions, and if revised the emission rate would be 1,900 pounds of CO_2 per megawatt-hour on a gross output basis. For large units, the BSER

costs do not include the 45Q tax credit for carbon dioxide sequestration or enhanced oil recovery. Based on this requirement, only coal resource options that include carbon capture are included in the SSR.

Two major utility-scale CCS retrofit projects have been recently constructed and have entered commercial operation on pulverized coal plants in North America. SaskPower's 115 MW (net) $1.24 billion Boundary Dam project entered commercial operation in October 2014. In July 2016, the plant reached a major milestone when it demonstrated that over 1,100,000 tons of CO_2 had been captured. In January 2017, NRG's Petra Nova project went into commercial operation. Both of these projects have CO_2 capture rates in excess of 90 percent; sequestration is accomplished through enhanced oil recovery (EOR). Both of these projects utilize amine-based systems for carbon dioxide capture.

The Petra Nova project is especially meaningful in that the project entailed a retrofit of an existing coal-fueled plant using amine based system and captures approximately 5,000 tons per day from the 240 MWh equivalent flue gas slipstream from NRG's W.A. Parish unit 8. Captured CO_2 is 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 retrofit of a carbon capture technology of a pulverized coal plant in the world. Petra Nova is 50-50 joint venture by NRG and JX Nippon. The United States DOE is provided up to $190 million in grants as part of the Clean Coal Power Initiative Program (CCPI), a cost-shared collaboration between the federal government and private industry. The amine-based capture system utilizes Mitsubishi's proprietary KM CDR Process® and uses its KS-1™ amine solvent.

PacifiCorp continues to monitor CO_2 capture technologies for possible retrofit application on its existing coal-fired resources, as well as their applicability for future fossil fueled plants that could serve as cost-effective alternatives to IGCC plants. An option to capture CO_2 at an existing coal-fired unit has been included in the SSR. Currently there are only a limited number of large-scale sequestration projects in operation around the world; most of these have been installed in conjunction with enhanced oil recovery. Given the high capital cost of implementing CCS on coal fired generation (either on a retrofit basis or for new resources) CCS is not considered a viable option before 2025. Factors contributing to this position include capital cost risk uncertainty, the availability of commercial sequestration (non-EOR) sites, uncertainty regarding long term liabilities for underground sequestration, and the availability of federal funding to support such projects.

To address the availability of commercial sequestration, three PacifiCorp power plants participated in federally funded research to conduct a Phase I pre-feasibility study of carbon capture and storage. A grant from the U.S. DOE to the University of Wyoming was used to assess the storage of carbon dioxide in the Rock Springs Uplift, a geologic formation located 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 of projects showed that geological formations exist near the plants that may support carbon sequestration, though further study would be required. Neither site was selected by the U.S. DOE for advance study in the Phase II of the grant program.

is proposed to be subcritical conditions, and if revised the emission rate would be 2,200 pounds of CO_2 per megawatt-hour regardless of the size of the unit.

PacifiCorp issued a request for expression of interest to potential carbon capture, utilization, and storage (CCUS) counterparties on September 7, 2018. The request focused on possible deployment of CCUS technologies at PacifiCorp's Dave Johnston generating facility for potential enhanced oil recovery (EOR). On February 28, 2019, a phase I feasibility study was received by each of the three interested parties selected to participate (Jupiter Oxygen, ION Clean Energy [previously Eco2Source], and Glenrock Energy). On April 23, 2019, the participants were notified they may progress to phase II engagement of front-end engineering design (FEED) study at their discretion. None of the participants received DOE grant funds to support their FEED studies. PacifiCorp remains open to a CCUS project with the three parties if they secure funding in their own efforts.

An alternative to supercritical pulverized-coal technology for coal-based generation is the application of IGCC technology. A significant advantage for IGCC when compared to pulverized coal with amine-based carbon capture, is the reduced cost of capturing CO_2 from the process. Only a limited number of IGCC plants have been built and operated around the world. In the United States, these facilities have been demonstration projects, resulting in capital and operating costs that are significantly greater than those costs for conventional coal plants. These projects have been constructed with significant federal funding. One large, utility-scale IGCC plant with carbon capture capability recently went into service. Southern Company's 582 MW (net) $6.8 billion Kemper County project includes carbon capture (65 percent capture) and sequestration (for EOR). The plant produced electric power using syngas in October of 2016. Leaks caused the plant to miss the scheduled March 2017 completion date. Kemper power plant suspended coal gasification in June 2017.

The costs presented in the SSR for new IGCC resources are based on 2007 studies of IGCC costs associated with efforts to partner PacifiCorp with the Wyoming Infrastructure Authority (WIA) to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

A consortium of Japanese firms received orders on December 1, 2016 for two 540 MW IGCC plants to be constructed in Japan based on Mitsubishi's IGCC technology that was tested at the Nakoso Power Station from 2007 through 2013. A number of countries, including China, Turkey, Dubai, India, Kenya, Philippines, South Korea, Japan, and Malaysia have also announced plans to construct new conventional coal-fueled electric generating resources which will be monitored from a cost and technology deployment perspective.

No new cost studies were performed for coal-fueled generation options in 2018. Updated capital and O&M costs for coal-fuel generation options were based on escalating costs used in the 2017 IRP.

Coal Plant Efficiency Improvements

Fuel efficiency gains for existing coal plants, which are manifested as lower plant heat rates, are realized by: (1) continuous operations improvement, (2) monitoring the quality of the fuel supply, and (3) upgrading components if economically justified. Efficiency improvements can result in a smaller emissions footprint for a given level of plant capacity, or the same footprint when plant capacity is increased.

The efficiency of generating units, primarily measured by the heat rate (the ratio of heat input to energy output) degrades gradually as components wear over time. During operation, controllable process parameters are adjusted to optimize the unit's power output compared to its heat input. Typical overhaul work that contributes to improved efficiency includes (1) major equipment

overhauls of the steam generating equipment and combustion/steam turbine generators, (2) overhauls of the cooling systems and (3) overhauls of the pollution control equipment.

When economically justified, efficiency improvements are obtained through major component upgrades of the electricity generating equipment. The most notable examples of upgrades resulting in greater generating capacity are steam turbine upgrades. Turbine upgrades can consist of adding additional rows of blades to the rearward section of the turbine shaft (generically known as a "dense pack" configuration), but can also include replacing existing blades, replacing end seals, and enhancing seal packing media. Currently PacifiCorp has no plans to make any major steam turbine or generator upgrades over the next 10 years.

Nuclear

PacifiCorp revisited two of the nuclear options presented in the 2017 for the 2019 IRP: 1) the AP 1000 plant being developed by Blue Castle Holdings in Green River, Utah rated at 2,234 MW and 2) the 570 MW NuScale Small Modular Reactor (SMR) being developed for construction at the Idaho National Lab site. Blue Castle Holdings (BCH) did not provide updated pricing, therefore costs were escalated by two years from the costs used in the 2017 IRP. NuScale provided an update on their design, licensing and costs. NuScale's update resulted in a significant decline in the capital cost number for the Small Modular Reactor (SMR) resource option.

In 2016 BCH provided a detailed cost analysis of the Vogtle plant construction and eliminated unexpected costs which would not apply to the Green River site such as geotechnical problems encountered at the Vogtle site. The Vogtle plant was a first of a kind (FOAK) plant but the Green River plant would be an Nth of a kind (NOAK) plant based on the Vogtle plant AP 1000 design. PacifiCorp added a 3.7 percent delay cost to BCH's capital cost estimate for potential unforeseen problems not encountered on the Vogtle project. Details of the BCH project can be found at www.bluecastleproject.com.

NuScale is developing an advanced reactor design in the SMR category. Although it is an FOAK technology, the design has inherent safety features which support reduced capital costs and operating cost estimates. PacifiCorp has 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 added five percent contingency and ten percent delay costs due to the project being FOAK. Details of NuScale's SMR can be found at www.nuscalepower.com.

PacifiCorp's capital cost estimates include a 10.36 percent owner's cost for the BCH and NuScale projects. Despite the cost improvements due to the learning curve associated with the AP-1000's previous installations or the NuScale SMR's simplified design attributes, nuclear generation is still expected to have a high LCOE relative to other generation options.

Demand-side Resources

Resource Options and Attributes

Source of Demand-Side Management Resource Data

PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2019-2038, which provided DSM resource opportunity estimates for the 2019 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.[2] 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 2019 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2019 DSM program acquisition targets. To ensure that the 2019 IRP analysis is consistent with existing planned energy efficiency acquisition levels (i.e., Class 2 DSM), expected DSM savings in each state were fixed for calendar year 2019. Beyond 2019, the model optimized DSM selections.

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

- Resource quantities available in each year either in terms of megawatts or megawatt-hours, recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year of the planning period;
- Persistence of resource savings (e.g., energy efficiency equipment measure lives);
- Seasonal availability and hours available (e.g., irrigation load control programs);
- The hourly shape of the resource (e.g., load shape of the resource); and
- Levelized resource costs (e.g., dollars per kilowatt per year for energy efficiency, or dollars per megawatt-hour 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. Resource price differences between states for similar resources reflect differences in each market, such as irrigation pump size and hours of operation, as well as product performance differences. For instance, residential air conditioning load control in Oregon is more expensive than Utah on a unitized or dollar-per-kilowatt-year basis due to climatic differences that result in a lower load impact per installed switch.

Table 6.6 and Table 6.7 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 3 of the 2019 CPA.[3] Potential shown is incremental to the existing DSM resources identified in Table 5.12. For existing program offerings, it is

[2] The 2019 Conservation Potential Study is available on PacifiCorp's demand-side management web page. www.pacificorp.com/energy/integrated-resource-plan/support.html.

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

assumed that the PacifiCorp could begin acquiring incremental potential in 2019. For resources representing new product offerings, it is assumed PacifiCorp could begin acquiring potential in 2020, accounting for the time required for program design, regulatory approval, vendor selection, etc.

Table 6.6 – Demand Response Program Attributes West Control Area

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
DLC Cooling & WH - Res and C&I	33	$44 - $48	18	$136 - $157
DLC Space Heating Res & C&I	n/a	n/a	82	$7 - $27
DLC Room AC - Res	1	$352	n/a	n/a
DLC Smart Thermostat - Res	84	$31 - $54	84	$30 - $91
DLC Smart Appliance - Res	4	$210	4	$221
DLC Elec Vehicle Charging - Res	1	$763	1	$773
DLC Irrigation	26	$37 - $40	n/a	n/a
Third Party Contracts	50	$55 - $56	43	$94 - $100
Ice Energy Storage	3	$134	n/a	n/a
Ancillary Services	9	$14 - $20	n/a	n/a

[1] For consistency in modeling, water heating potential for both seasons is included with the central air conditioning product.

Table 6.7 – Demand Response Program Attributes East Control Area

Product	Summer		Winter	
	20-Year Potential (MW)	Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Levelized Cost ($/kW-yr)
DLC Cooling & WH - Res and C&I	64	($4) - $49	20	$171 - $458
DLC Space Heating Res & C&I	n/a	n/a	55	$9 - $18
DLC Room AC - Res	2	$185	n/a	n/a
DLC Smart Thermostat - Res	167	$5 - $56	41	$77 - $285
DLC Smart Appliance - Res	8	$211	8	$222
DLC Elec Vehicle Charging - Res	4	$686	5	$696
DLC Irrigation	14	$14 - $44	n/a	n/a
Third Party Contracts	118	$53 - $63	90	$100 - $142
Ice Energy Storage	2	$143	n/a	n/a
Ancillary Services	20	($3) - $2	n/a	n/a

[1] For consistency in modeling, water heating potential for both seasons is included with the central air conditioning product.

Energy Efficiency DSM, Energy Supply Curves

The 2019 CPA provided the information to fully assess the potential contribution from DSM energy efficiency resources over the IRP planning horizon. The CPA analysis accounts for known changes in building codes, advancing equipment efficiency standards, market transformation,

resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g. cost-effectiveness criteria).

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[4]
- **Measure:**
  - 89 residential measures
  - 130 commercial measures
  - 111 industrial measures
  - 22 irrigation measures
  - 11 street lighting measures

- **Facility type[5]:**
  - Six residential facility types
  - 28 commercial facility types
  - 30 industrial facility types
  - Two irrigation facility type
  - Four street lighting types

The 2019 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 12.1 million MWh.[6] 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 9.6 million MWh for all five states. The technical achievable potential for all six states for modeling consideration is 13.2 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures

[4] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.
[5] Facility type includes such attributes as existing or new construction, single or multi-family. Facility types are more fully described in Chapter 4 of Volume 2 of the 2019 CPA.
[6] 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.

by building type and state generated over 37,880 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs to reduce the number of combinations to a more manageable number. The range of measure costs in each of the 27 bundles used in the development of the DSM supply curves for the 2019 IRP are the same as those developed for the 2017 IRP.

Bundle development began with the energy efficiency technical potential identified by the 2019 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 aggressive regional planning assumptions, it was assumed that 85 percent of the technical potential for discretionary (retrofit) resources and on average up to 74 percent of lost-opportunity (new construction or equipment upgrade on failure) could be achievable over the 20-year planning period.[7]

For Wyoming, the 2017 CPA applied market ramp rates on top of measure ramp rates to reflect state-specific considerations affecting acquisition rates, such as age of programs, small and rural markets, and current delivery infrastructure for the industrial market. This mechanism was used solely in the Wyoming industrial sector to reflect that program momentum is still building. Recent program accomplishments within this market indicate that this trend has come to an end, therefore the "emerging" market ramp rate was removed from the 2019 CPA.

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 2019 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 were available across six states (including Oregon), which equates to 189 DSM energy efficiency resource supply curves. Table 6.9 shows the 20-year MWh potential for DSM energy efficiency cost bundles, designated by ranges of $/MWh. Table 6.10 shows the associated bundle price after applying cost credits afforded to DSM energy efficiency resources within the model. These cost credits include the following:

- A state-specific transmission and distribution investment deferral cost credit (Table 6.8)
- Stochastic risk reduction credit of $4.74/MWh[8]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[9]

[7] 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.

[8] 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.

[9] The formula for calculating the $/MWh 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.

Table 6.8 – State-specific Transmission and Distribution Credits

State	Transmission Deferral Value ($/KW-year)	Distribution Deferral Value ($/KW-year)	Total
California	$4.16	$6.58	$10.74
Oregon	$4.16	$9.20	$13.36
Washington	$4.16	$11.79	$15.95
Idaho	$4.16	$11.07	$15.22
Utah	$4.16	$9.02	$13.18
Wyoming	$4.16	$5.26	$9.41

The bundle price is the average levelized cost for the group of measures in the cost range, weighted by the potential of the measures. In specifying the bundle cost breakpoints, narrow cost ranges were defined for the lower-cost resources to ensure cost accuracy for the bundles considered more likely to be selected during the resource selection phase of the IRP.

To capture the time-varying impacts of Energy Efficiency resources, each bundle has 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 a given bundle to create a single weighted average load shape for that bundle.

Table 6.9 – 20-Year Cumulative Energy Efficiency Potential by Cost Bundle (MWh)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	38,912	98,747	549,917	1,418,505	210,292	394,131
10 - 20	5,902	35,788	109,045	566,451	76,449	111,399
20 - 30	4,600	67,228	344,713	693,917	69,502	68,278
30 – 40	33,081	47,387	611,481	583,173	166,070	251,490
40 – 50	13,351	24,007	527,253	347,710	52,089	233,920
50 - 60	6,383	38,617	260,480	243,779	46,787	167,890
60 – 70	3,769	18,357	200,163	126,915	47,964	74,670
70 – 80	7,788	8,773	168,229	187,482	29,400	30,877
80 – 90	2,953	12,369	70,325	137,044	24,985	14,797
90 – 100	4,346	14,246	11,637	143,151	23,308	41,359
100 – 110	4,338	7,669	56,015	183,773	18,899	85,951
110 – 120	2,303	15,195	39,623	136,567	14,302	20,700
120 – 130	2,189	13,926	15,688	86,346	25,419	13,837
130 – 140	10,391	7,160	115,146	93,739	35,915	6,266
140 – 150	7,600	4,996	62,573	174,762	18,017	19,605
150 - 160	1,930	5,055	137,281	43,708	13,759	9,608
160 – 170	1,947	9,360	33,284	46,478	10,014	6,732
170 – 180	2,458	2,396	72,957	44,581	7,050	17,150
180 – 190	1,723	1,843	15,798	37,927	11,791	10,135
190 – 200	795	1,362	2,294	34,678	20,928	4,693
200 – 250	14,147	32,139	2,924	115,841	56,428	44,598
250 – 300	10,007	8,305	4,795	100,695	17,555	19,324
300 – 400	11,658	13,731	4,220	170,174	31,286	23,599
400 – 500	1,848	4,078	17,134	55,579	11,608	9,894
500 – 750	6,087	10,509	46,965	131,028	24,455	12,672
750 – 1,000	5,567	4,268	42,758	26,471	22,776	16,008
> 1,000	5,423	9,639	21,631	110,459	23,582	29,420

Table 6.10 – Energy Efficiency Adjusted Prices by Cost Bundle

Bundle	Levelized Bundle Price after Adjustments ($/Mwh)					
	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	0.00	0.00	0.00	0.00	0.00	0.00
10 - 20	7.17	7.38	3.78	8.51	3.22	9.15
20 - 30	17.16	19.50	16.95	18.80	13.09	19.80
30 – 40	30.89	26.09	24.24	28.65	21.00	29.79
40 – 50	39.40	37.37	30.92	36.97	32.09	38.65
50 - 60	48.22	47.70	45.59	47.03	42.11	49.10
60 – 70	58.30	56.11	55.38	58.39	51.24	59.58
70 – 80	68.96	68.95	61.14	68.37	61.77	68.31
80 – 90	75.19	78.50	75.41	77.77	71.98	77.34
90 – 100	85.37	86.97	80.72	87.31	84.14	89.22
100 – 110	96.01	97.72	93.21	97.58	93.27	101.60
110 – 120	106.63	106.27	104.52	106.11	102.29	109.79
120 – 130	116.57	116.90	111.81	118.16	108.59	118.19
130 – 140	128.80	128.48	122.02	126.21	122.26	129.51
140 – 150	136.45	137.75	130.87	133.88	131.34	137.47
150 - 160	149.00	149.10	146.47	146.57	141.99	145.73
160 – 170	156.75	155.37	150.50	158.40	152.30	159.28
170 – 180	167.97	167.15	160.56	167.95	163.07	168.35
180 – 190	179.45	175.72	174.23	177.40	170.44	178.51
190 – 200	188.51	187.27	187.86	187.81	179.70	189.38
200 – 250	226.03	203.75	221.72	213.95	209.13	225.45
250 – 300	272.36	272.99	266.16	264.04	260.89	261.66
300 – 400	324.14	347.69	345.42	322.75	314.55	339.77
400 – 500	423.36	432.51	402.40	431.52	431.94	430.26
500 – 750	604.98	655.21	618.22	611.51	583.68	576.48
750 – 1,000	903.32	836.74	871.60	878.69	867.09	890.11
> 1,000	4,170.84	3,473.61	1,977.88	3,913.95	4,293.67	3,965.04

Distribution Efficiency

PacifiCorp continues to evaluate distribution energy efficiency. The company's streetlight efficiency improvements continue, with older mercury vapor, metal halide and incandescent company owned streetlights being replaced with more efficient lights; high pressure sodium or light emitting diode (LED) each year. The savings associated with this ongoing effort is expected to be too small to warrant reporting.

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.

Neither of these distribution energy efficiency related activities have been modeled as potential resources in this IRP.

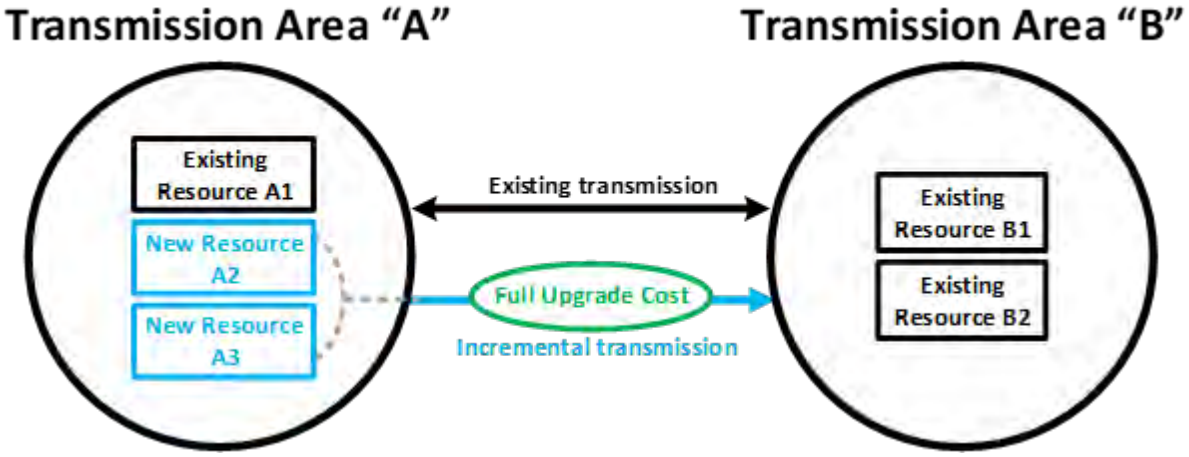
Transmission Resources

As part of it 2019 IRP, PacifiCorp was successfully able to provide the SO model with the ability to view costs and transmission capability associated with certain transmission upgrades that the model could incorporate along with new resource selections as it deemed optimal. This is an improvement from previous IRPs, where transmission upgrades and associated costs had to be determined and accounted for post-portfolio development. New transmission modeling capabilities include the endogenous 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.

Limitations of this approach include transmission options that interact with multiple or complex elements of the IRP transmission topology. Transmission options that are too complex to be captured by the modeling enhancements were therefore studied as sensitivity cases.

Figure 6.7 illustrates the new incremental transmission option modeling capability between two generic transmission areas in the IRP topology. Because the incremental transmission segment (shown in blue) is associated with new resource additions, the model selects them together, endogenously considering the upgrade cost in relation to the benefits of the new expansion resources.

Figure 6.7 – Endogenous Transmission Modeling



In many cases, transmission upgrades do not add incremental transmission capacity to the system, but rather increase interconnection capability. The upgrade cost in such cases is to accommodate additional capacity at a location, and the transmission topology itself is unaffected. For example, additional transmission capacity or transmission reinforcements that are confined to a transmission area incur an upgrade cost but would not add transmission capacity to the larger system. A map of PacifiCorp's transmission system model topology is provided in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

Table 6.11 reports the endogenous incremental transmission options included in the 2019 IRP.

Table 6.11 – Transmission Integration Options by Location and Capacity Increment

IRP Bubble	Added Resource MW		IRP Year	Description of Integration	Affected Topology Path(s)		
	Min	Max			Incremental Capacity (if any)	From Bubble	To Bubble
Portland/N. Coast	1	130	2024	Portland area local reinforcement	-	-	-
	131	580	2030	Portland area (Troutdale) to Albany area 230 kV transmission	450	Portland	Willamette
Willamette	1	615	2024	Albany area local reinforcement	-	-	-
	616	1115	2030	Albany area to Roseburg area 500 kV transmission	1500	Willamette	South-Central Oregon
Yakima	1	405	2024	Yakima area local reinforcement	-	-	-
	406	835	2030	Yakima area to Bend area 230 kV transmission	450	Yakima	South-Central Oregon
Walla Walla	1	100	2030	Walla Walla area to Yakima lower valley transmission	200	Walla Walla	Yakima
South-Central OR/N. California	1	500	2024	Medford area 500-230 kV and 230 kV reinforcement	-	-	-
	501	975	2025	Medford area 500-230 kV and 230 kV reinforcement	-	-	-
Bridger	1	650	2026	Energy Gateway segment D.2 (Anticline-Populus 500 kV transmission line)	650	Bridger	Bridger West (Populus)
Goshen	1	450	2023	Southern Idaho reinforcement	-	-	-
	451	1100	2029	Southern Idaho reinforcement	800	Goshen	Utah North
Wyoming NE	1	460	2023	Energy Gateway segment D.1 (Windstar - Shirley Basin 230 kV line)	-	-	-
Wyoming SW	1	100	2024	Southwest Wyoming area reinforcement	-	-	-
	101	500	2026	Separation of double circuit 230 kV lines, Southwest Wyoming/northern Utah area	-	-	-
Aeolus	1	1920	2024	Energy Gateway segment F (Aeolus-Clover 500 kV transmission line)	1700	Aeolus	Utah South
Utah North	1	300	2021	Northern Utah 345 kV reinforcement	-	-	-
	301	900	2024	Northern Utah 345 kV reinforcement	-	Utah North	Utah North
Utah South	1	300	2021	Utah Valley area 345-138 kV and 138 kV local reinforcement	-	-	-
	301	800	2027	Utah Valley area local 138 kV reinforcement	-	-	-

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.

As proxy resources, FOTs represent a range of purchase transaction types. They are usually standard products, such as heavy load hour (HLH), light load hour (LLH), and super peak (hours ending 13 through 20) and 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.

Solicitations for FOTs can be made years, quarters or months in advance, however, most transactions made 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.

Three FOT types were included for portfolio analysis in the 2019 IRP: an annual flat product, a HLH July for summer, and a HLH December for winter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. The HLH transactions represent purchases received 16 hours per day, six days per week for July and December. Table 6.12 shows the FOT resources included in the IRP models, identifying the market hub, product type, annual megawatt capacity limit, and availability. PacifiCorp develops its FOT limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and market depth, and with consideration of regional resource supply (see Volume II, Appendix J for an assessment of western resource adequacy). Prices for FOT purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges, as applicable. Additional discussion of how FOTs are modeled during the resource portfolio development process of the IRP is included in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

Table 6.12 - Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type Available over Study Period	Megawatt Limit and Availability (MW)	
	Summer (July)	Winter (December)
Mid-Columbia (Mid-C)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	400	400
Heavy Load Hour ("6X16")	375	375
California Oregon Border (COB)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	250	250
Nevada Oregon Border (NOB)		
Heavy Load Hour ("6X16")	100	100
Mona		
Heavy Load Hour ("6X16")	300	300

CHAPTER 7 – MODELING AND PORTFOLIO EVALUATION APPROACH

CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios. The 2019 IRP modeling and evaluation approach consists of three basic steps used to select a preferred portfolio—coal studies, portfolio development, and final portfolio screening.
- PacifiCorp uses the System Optimizer (SO) model to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp ultimately produced over 50 different resource portfolios, informed by the coal studies summarized in Volume II, Appendix R (Coal Studies). Each resource portfolio is unique with regard to the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years.
- PacifiCorp uses the Planning and Risk model (PaR) to perform stochastic risk analysis of the portfolios produced by the SO model. For top-performing resource portfolios, PaR studies were developed to evaluate 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 price-policy scenario was developed to evaluate performance assuming a CO_2 price signal that aligns with the social cost of carbon. Taken together, there are four distinct price-policy scenarios (medium gas/medium CO_2, high gas/high CO_2, low gas/zero CO_2, and the social cost of carbon). The resulting cost and risk metrics are then used to compare portfolio alternatives and inform selection of the preferred portfolio.
- Taking into consideration stakeholder comments received during the public-input process, PacifiCorp also developed eight sensitivity cases designed to highlight the impact of specific planning assumptions on future resource selections along with the associated impact on system costs and stochastic risks. These sensitivities are informative in nature and support development of an acquisition path analysis, but were not considered for selection of the preferred portfolio.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from PaR, comparing resource portfolios on the basis of 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 a target planning reserve margin. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

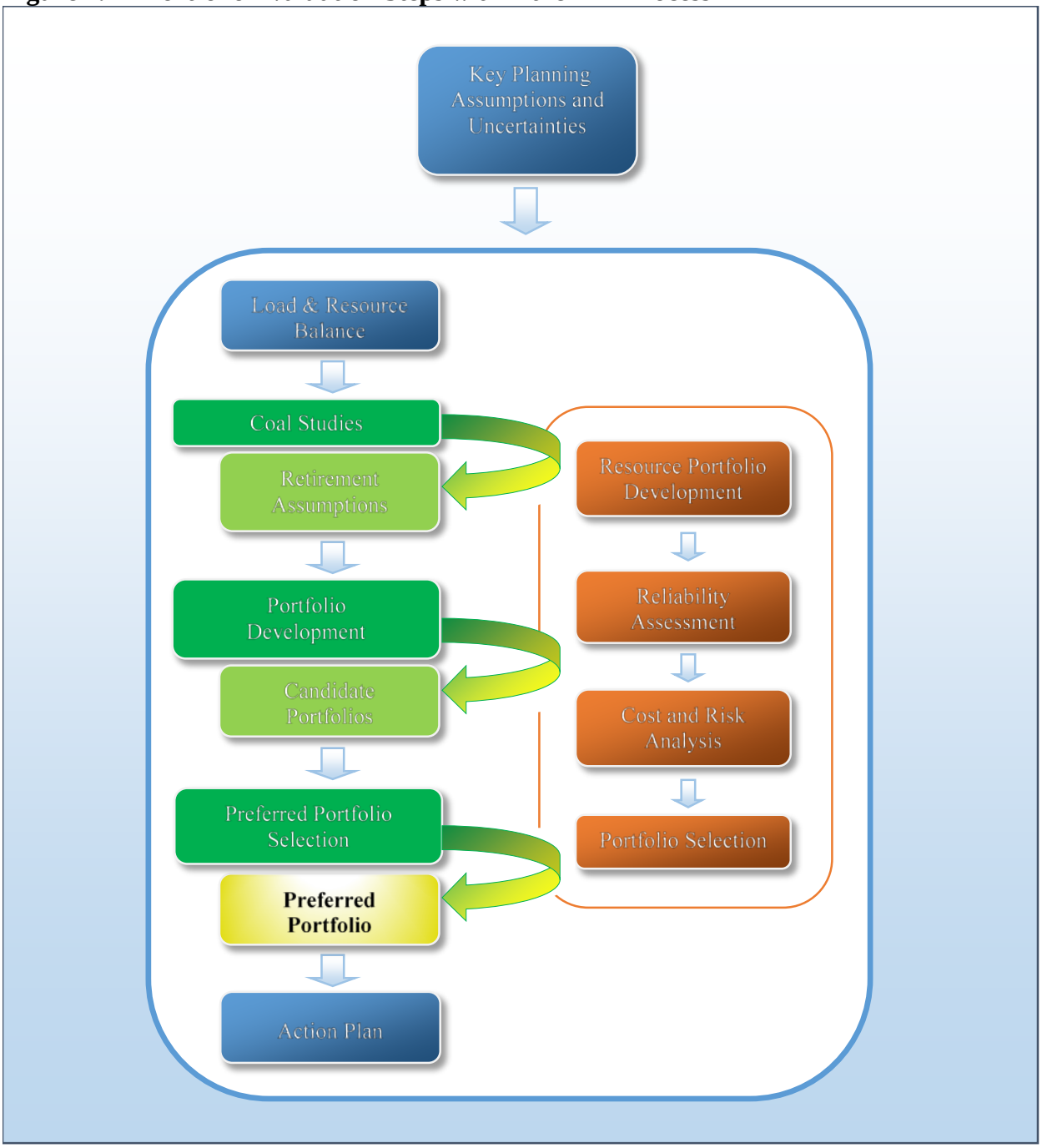
The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter describes the cases examined at each modeling and evaluation step. The

results of PacifiCorp's modeling and portfolio analysis are summarized in Chapter 8 (Modeling and Portfolio Evaluation Approach).

Modeling and Evaluation Steps

Figure 7.1 summarizes the three modeling and evaluation steps for the 2019 IRP, highlighted in green. The three steps are (1) coal studies, (2) portfolio development, and (3) the final portfolio screening. The result of the final screening step is selection of the preferred portfolio.

Figure 7.1 – Portfolio Evaluation Steps within the IRP Process



For each modeling and evaluation step, PacifiCorp developed unique resource portfolios, analyzed 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. The basic portfolio evaluations within each step are highlighted in orange in Figure 7.1 above and include:

- 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 SO model, which is used to produce resource portfolios with sufficient capacity to achieve a target planning reserve margin. Each resource portfolio is uniquely characterized by the type, timing, location, and amount of new resources in PacifiCorp's system over time.

- Reliability Assessment
  The 2019 IRP adds a reliability assessment phase to its portfolio processing, accounting for demonstrated reliability shortfalls driven by the replacement of flexible, dispatchable resources with intermittent variable resources. The reliability assessment uses up to 16 PaR deterministic model runs to assess hourly capacity shortfalls for years 2023 through 2038. This information is then used in the SO model to optimize the selection of additional reliability resources.

- Cost and Risk Analysis
  Resource portfolios developed by the SO model are simulated in PaR 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.

- Portfolio Selection
  The portfolio selection process is based upon modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the present value revenue requirement (PVRR) of system costs, assessed across a range of price-policy scenarios on an expected-value basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the expected value 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.

Resource Portfolio Development

Resource expansion plan modeling, performed with the SO model, is used to produce resource portfolios with sufficient capacity to achieve a target planning reserve margin over the 20-year study horizon. Each resource portfolio is uniquely characterized by the type, timing, location, and amount 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 resources (DSM). Changes to these input variables cause changes to the resource mix, which influences system costs and risks.

System Optimizer

The SO model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints. Over the 20-year planning horizon, it optimizes resource additions subject to resource costs and capacity constraints (summer peak loads, winter peak loads, plus a target planning reserve margin for each load area represented in the model). In the event that an early retirement of an existing generating resource is assumed for a given planning scenario, the SO model will select additional resources as required to meet summer and winter peak loads inclusive of the target planning reserve margin.

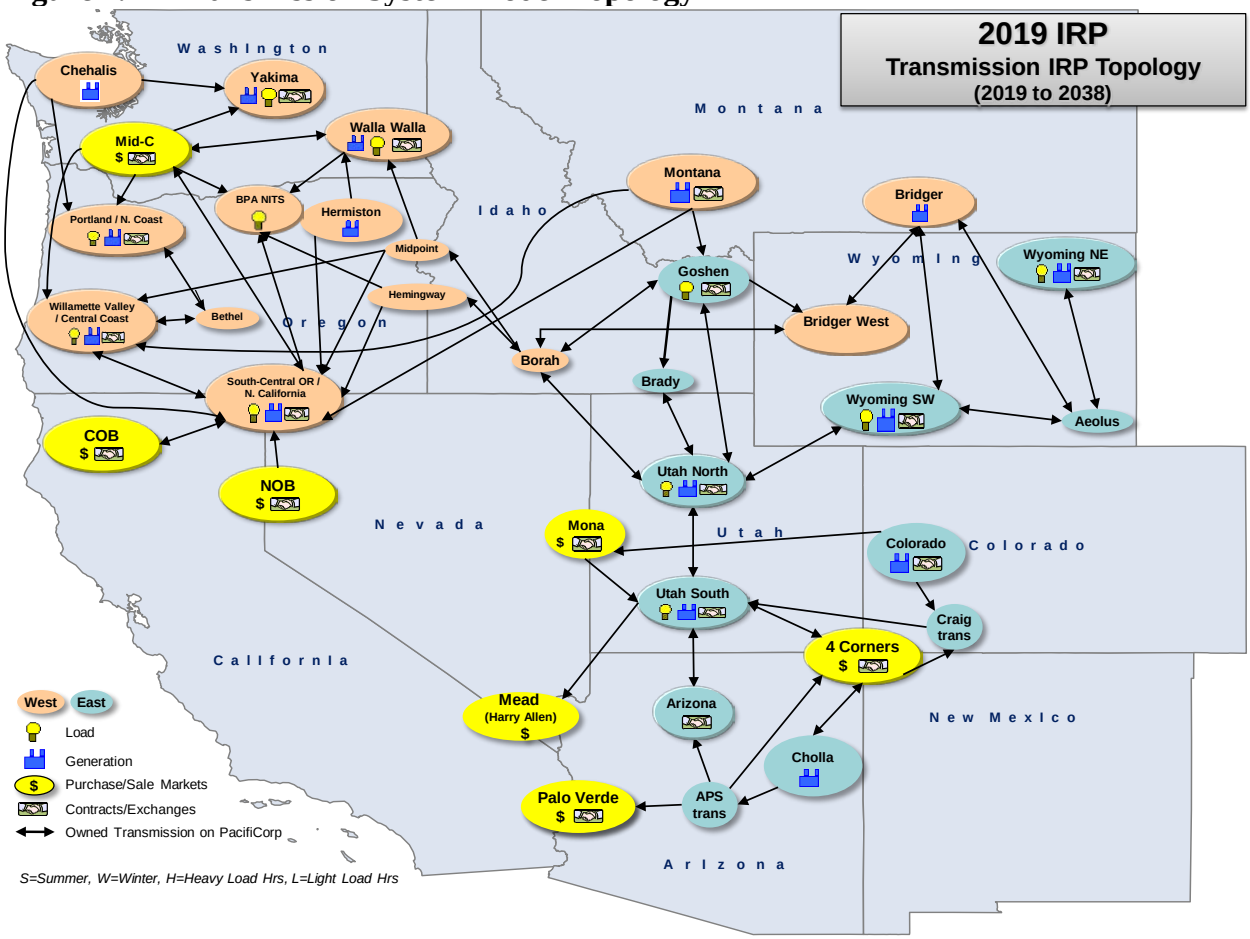
To accomplish these optimization objectives, the SO model performs a time-of-day least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on a representative-week method. Time-of-day hourly blocks are simulated according to a user-specified day-type pattern representing an entire week. Each month is represented by one week, and the model scales output results to the number of days in the month and then the number of months in the year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, spot market purchase costs, spot 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.

The SO model is also used in developing the reliability portfolio for each case, receiving reliability requirements determined by the PaR model as described in Volume II, Appendix R, Figure R.1 (Coal Studies), applies to all resource portfolio-development in the 2019 IRP.

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 7.2 shows the 2019 IRP transmission system model topology.

Figure 7.2 – Transmission System Model Topology



Transmission Costs

In developing resource portfolios for the 2019 IRP, PacifiCorp includes new modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and amount of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional details on endogenous transmission modeling are provided in Volume I, Chapter 6 (Resource Options).

Resource Adequacy

Resource adequacy is modeled in the portfolio-development process by ensuring each portfolio meets a target planning reserve margin. In its 2019 IRP, PacifiCorp continues to apply a 13 percent target planning reserve margin. The planning reserve margin, which influences the need for new resources, is applied to PacifiCorp's coincident system peak load forecast net of offsetting "load resources" such as energy efficiency. Planning to achieve a 13 percent planning reserve margin ensures that PacifiCorp has sufficient resources to meet its peak load, recognizing that there is a possibility 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. Volume II, Appendix I (Planning Reserve Margin Study) summarizes PacifiCorp's updated planning reserve margin study that supports selection of a 13 percent target planning reserve margin in the 2019 IRP.

New Resource Options

Dispatchable Thermal Resources

The SO model performs time-of-day least cost dispatch of existing and potential new thermal resources to meet load while minimizing costs. Dispatch costs applicable to thermal resources include fuel costs, non-fuel variable operations & maintenance (VOM) costs, and the cost of emissions, as applicable. For existing and potential new dispatchable thermal resources, the SO model uses generator-specific inputs for fuel costs, VOM, heat rates, emission rates, and any applicable price for emissions to establish the dispatch cost of each generating unit for each dispatch interval. Thermal resources are dispatched by least cost merit order. The power produced by these resources can be used to meet load or to make off-system sales at times when resource dispatch costs fall below market prices. Conversely, at times when dispatch costs exceed market prices, off-system purchases can displace dispatchable thermal generation to minimize system energy costs. Dispatch of thermal resources reflects any applicable transmission constraints connecting generating resources with both load and market bubbles as defined in the transmission topology for the model.

Front Office Transactions

Front office transactions (FOTs) represent short-term firm market purchases 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., prompt month forward, 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, which differ by delivery pattern and delivery period, that 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 capacity contribution of short-term firm market purchases are accounted for in the portfolio-development process. For capacity optimization modeling, short-term firm forward transactions are represented as FOTs and configured in the SO model with either an annual flat, summer-on-peak (July), or winter on-peak (December) delivery pattern in every year of the twenty-year planning horizon. As configured in SO, FOTs contribute capacity toward meeting the 2019 IRP's 13 percent target planning reserve margin and supply system energy consistent with the assumed FOT delivery pattern.

Unlike FOTs, system balancing transactions do not contribute capacity toward meeting the 13 percent target planning reserve margin. System balancing transactions include hourly off-system sales and hourly off-system purchases, representing market activities that minimize system energy costs as part of the economic dispatch of system resources, including energy from any FOTs included in a resource portfolio.

A description of FOT limits assumed in the 2019 IRP is included in Volume I, Chapter 6 (Resource Options). PacifiCorp's evaluation of resource adequacy in the western power markets is summarized in Volume II, Appendix J (Western Resource Adequacy Evaluation).

Demand-Side Management

The SO model can select incremental DSM resources during portfolio optimization development in each modeling and evaluation step. Selection of DSM resources is made from supply curves that define how much of a DSM resource can be acquired at a given cost.

Energy Efficiency (Class 2 DSM) 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 (Class 1 DSM) 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). The SO model evaluates demand response resources by considering capacity contribution, cost, and operating characteristics. Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available. Additional discussion of DSM resources modeled in the 2019 IRP is included in Volume I, Chapter 6 (Resource Options) and in Volume II, Appendix D (Demand-Side Management Resources).

Wind and Solar Resources

Certain wind and solar resources 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 represents the expected generation levels in which half of the time actual generation would fall below expected levels, and half of the time actual generation would be above expected levels assuming no curtailments.

The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand over time. These values are dependent on the underlying portfolio, and are expected to decline as the penetration of resources of the same type increases. For the purposes of portfolio selection, PacifiCorp developed capacity-contribution values specific to the five wind profiles and five solar profiles used for proxy resources. In addition, PacifiCorp developed contribution values for two levels of wind and solar penetration. A "high" capacity-contribution block allowed for up to 2,000 MW of new wind capacity and 1,000 MW of new solar capacity (roughly a 50 percent increase from the initial portfolio levels). Any additional wind and solar capacity beyond the first block was assigned a "low" capacity-contribution value, calculated based on an additional 2,000 MW of new wind capacity and 1,000 MW of new solar capacity. PacifiCorp also developed capacity-contribution values for each of the wind and solar locations when combined with lithium-ion battery storage

with a maximum output equal to 25 percent of the renewable resource nameplate capacity and assuming a four-hour storage duration. Volume II, Appendix N (Capacity Contribution Study) summarizes PacifiCorp's capacity contribution study and the resulting values.

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;
- 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 SO 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 fuel costs (for example, the cost of natural gas for expanding air with gas turbine expanders). To determine the least-cost resource expansion plan, the SO model accounts for conventional generation system performance and cost characteristics of the storage resource, including capital cost, size of the storage and time to fill the storage, heat rate (if fuel is used), operating and maintenance cost, minimum capacity, and maximum capacity. Because they are energy-limited, an energy storage resource may not be able to cover the entirety of an extended outage. For the 2019 IRP, PacifiCorp calculated capacity contribution values based on the duration of energy storage. Volume II, Appendix N (Capacity Contribution Study) summarizes the capacity contribution study and the resulting values for energy storage.

Capital Costs and End-Effects

The SO model uses annual capital recovery factors to convert capital dollars into real levelized revenue requirement costs to address end-effects that arise with capital-intensive projects that have different lives and in-service dates. All capital costs evaluated in the IRP are converted to real levelized revenue requirement costs. Use of real levelized revenue requirement costs is an established and preferred 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 real 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 grows at inflation such that the PVRR is identical to the PVRR of the nominal annual requirement when using the same nominal discount rate. For the 2019 IRP, the PVRR is calculated inclusive of real levelized capital revenue requirement through the end of the 2038 planning period.

General Assumptions

Study Period and Date Conventions

PacifiCorp executes its 2019 IRP models for a 20-year period beginning January 1, 2019 and ending December 31, 2038. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, with the exception of 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.

Inflation Rates

The 2019 IRP model simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.28 percent is assumed. The annual escalation rate reflects the average of annual inflation rate projections for the period 2019 through 2038, using PacifiCorp's September 2018 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the Consumer Price Index.

Discount Factor

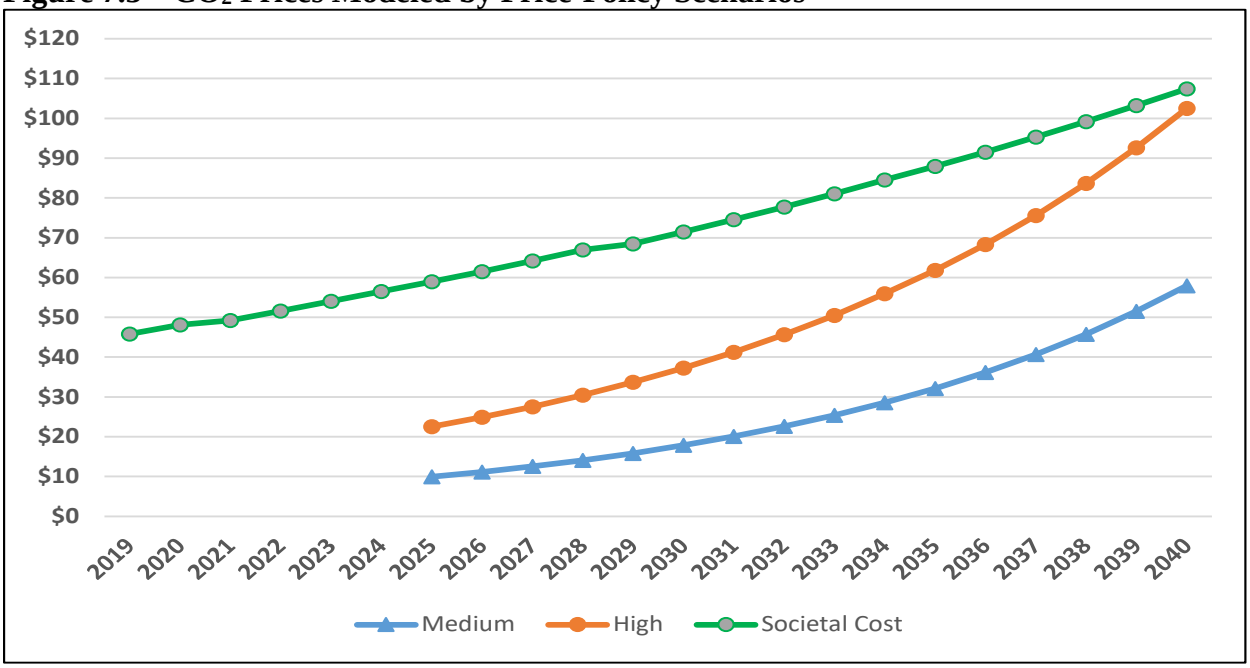
The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2017 IRP is 6.92 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[1] PVRR figures reported in the 2019 IRP are reported in January 1, 2019 dollars.

CO2 Price Scenarios

PacifiCorp uses four different CO_2 price scenarios in the 2019 IRP—zero, medium, high, and a price forecast that aligns with the social cost of carbon. The medium and high scenario are derived from expert third-party multi-client "off-the-shelf" subscription services. Both of these scenarios apply a CO_2 price as a tax beginning 2025. PacifiCorp initially proposed using a medium CO_2 price forecast beginning in 2030, consistent with the start year assumed by the third-party forecast reviewed, but in response to stakeholder interests, PacifiCorp agreed to align the start year in the medium case with the start year proposed for the high case (2025). Figure 7.3 summarizes the CO_2 price assumptions used in the 2019 IRP (the zero price, no CO_2 scenario is not shown).

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

Figure 7.3 – CO_2 Prices Modeled by Price-Policy Scenarios



Wholesale Electricity and Natural Gas Forward Prices

For 2019 IRP modeling purposes, eight electricity price forecasts were used: the official forward price curve (OFPC) and seven 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 2019 IRP modeling was initiated, the September 2018 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.[2] As such, these 36 months are market forwards as of September 28, 2018. 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[3] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through October 2021 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

[2] The September 2018 OFPC prompt month is November 2018; October 2018 is "balance of month".
[3] AURORAXMP is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

gas price scenarios are also derived from expert third-party multi-client "off-the-shelf" subscription services.

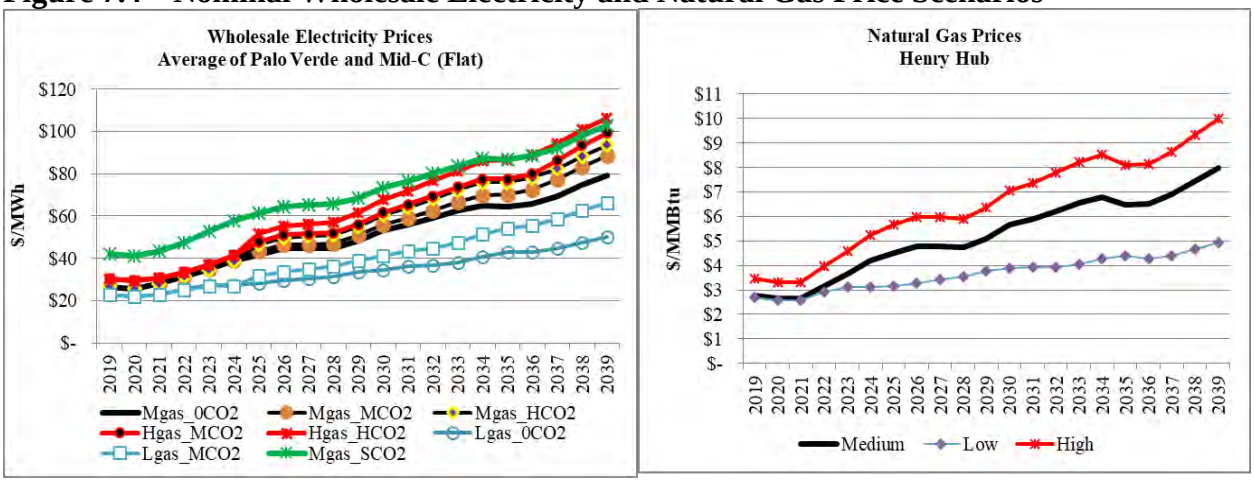
PacifiCorp's OFPC for electricity and each of its seven scenarios were developed from one of three (medium, low, high) underlying expert third-party natural gas price forecasts in conjunction with one of four CO_2 price scenarios.[4] The September 2018 OFPC does not assume any CO_2 policy or tax in conjunction with its medium gas price forecast. However, PacifiCorp's 2019 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 2019 IRP medium case differs from that of the September 2018 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, whose implementation and design specifics are not known.

The 2019 IRP medium CO_2 compliance assumption differs from that used in either PacifiCorp's 2015 or 2017 IRPs. In its 2015 IRP PacifiCorp's OFPC incorporated the U.S. Environmental Protection Agency's (EPA's)[5] proposed Clean Power Plan (CPP) rule to improve CO_2 emissions performance rates for affected power plants. To reflect the CPP in Aurora, PacifiCorp applied state emission rate constraints in the model, assuming energy efficiency goals assumed by EPA in its calculation of state emission rate targets. Upon finalization of the CPP, and in its 2017 IRP, PacifiCorp's OFPC for electricity and each of its six scenarios were developed from one of three (low, medium, high) underlying expert third-party natural gas price forecasts in conjunction with one of three CO_2 compliance designs tied to the CPP. But on March 28, 2017, President Trump issued an Executive Order directing the EPA to review the CPP and, if appropriate, suspend, revise, or rescind the CPP, as well as related rules and agency actions. Thus, essentially rendering the CPP an artifact of the Obama Administration. On June 19, 2019 the EPA issued its Affordable Clean Energy (ACE) Rule replacing the CPP. ACE does not set CO_2 emission cuts by state but, instead, allows states to determine efficiency improvements.

Figure 7.4 summarizes the eight wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2019 IRP.

[4] Zero CO_2, medium CO_2 price, high CO_2 price, and a social based cost of CO_2.
[5] EPA: Environmental Protection Agency.

Figure 7.4 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Cost and Risk Analysis

Planning and Risk

PaR uses the same common input assumptions described for SO model with additional data provided by the SO model results (e.g., the capacity expansion portfolio including reliability resource additions). While the SO model supplies a capacity view developing an optimized portfolio for each case, PaR is able to bring the advantages of stochastic-driven risk metrics to the evaluation of the studies while also capturing additional operational considerations that the SO model does not asses (i.e., operating reserve requirements). While PaR cost-risk metrics are ultimately used in the preferred portfolio selection, the SO model results can be informative, especially in their role as a magnitude and direction indicator to compare to PaR outcomes.

PaR is also used to perform the hourly deterministic reliability assessments for each case, as described in detail in Volume II, Appendix R (Coal Studies). The PaR reliability assessment informs selection of reliability resources in the SO model. Figure R.1 (Reliability Studies Methodology Process), presented in Volume II, Appendix R (Coal Studies) applies to all resource portfolio development in the 2019 IRP.

Cost and Risk Analysis

Once unique resource portfolios are developed using the SO model, 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 PaR.

The stochastic simulation in PaR produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The PaR 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. Wind and solar generation is not modeled with stochastic parameters; however, the incremental reserve requirements associated with uncertainty and variability in wind generation, as determined in the updated flexible reserve study, are captured in the stochastic simulations.

PacifiCorp's updated flexible reserve study is provided in Volume II, Appendix F (Flexible Reserve Study).

The stochastic parameters used in PaR for the 2019 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 on how the stochastic parameters for the 2019 IRP were developed.

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 during the 4-year period ending December 2015. 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 6 (Resource Options). Table 7.1 through Table 7.8 summarize updated stochastic parameters and seasonal price correlations for the 2019 IRP.

Table 7.1 – Short-Term Load Stochastic Parameters

Short-Term Volatility	CA/OR without Portland	Portland	ID	UT	WA	WY
Winter 2019 IRP	0.042	0.039	0.035	0.021	0.053	0.016
Spring 2019 IRP	0.035	0.033	0.065	0.028	0.037	0.018
Summer 2019 IRP	0.042	0.050	0.051	0.045	0.050	0.016
Fall 2019 IRP	0.042	0.039	0.042	0.035	0.043	0.017
Short-Term Mean Reversion	**CA/OR without Portland**	**Portland**	**ID**	**UT**	**WA**	**WY**
Winter 2019 IRP	0.188	0.177	0.153	0.363	0.181	0.273
Spring 2019 IRP	0.368	0.241	0.204	0.595	0.341	0.254
Summer 2019 IRP	0.194	0.280	0.095	0.213	0.157	0.235
Fall 2019 IRP	0.257	0.242	0.218	0.249	0.203	0.267

Table 7.2 – Short-Term Gas Price Parameters

Short-Term Volatility	East Gas	West Gas
Winter 2019 IRP	0.111	0.120
Spring 2019 IRP	0.039	0.061
Summer 2019 IRP	0.025	0.049
Fall 2019 IRP	0.036	0.044
Short-Term Mean Reversion	**East Gas**	**West Gas**
Winter 2019 IRP	0.110	0.092
Spring 2019 IRP	0.152	0.265
Summer 2019 IRP	0.102	0.105
Fall 2019 IRP	0.071	0.107

Table 7.3 – Short-Term Electricity Price Parameters

Short-Term Volatility	Four Corners	COB	Mid-Columbia	Palo Verde
Winter 2019 IRP	0.098	0.134	0.166	0.092
Spring 2019 IRP	0.104	0.261	0.475	0.075
Summer 2019 IRP	0.155	0.300	0.213	0.141
Fall 2019 IRP	0.101	0.102	0.103	0.098
Short-Term Mean Reversion	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**
Winter 2019 IRP	0.125	0.119	0.140	0.110
Spring 2019 IRP	0.434	0.551	0.551	0.211
Summer 2019 IRP	0.338	0.463	0.271	0.220
Fall 2019 IRP	0.370	0.257	0.279	0.415

Table 7.4 – Winter Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.629	1.000				
COB	0.353	0.576	1.000			
Mid - Columbia	0.382	0.573	0.942	1.000		
Palo Verde	0.662	0.835	0.610	0.594	1.000	
Natural Gas West	0.891	0.567	0.395	0.421	0.609	1.000

Table 7.5 – Spring Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.204	1.000				
COB	0.099	0.338	1.000			
Mid - Columbia	0.069	0.358	0.864	1.000		
Palo Verde	0.327	0.621	0.392	0.307	1.000	
Natural Gas West	0.553	0.058	0.080	0.070	0.132	1.000

Table 7.6 – Summer Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.052	1.000				
COB	-0.004	0.272	1.000			
Mid - Columbia	0.024	0.290	0.848	1.000		
Palo Verde	-0.001	0.521	0.444	0.506	1.000	
Natural Gas West	0.453	0.054	0.050	0.096	0.009	1.000

Table 7.7 – Fall Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.135	1.000				
COB	0.149	0.362	1.000			
Mid - Columbia	0.124	0.223	0.780	1.000		
Palo Verde	0.129	0.528	0.627	0.444	1.000	
Natural Gas West	0.731	0.100	0.128	0.133	0.066	1.000

Table 7.8 – Hydro Short-Term Stochastic

	Short Term Volatility	Short-Term Mean Reversion
Winter 2019 IRP	0.212	0.632
Spring 2019 IRP	0.162	0.501
Summer 2019 IRP	0.168	1.512
Fall 2019 IRP	0.301	0.863

Figure 7.5 and Figure 7.6 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for Mid-C and Palo Verde market hubs based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Mid-C electricity prices, differences between the first and 99th percentiles range from $21.64/MWh to $79.88/MWh during the 20-year study period. For Palo Verde electricity prices, the difference between the first and 99th percentiles range from $26.57/MWh to $99.34/MWh.

Figure 7.5 – Simulated Annual Mid-C Electricity Market Prices

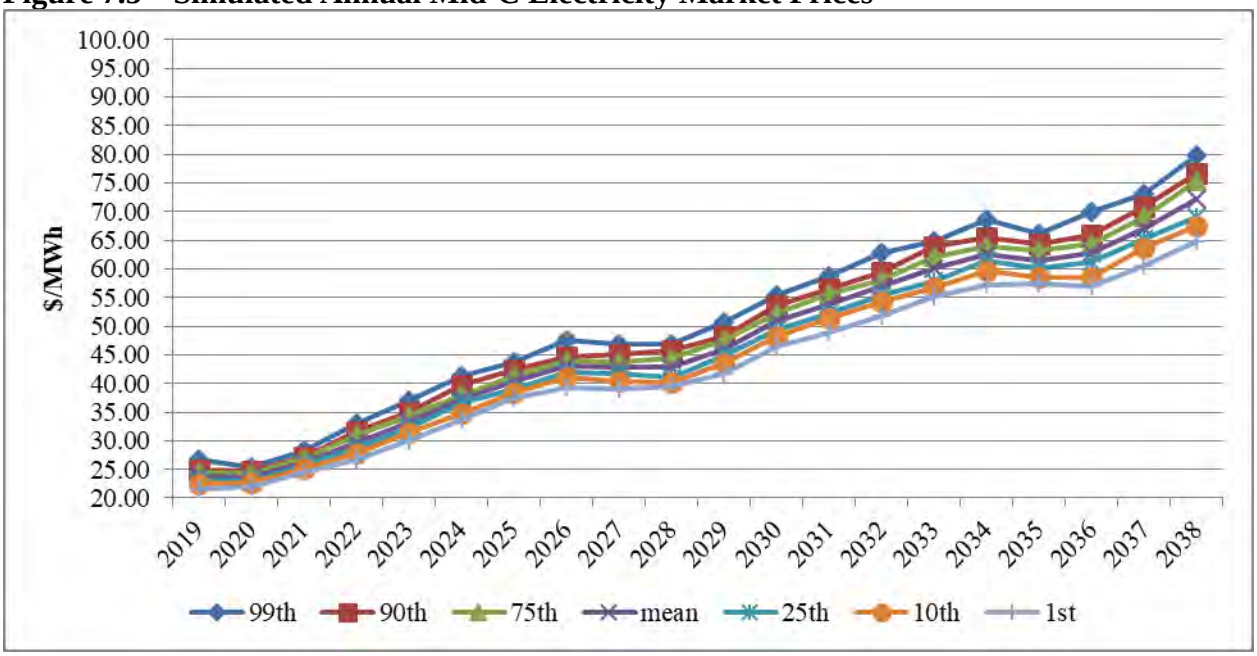


Figure 7.6 – Simulated Annual Palo Verde Electricity Market Prices

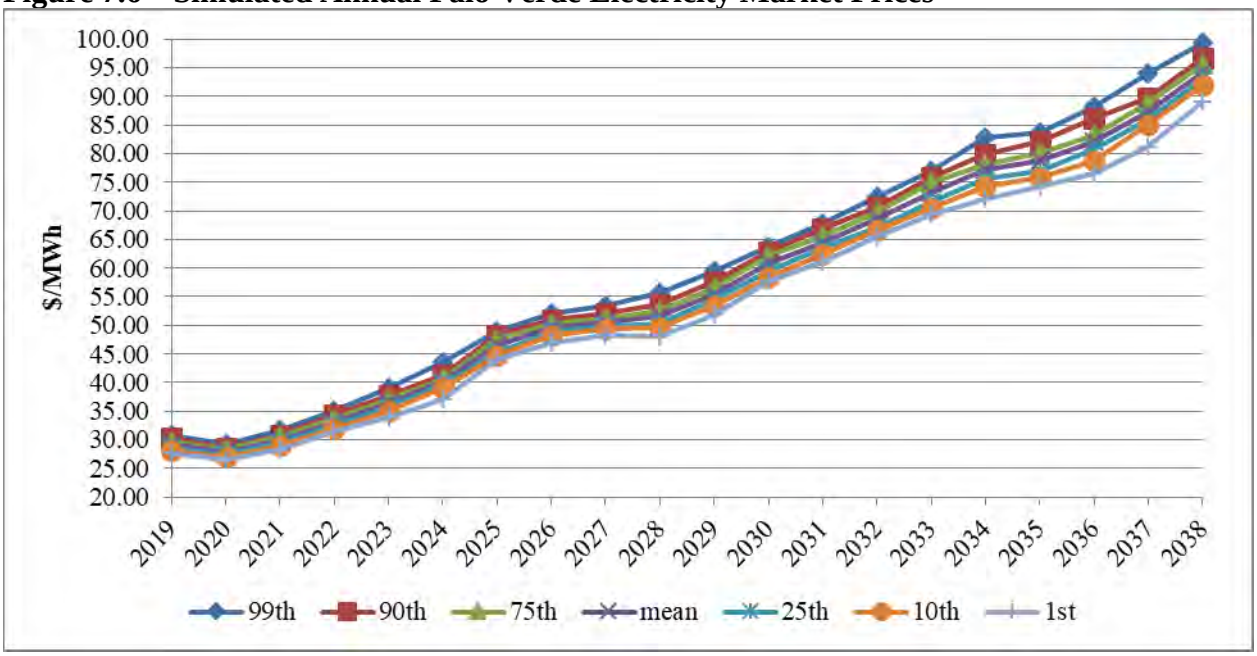


Figure 7.7 and Figure 7.8 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for west and east natural gas prices. For west natural gas prices, differences between the first and 99th percentiles range from $1.85/ Million British thermal units (MMBtu) to $7.22/MMBtu during the 20-year study period. For east natural gas prices, differences between the first and 99th percentiles range from $2.00/MMBtu to $7.64/MMBtu.

Figure 7.7 – Simulated Annual Western Natural Gas Market Prices

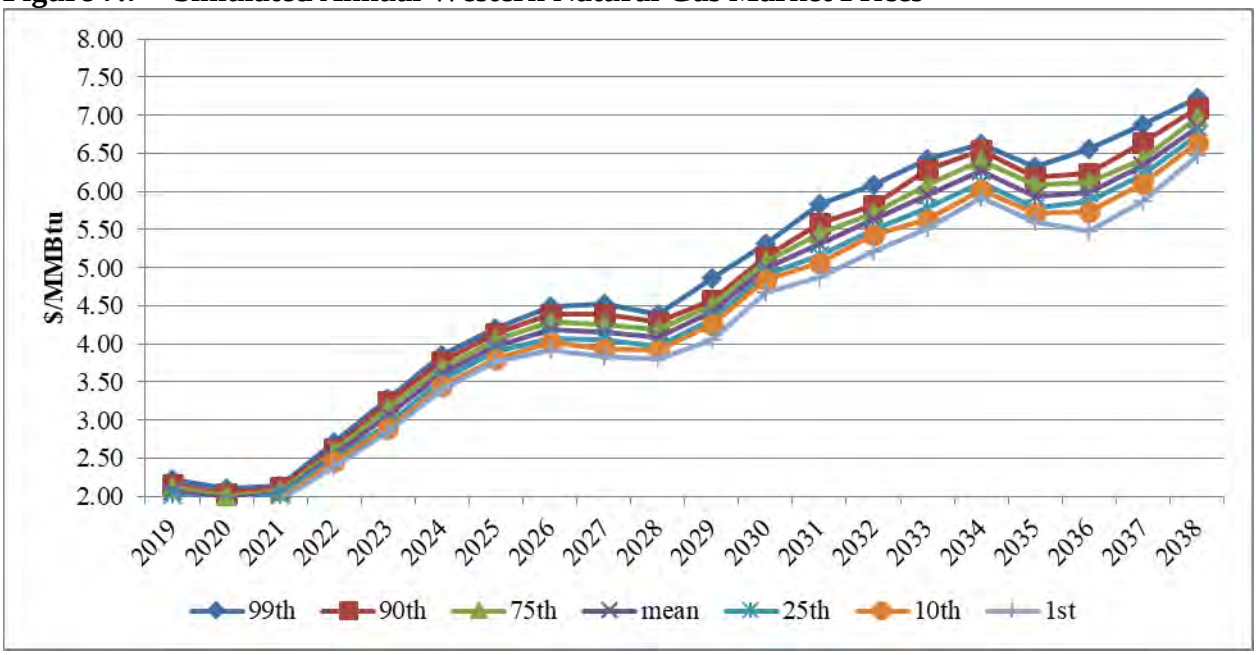


Figure 7.8 - Simulated Annual Eastern Natural Gas Market Prices

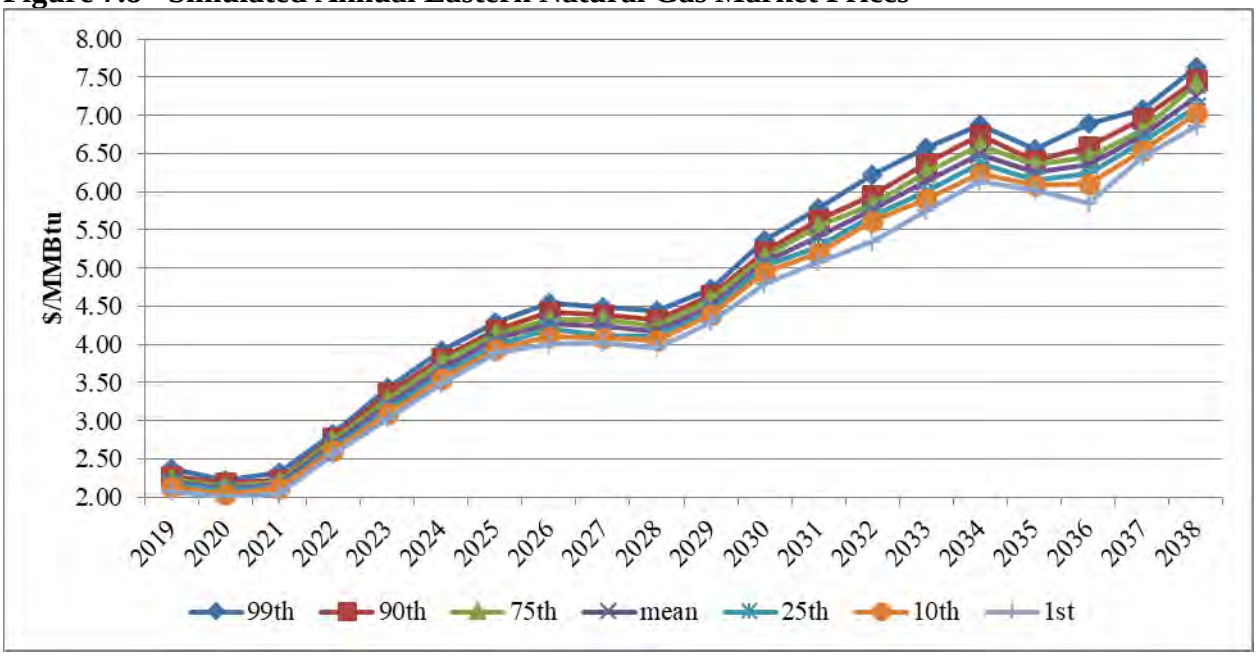


Figure 7.9 through Figure 7.14 show annual loads by load area and for PacifiCorp's system at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Idaho (Goshen) load, the annual differences between the first and 99th percentiles range from 192 gigawatt-hours (GWh) to 348 GWh. For Utah load, the annual difference ranges from 1,204 GWh to 2,772 GWh. For Wyoming load, the annual difference range from 137 GWh to 271 GWh. For Oregon/California load, annual differences range from 746 GWh to 1,528 GWh. For Washington load, the annual difference ranges from 315 GWh to 557 GWh. For PacifiCorp's system load, the annual difference ranges from 2,386 GWh to 4,354 GWh.

Figure 7.9 - Simulated Annual Idaho (Goshen) Load

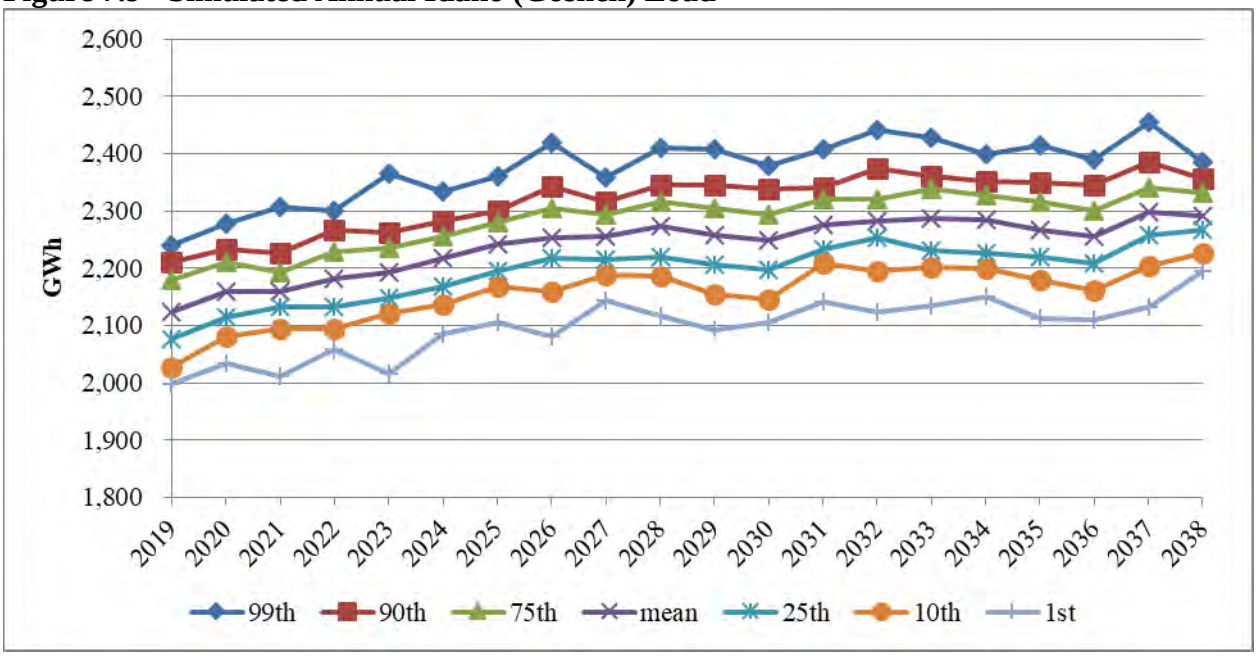


Figure 7.10 - Simulated Annual Utah Load

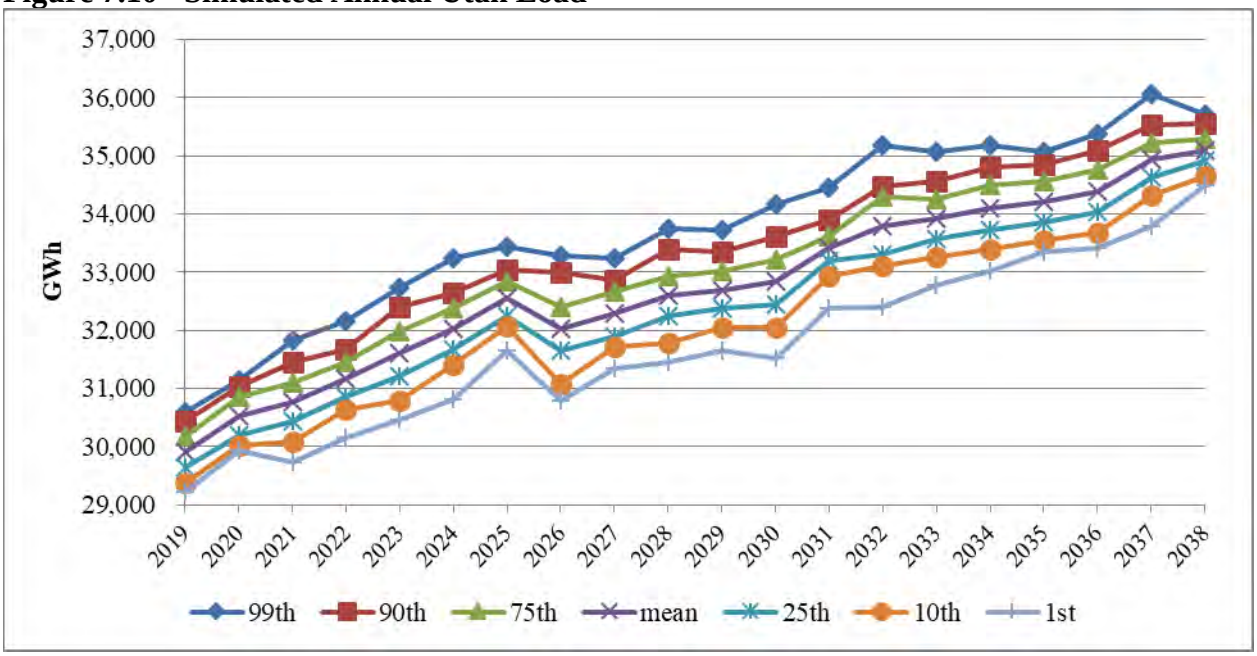


Figure 7.11 - Simulated Annual Wyoming Load

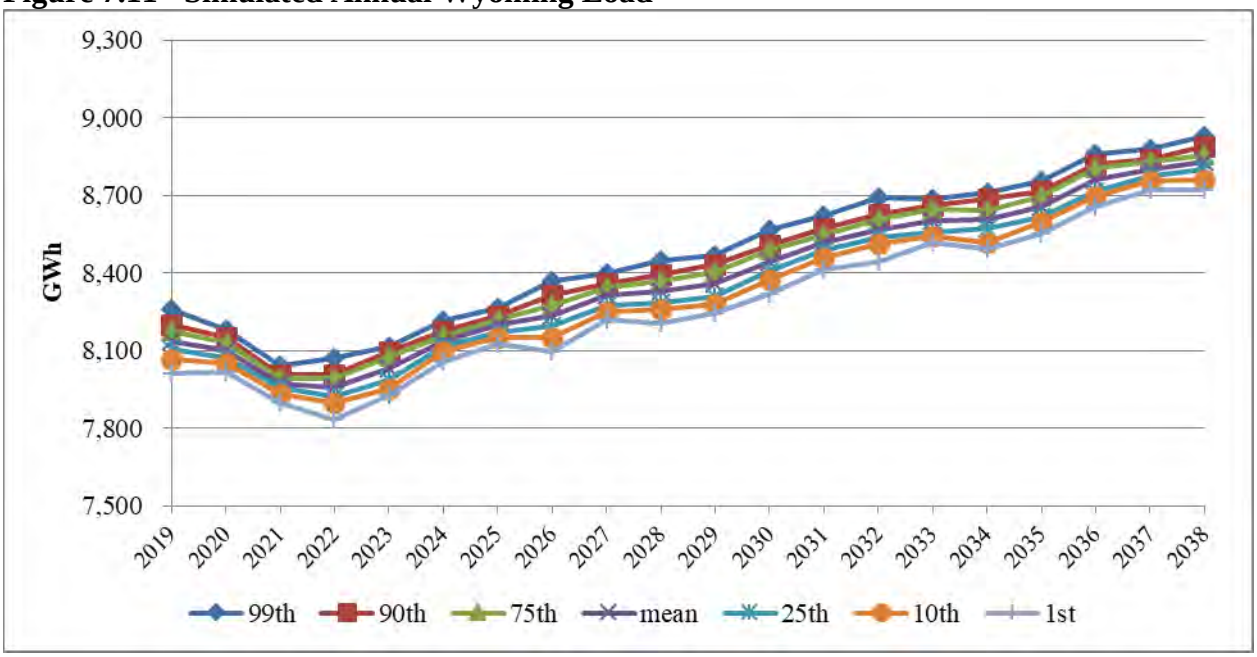


Figure 7.12 - Simulated Annual Oregon/California Load

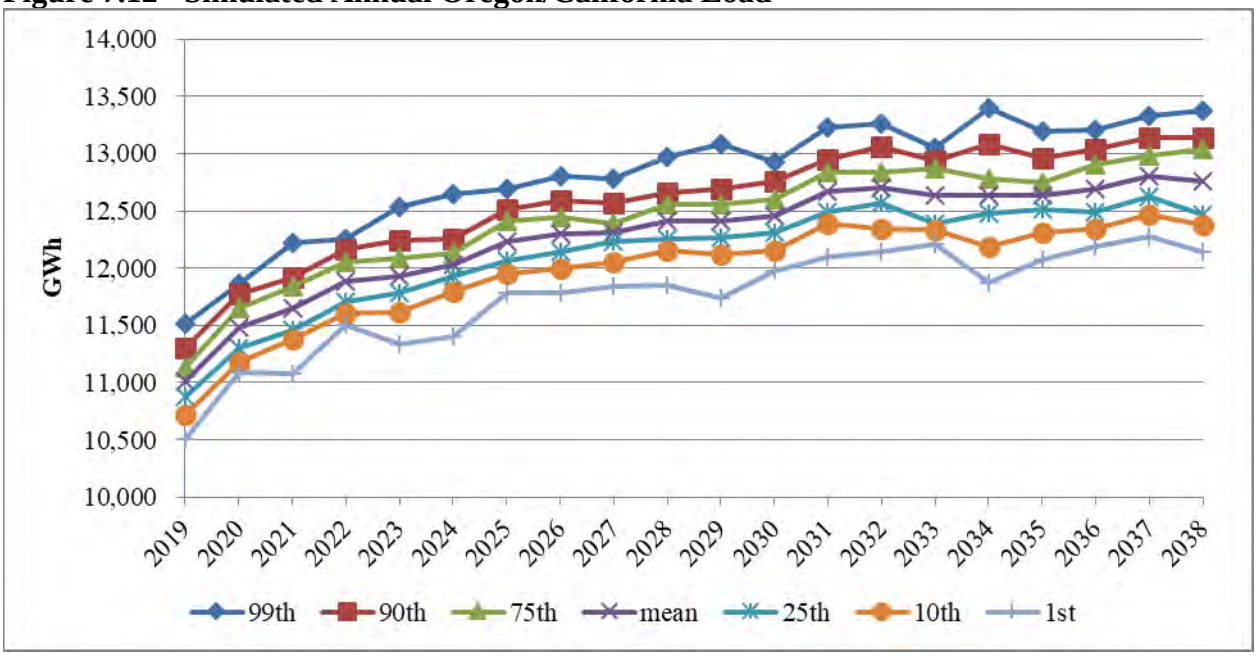


Figure 7.13 - Simulated Annual Washington Load

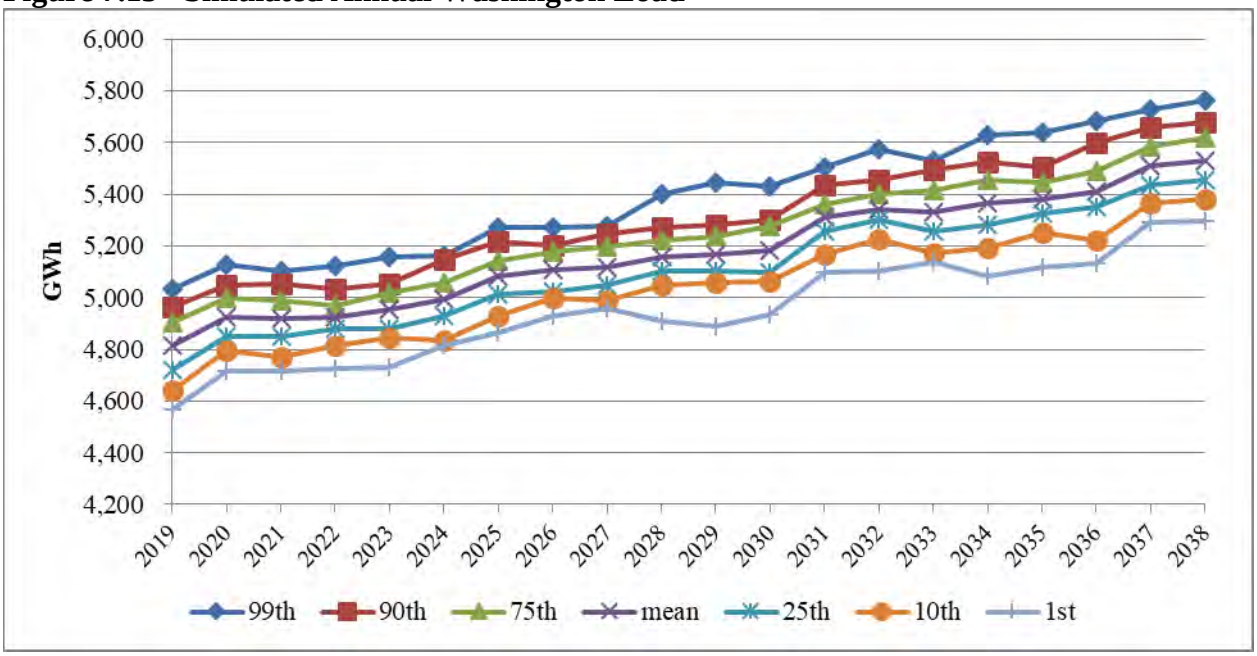


Figure 7.14 - Simulated Annual System Load

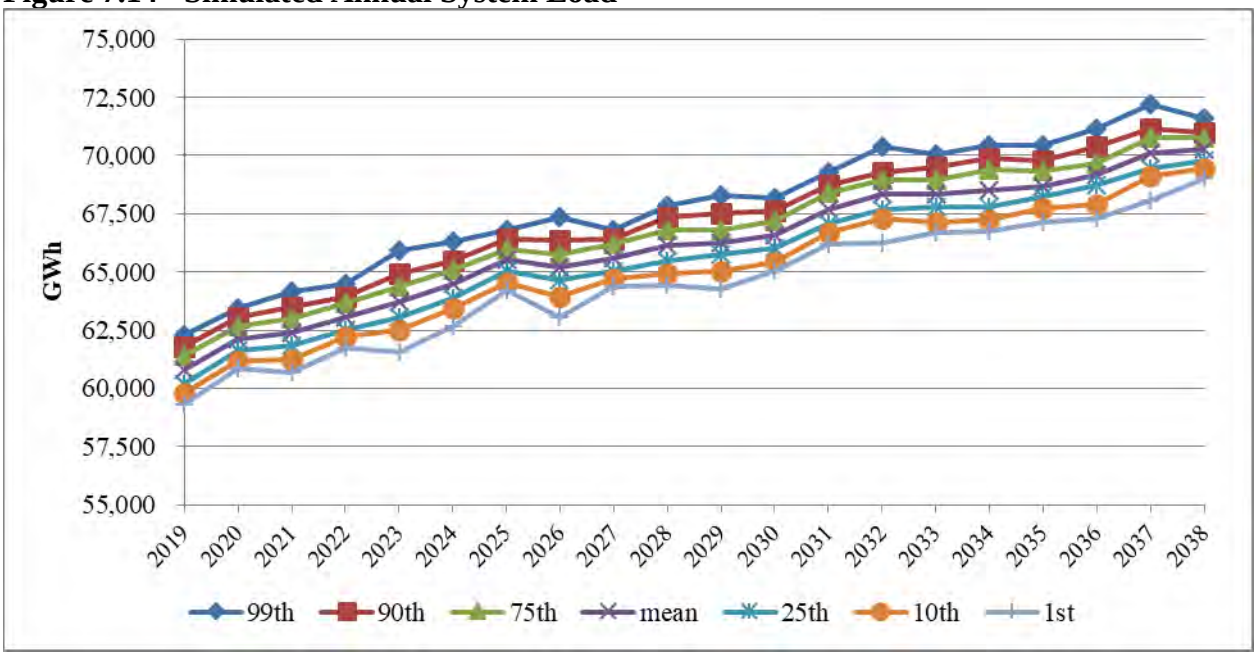
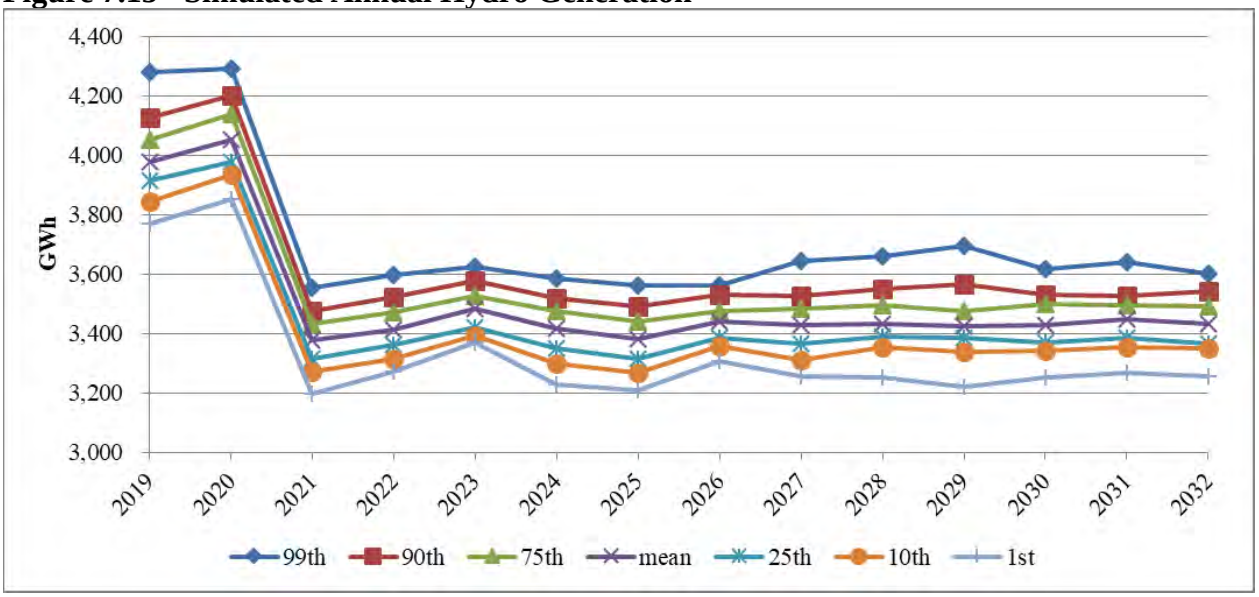


Figure 7.15 shows hydro generation at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. PacifiCorp can dispatch its hydro generation on a limited basis to meet load and reserve obligations. The parameters developed for the hydro stochastic process approximate the volatility of hydro conditions as opposed to variations due to dispatch. The drop in 2021 is due to the assumed decommissioning of the Klamath River projects. Annual differences in hydro generation between the first and 99th percentiles range from 253 GWh to 512 GWh.

Figure 7.15 - Simulated Annual Hydro Generation



Monte Carlo Simulation

During model execution, the PaR 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 of the resource portfolios being analyzed. In the case of natural gas prices, electricity prices, and regional loads, the PaR model applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

For the 2019 IRP, PaR is configured to conduct 50 Monte Carlo iterations for the 20-year study period. For each of the 50 Monte Carlo iterations, PaR generates a set of natural gas prices, electricity prices, loads, hydroelectric generation and thermal outages. Then, the model optimizes resource dispatch to minimize costs while meeting load and wholesale sale obligations subject to operating and physical constraints. In a 50-iteration simulation, the resource portfolio is fixed. The end result of the Monte Carlo simulation is 50 production cost figures for the 20-year study period reflecting a wide range of cost outcomes for the portfolio.

The expected values of the Monte Carlo simulation are the average result of all 50 iterations. Results from subsets of the 50 iterations are also summarized to capture particularly adverse cost conditions, and to derive associated cost measures as indicators of high-end portfolio risk. These cost measures, and others are used to assess portfolio performance, which are described below.

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 PaR include:

- Stochastic mean PVRR;
- Risk-adjusted mean PVRR;
- Upper-tail Mean PVRR;
- 5th and 95th percentile PVRR;
- Average annual mean and upper-tail energy not served (ENS);
- Loss of load probability; and
- Cumulative CO_2 emissions.

<u>Stochastic Mean PVRR</u>

The stochastic mean PVRR is the average of system net variable operating costs among 50 iterations, combined with the real levelized capital costs and fixed costs taken from the SO model for any given resource portfolio.[6] The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, unit start-up, market contracts, system balancing market purchases expenses and sales revenues, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources, taken from the SO model, are calculated on an escalated real-levelized basis. Other components in the stochastic mean PVRR include fixed costs for new DSM resources in the portfolio, also taken from the SO model, and CO_2 emission costs for any scenarios that include a CO_2 price assumption.

[6] Fixed costs are not affected by stochastic variables, and therefore, do not change across the 50 PaR iterations.

Risk-Adjusted PVRR

The risk-adjusted PVRR incorporates the expected-value cost of low-probability, high cost outcomes. This measure is calculated as the PVRR of stochastic mean system variable costs plus five percent of system variable costs from the 95th percentile. The PVRR of system fixed costs, taken from the SO model, are then added to this system variable cost metric. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on 50 Monte Carlo simulations for each resource portfolio. The rationale behind the risk-adjusted PVRR is to have a consolidated stochastic cost indicator for portfolio ranking, combining expected cost and high-end cost risk concepts.

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 real levelized fixed costs, taken from the SO model, are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

95th and 5th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 50 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 50 Monte Carlo iterations. The production cost is expressed as a net present value of annual costs over the period 2019 through 2038. 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.

Average and Upper-Tail Energy Not Served

Certain iterations of a stochastic simulation will have ENS, a condition where there are insufficient resources, inclusive of system balancing purchases, available to meet load or operating reserve requirements because of physical constraints. This occurs when Monte Carlo draws of stochastic variables result in a load obligation that is higher than the capability of the available resources in the portfolio. For example, this might occur in Monte Carlo draws with large load shocks concurrent with a random unplanned plant outage event. Consequently, ENS, when averaged across all 50 iterations, serves as a measure of reliability that can be compared among resource portfolios. PacifiCorp calculates an average annual value over the 2019 through 2038 planning horizon as well as the upper-tail ENS (average of the three iterations with the highest ENS). In the 2019 IRP, ENS is nominally priced at $1,000/MWh.

Loss of Load Probability

Loss of load probability (LOLP) reports the probability and extent that available resources of a portfolio cannot serve load during the peak-load period of July in the 20-year period. PacifiCorp reports LOLP statistics, which are calculated from ENS events that exceed threshold levels.

Cumulative CO_2 Emissions

Annual CO_2 emissions from each portfolio are reported from PaR and summed for the twenty year planning period. Comparison of total CO_2 emissions is used to identify potential outliers among resource portfolios that might otherwise be comparable with regard to expected cost, upper-tail cost risk, and/or ENS.

Forward Price Curve Scenarios

Top-performing resource portfolios developed with the SO model during the portfolio-development process are analyzed in PaR with up to four price-policy scenarios. The price curve scenarios are developed from PacifiCorp's September 2018 OFPC. PaR results using each of these scenarios inform selection of the preferred portfolio.

Price assumptions for each of these scenarios are subject to short-term volatility and mean reversion stochastic parameters when used in PaR. The approach for producing wholesale electricity and natural gas price scenarios used for PaR simulations is identical to the approach used to develop price scenarios for the portfolio-development process.

Other PaR Modeling Methods and Assumptions

Transmission System

The base transmission topology used for the SO model, shown in Figure 7.2, is identical to the transmission topology used for PaR simulations. Any transmission upgrades selected by the SO model that provide incremental transfer capability among bubbles in this topology are also included in PaR.

Resource Adequacy

The resource portfolio developed with the SO model, which meets an assumed 13 percent target planning reserve margin, is fixed in all PaR simulations. With fixed resources, the unit commitment and dispatch logic in PaR accounts for operating reserve requirements. These reserve requirements include contingency reserves, which are calculated as 3 percent of load and 3 percent of generation. In addition, PaR reserve requirements account for regulation reserves. PacifiCorp's regulation reserve assumptions are outlined in PacifiCorp's flexible reserve study, provided in Volume II, Appendix F (Flexible Reserve Study), including PaR's use in the reliability assessment phase of the portfolio-development process.

Energy Storage Resources

Given the complexity of PacifiCorp's system, the PaR model experienced difficulty optimizing the dispatch for battery storage resources. To improve upon this shortcoming in the PaR model, PacifiCorp developed and tested a method to produce an optimized peak-shave/valley-fill profile for these resource outside of PaR that is based on load net of wind, solar, energy efficiency resources, and private generation resources in any given portfolio. Fixed hourly dispatch, charging, and operating reserves

are entered as inputs to PaR. This methodological enhance was presented and discussed with stakeholders at the March 21, 2019 IRP public-input meeting.

General Assumptions

The general assumptions applied in the SO model for the study period (20-years beginning 2019) annual inflation rates (2.28 percent), and discount rates (6.92 percent) are also applied in PaR.

Other Cost and Risk Considerations

In addition to reviewing stochastic PVRR, ENS, and CO_2 emissions data from PaR, 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 FOTs.

Customer Rate Impacts
To derive a rate impact measure, PacifiCorp computes the percentage 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 stochastic production cost results from PaR and capital costs reported by the SO model on a real levelized basis. The real levelized capital costs are adjusted to nominal dollars consistent with the timing of when new resources are added to the portfolio. 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 develops a series of portfolios designed to quantify the risk associated with relying on FOTs for a given portfolio. These studies apply a price scalar to market prices in the peak months of July, August, and December. In the SO model, FOTs include a premium to capture the risk of price spikes where the magnitude of these price spikes are based upon the variance between historical forward prices and actual prices from an historical period. This approach, which captures the severity and volume of potential high-price hours while maintaining the shape of the underlying price curve.

Portfolio Selection

The final action in each modeling and evaluation step is portfolio selection. In the first step, to performing portfolios are identified based on their relative performance with regard to mean system costs, risk-adjusted system costs, which account for upper tail stochastic risk, reliability metrics and cumulative CO_2 emissions.

Additional refined analysis is performed on these cases to ensure there relative cost and risk metrics are comparable by performing more granular reliability analysis that also better captures potential cost savings of combining battery storage resources with solar resources. Additional analysis can be performed to further assess the relative differences among top-performing portfolios.

Within each step, each portfolio that is under examination is compared on the basis of cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include the mean PVRR, upper-tail PVRR, risk-adjusted PVRR, mean ENS, upper-tail ENS, and emissions. As noted above, market reliance risk was also evaluated and quantified. The comparisons of outcomes are detailed, ranked and assessed in the next chapter.

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 2019 IRP this included additional analysis to assess market price risk, the impact of relying on new natural gas resources, and additional studies to assess incremental transmission investments that cannot be adequately captured in the improved endogenous transmission upgrade methodology discussed earlier in this chapter and in Chapter 6 (Resource Options).

During the final screening process, the results of any further resource portfolio developments are ranked by risk-adjusted mean PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the four price-policy price curve scenarios. Resource portfolios with the lowest risk-adjusted mean PVRR receive the highest rank. Final screening also considers system cost PVRR data from the SO model and other comparative portfolio analysis. At this stage, PacifiCorp reviews additional stochastic metrics from PaR looking to identify if expected and ENS results and CO_2 emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted mean PVRR basis.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2019 IRP, organized here into major development categories:

- Coal Studies
- Portfolio Development Cases
    - Initial portfolio cases
    - C-series cases
    - CP-series cases
    - FOT cases
- Preferred Portfolio Selection

  - No new gas cases
  - Energy Gateway Transmission cases
  - Dave Johnston wind alternative
- Sensitivity Cases

Additional detail for all portfolios can be found in Volume II, Appendix M (Case Study Fact Sheets).

Coal Studies

The coal study cases are described in detail in Volume II, Appendix R (Coal Studies). Results from the coal studies informed the portfolio-development phase of the 2019 IRP by driving coal retirement assumptions in the initial portfolio development step of the portfolio-development process.

Portfolio Development Cases

Informed by the public-input process and focused on the retirement outcomes of the coal studies, these cases build diversity around varying key retirement dates, and implement modeling refinements to improve results and test evolving outcomes through the IRP process.

Initial Portfolio Cases

As informed by the Coal Studies, the over half of initial portfolios explore variations in retirement timing for Jim Bridger Units 1 and 2 and Naughton Units 1 and 2. The initial portfolios also explore potentially significant interactions with additional retirement options including the potential to convert Naughton Unit 3 to natural gas, potential tradeoffs to retire Gadsby steam units early, and the timing of other coal unit retirements that were not a focus of the Coal Study (i.e., Cholla Unit 4 and jointly owned facilities where PacifiCorp is not the operator). 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 of the initial portfolios include the new reliability assessment phase of portfolio development that was incorporated in the 2019 IRP cycle.

Table 7.9 provides the initial portfolio definitions for this IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Volume II, Appendix M (Case Study Fact Sheets).

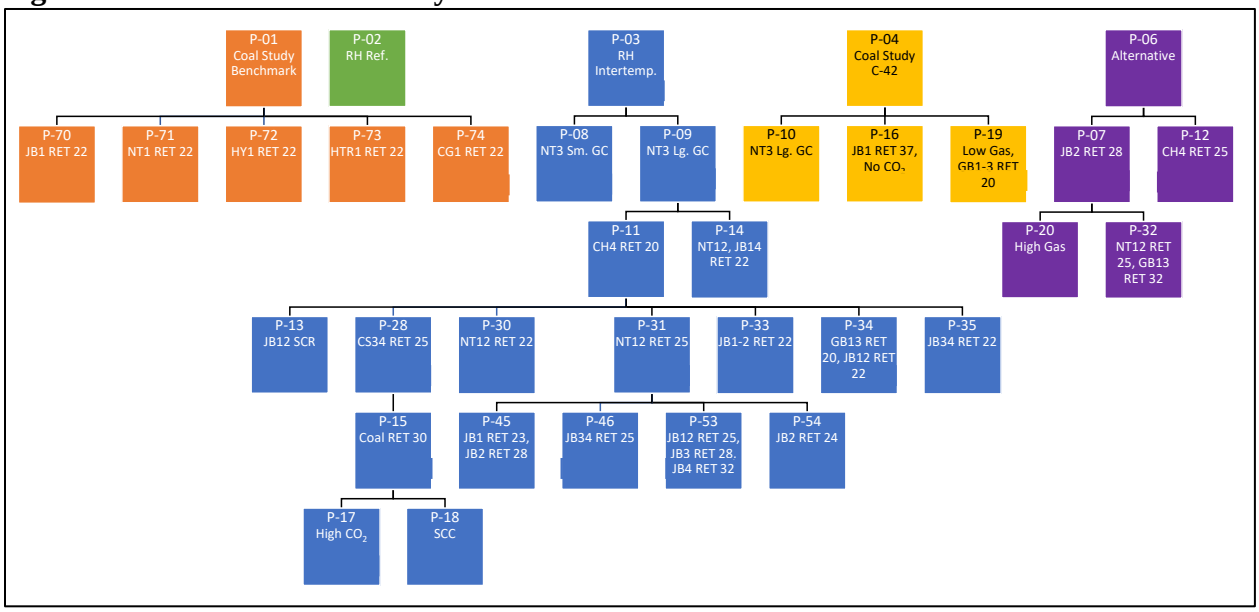
Table 7.9 – Initial Portfolio Case Definitions

Case	Description	Parent Case
P-01	Coal Study Benchmark	-
P-02	Regional Haze Reference	-
P-03	Regional Haze Intertemporal	-
P-04	Coal Study C-42	-
P-06	Gadsby Alternative Case	-
P-07	Gadsby Alternative Case	P-06
P-08	Naughton 3 Small Gas Conversion	P-03
P-09	Naughton 3 Large Gas Conversion	P-03
P-10	Naughton 3 Large Gas Conversion	P-04
P-11	Cholla 4 Retirement 2020	P-09
P-12	Cholla 4 Retirement 2025	P-06
P-13	Jim Bridger 1&2 SCRs	P-11
P-14	Naughton 1&2 and Jim Bridger 1-4 Retirement 2022	P-09
P-15	Retire All Coal by 2030	P28
P-16	Jim Bridger 1&2 Retirement 2022, No CO_2	P04
P-17	High CO_2	P-15
P-18	Social Cost of Carbon	P-15
P-19	Low Gas	P-04
P-20	High Gas	P-07
P-28	Colstrip 3&4 Retirement 2025	P-11
P-30	Naughton 1&2 Retirement 2022	P-11
P-31	Naughton 1&2 Retirement 2025	P-11
P-32	Naughton 1&2 Retirement 2025 with Gadsby 1-3 Retirement 2032	P-07
P-33	Jim Bridger 1&2 Retirement 2022	P-11
P-34	Jim Bridger 1&2 Retirement 2022, with Gadsby 1-3 Retirement 2020)	P-11
P-35	Jim Bridger 3&4 Retirement 2022	P-11
P-45	Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2038	P-31
P-46	Jim Bridger 3&4 Retirement 2025	P-31
P-53	Jim Bridger 1&2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032	P-31
P-54	Jim Bridger 2 Retirement 2024	P-31

Initial portfolio case refinements and additions were modeled on the basis of outcomes and stakeholder feedback throughout the 2019 IRP public-input process. This led to the developing assumptions for many cases as a variant from another case, lending itself to a "family tree" structure as a means to describe the relationship among cases. Figure 7.16 summarizes the case definitions in this family tree format. Note, cases P-70 through P-74 were developed in response to stakeholder interest to reaffirm Coal Study findings that early retirement of units at the Naughton and Jim Bridger plant were most likely to generate cost savings. These cases were higher cost than most of the other cases and were not evaluated as potential candidates for the preferred portfolio. The top row of cases in this figure represent "parent cases" from which all other cases were

derived. The text in each box of the family tree describes what changed relative to the case from which it was derived (i.e., case P-08 retains all attributes of case P-03, except case P-08 assumes a small gas conversation at Naughton Unit 3 in 2020).

Figure 7.16 – Initial Case Family Tree



C-Series Cases

In the C-series, top-performing portfolios from the initial portfolio cases were examined with additional deterministic test years used to ascribe reliability resources covering 2023 through 2030, plus 2038. This provides a total of nine years of hourly PaR reliability assessment rather than the three years (2023, 2030, and 2038) employed in the initial portfolio cases.

When reliability resources are added in the two-step portfolio development process adopted for this IRP cycle, incremental battery resources are routinely added to remedy initial reliability shortfalls in each case. This indicates that if the SO model were able to assess the incremental reliability requirement in its *initial* resource portfolio, it would likely pair batteries with any of the new solar resources it initially added to take advantage of cost savings for this combined resource alternative.

Test runs performed by the IRP modeling team confirmed that if stand-alone solar resources were not allowed in the initial portfolio development case, that the SO model selected solar+battery combination resource options, and that when these portfolios were analyzed for reliability (using the additional test years as described above) and run through the PaR model, the overall system PVRR was lower.

Consequently, for the five cases with the lowest system PVRR from the initial step of the portfolio-development process and for additional cases developed after stakeholder discussion at the September 2019 public-input meeting, PacifiCorp disabled stand-alone solar resources—in each case, solar+battery is added to the portfolio and system costs were reduced.

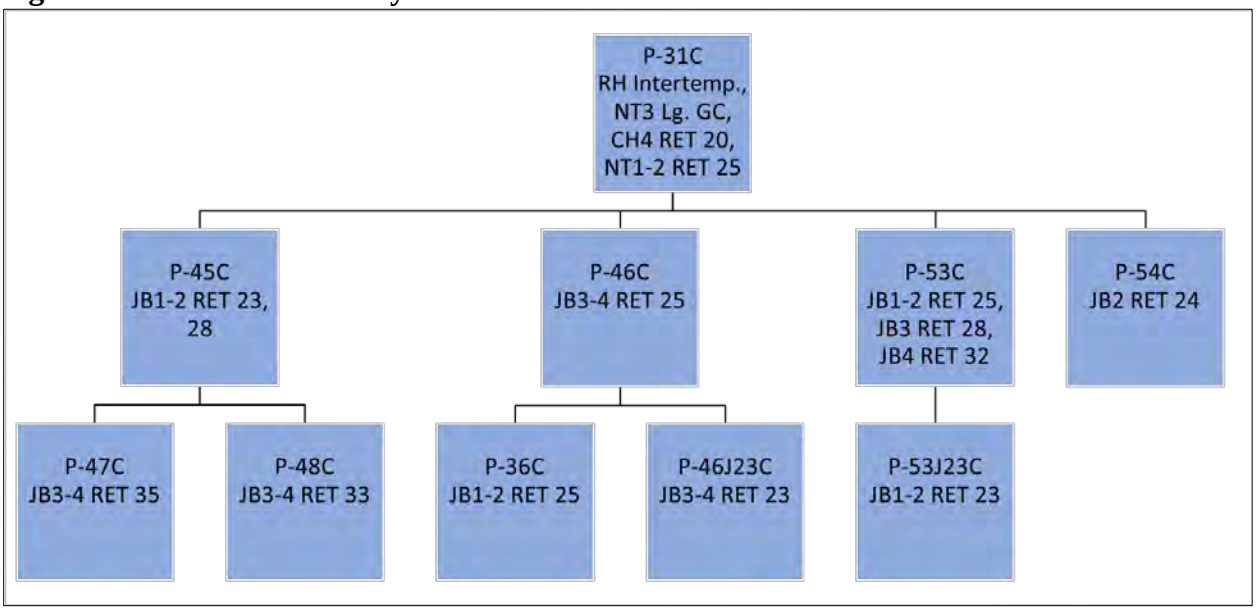
In addition to the five top performing cases derived from the initial portfolios (P-31C, P-45C, P-46C, P-53C and P-54C), the C-series includes five additional cases developed after discussion at

the September 5-6, 2019 public-input meeting (P-36C, P-46J23C, P-47C, P-48C, P-53J23C). Table 7.10 provides the C-series portfolio definitions for this IRP. Figure 7.17 shows the family tree relationship for the C-series of cases.

Table 7.10 – C-Series Case Definitions

Case	Description (Change from Parent Case)	Parent Case
P-31C	Naughton 1-2 Retire 2025	P-11
P-36C	Jim Bridger 1-2 Retire 2025	P-46
P-45C	Jim Bridger 1 & 2 Retire 2023 and 2038	P-31
P-46C	Jim Bridger 3 & 4 Retire 2025	P-31
P-46J23C	Jim Bridger 3 & 4 Retire 2023	P-46
P-47C	Jim Bridger 3 & 4 Retire 2035	P-45
P-48C	Jim Bridger 3 & 4 Retire 2033	P-45
P-53C	Jim Bridger 1 & 2 Retire 2025, Jim Bridger 3-4 Retire 2028/2032	P-31
P-53J23C	Jim Bridger 1 & 2 Retire 2023	P-53
P-54C	Jim Bridger 2 Retire 2024	P-31

Figure 7.17 – C-Series Family Tree



CP-Series Cases

In the CP-series[7], top-performing portfolios informed by the C-series cases are examined with additional deterministic years covering 2023 through 2038. This provides a total of 16 years of hourly PaR reliability assessment, and fleshes out any granular variances driven by mapping results from a single reliability test year to multiple simulation years in the back-end of the study period.

Table 7.11 provides the CP-series portfolio definitions for this IRP. While the P-54C, P-54J23C, and P-31C cases were not evaluated in the CP-series, the family tree relationships for the cases in the table below are unchanged from the family tree relationships depicted for the C-series of cases.

[7] "CP" refers to "C-Prime", an expansion of the deterministic runs used for reliability assessment in the C-Series cases.

Table 7.11 – CP-Series Case Definitions

Case	Description (Change from Parent Case)	Parent Case
P-36CP	Jim Bridger 1-2 Retire 2025	P-46
P-45CP	Jim Bridger 1-2 Retire 2023 and 2038	P-31
P-46CP	Jim Bridger 3 & 4 Retire 2025	P-31
P-46J23CP	Jim Bridger 3 & 4 Retire 2023	P-46
P-47CP	Jim Bridger 3 & 4 Retire 2035	P-45
P-48CP	Jim Bridger 3 & 4 Retire 2033	P-45
P-53CP	Jim Bridger 1 & 2 Retire 2025, Jim Bridger 3-4 Retire 2028/2032	P-31

Front Office Transaction (FOT) Portfolios

PacifiCorp ran a series of FOT studies designed to quantify the impact and risk of market reliance for a given portfolio. These cases use an escalating scalar to elevate market prices during the peak months of July, August and December of every study year. As FOT prices are calculated as market price plus a premium, FOT prices are elevated with the market.

The scalar targets a maximum escalation based on the largest difference between each month's highest Mid-C forward price and the highest Mid-C historical price in the sample year of 2018. This yields a maximum peak scalar of 3.72 times higher than the forward price curve in the month of August; 3.70 times higher in the month of July; and 1.77 times higher in the month of December. The higher the original forward price in a given hour, the higher the scalar. This has the effect of increasing both the severity and frequency of high-price hours (increases upward volatility) while maintaining the shape of the underlying price curve.

Figure 7.18 illustrates the differences between the underlying forward price curve (FPC) and the escalating scaled price curve in each peak month in the sample year 2021.

Figure 7.18 – Sample Year 2021 FOT MidC FPC and Scaled Price Curves

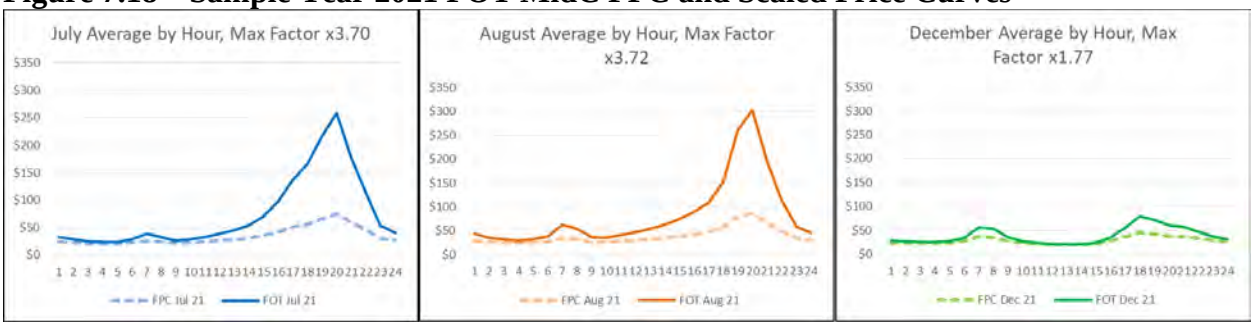


Table 7.12 lists the CP-series of cases where for which FOT scenarios were developed to evaluate market-reliance risk.

Table 7.12 – Front Office Transaction (FOT) Case Definitions

Case	Description
P-45CP-FOT	P-45CP with FOT price curve
P-46CP-FOT	P-46CP with FOT price curve
P-47CP-FOT	P-47CP with FOT price curve
P-48CP-FOT	P-48CP with FOT price curve
P-53CP-FOT	P-53CP with FOT price curve

2028-2029 Wyoming Wind Case

In reviewing CP-series case results, PacifiCorp identified that 620 MW of Wyoming wind resources added to each portfolio in the 2028-2029 timeframe, which coincides with the assumed retirement of Dave Johnston, were being curtailed at relatively significant levels. Consequently, and considering it unreasonable to potentially include highly curtailed new wind in a leading candidate for the preferred portfolio, PacifiCorp produced an incremental portfolio as a variant of the least cost CP-series case (P-45CP) that eliminated the 620 MW of incremental Wyoming wind coming online after the retirement of Dave Johnston. This case is referred to as P-45CNW.

Preferred Portfolio Selection Cases

Certain additional cases were developed directly from the top-performing case (P-45CNW) based on analysis of portfolios from the initial cases through the CP-series of 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 2019 IRP, there are two types of preferred portfolio selection cases:

- No Gas portfolios
- Gateway portfolios (excluding gateway south, which is modeled as an option in all cases)

"No Gas" Cases

PacifiCorp ran two cases as variants of P-45CNW to evaluate portfolio impacts of excluding new natural gas capacity from the portfolio. The first case, P-29 does not allow the model to select new natural gas resources (excluding the Naughton Unit 3 gas conversion). The second case, P-29PS is a variant of P-29 with the addition of a 400 MW pumped storage project located in northeast Wyoming that comes online in 2028 following retirement of the Dave Johnston plant. Table 7.13 provides the No-Gas case definitions for this IRP.

Table 7.13 – No Gas Case Definitions

Case	Description	Parent Case
P-29	P-45CNW, No New Gas Option	P-45CNW
P-29 PS	P-45CNW, No New Gas Option with pumped hydro storage	P-45CNW

Gateway Cases

PacifiCorp modeled four Energy Gateway transmission cases, expanding on scenarios defined in previous IRP cycles. The full build-out of all Energy Gateway segments was performed in two cases (P-23 and P-25) to assess the potential value in two different coal retirement scenarios. The Energy Gateway cases developed for the 2019 IRP are summarized in Table 7.14 and Table 7.15.

Table 7.14 – Additional Gateway Case Definitions

Case	P-22	P-23	P-25	P-26
Base Case	P-45CNW	P-36CNW	P-45CNW	P-45CNW
Segments*	(D3), (F)	(D3), (E), (F), (H)	(D3), (E), (F), (H)	(F), (H)

Table 7.15 – Gateway Segment Definitions

Segment	Description	Incremental Capacity	Approximate Mileage	Build Year
(D3) Bridger/Anticline - Populus	500 kV single circuit	1700 MW + PathC 1000 MW	200 mi	2025
(E) Populus - Hemingway	500 kV single circuit	1260 MW	500 mi	2025
(F)* Aeolus - Clover	500 kV single circuit	1700 MW	400 mi	2023
(H) Boardman - Hemingway	500 kV single circuit	600 MW	290 mi	2026

* Note: Energy Gateway South Segment F is modeled as an option, and is selected in each Energy Gateway case summarized above.

Sensitivity Case Definitions

PacifiCorp initially identified 8 sensitivities based on prior IRP cycle experience, stakeholder feedback, and anticipated areas of interest. Each sensitivity is designed to highlight the impact of specific planning assumptions on future resource selections along with the associated impact on system costs and stochastic risks. These sensitivities were developed for informational purposes and serve to illustrate how the system behaves under a variety of conditions which helps inform the acquisition path analysis presented in Volume 1, Chapter 9 (Action Plan). All sensitivities, as summarized in Table 7.16, were run as a variant of case P-45CNW. Additional details on the sensitivity cases can be found in Volume II, Appendix M: Case Study Fact Sheets.

Table 7.16 – Sensitivity Case Definitions

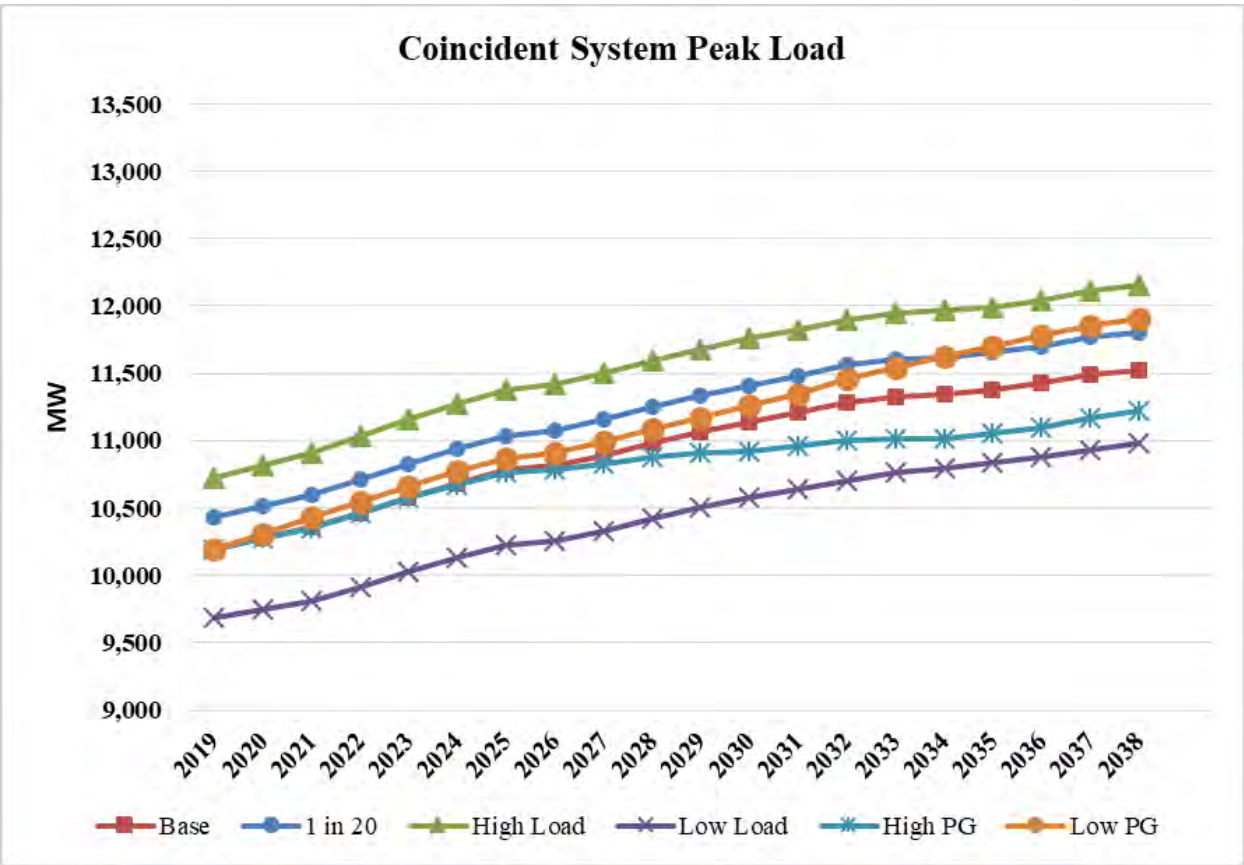
Case	Description	Load Forecast	Private Generation	Resources	Customer Preference	SO Model CO2 Price
S-01	Low Load	Low	Base	Optimized	Base	Base
S-02	High Load	High	Base	Optimized	Base	Base
S-03	1 in 20 Load Growth	1 in 20	Base	Optimized	Base	Base
S-04	Low Private Generation	Base	Low	Optimized	Base	Base
S-05	High Private Generation	Base	High	Optimized	Base	Base
S-06	Business Plan	Base	Base	Align first three years	Base	Base
S-07	No Customer Preference	Base	Base	Optimized	No targeted renewables	Base
S-08	High Customer Preference	Base	Base	Optimized	High	Base

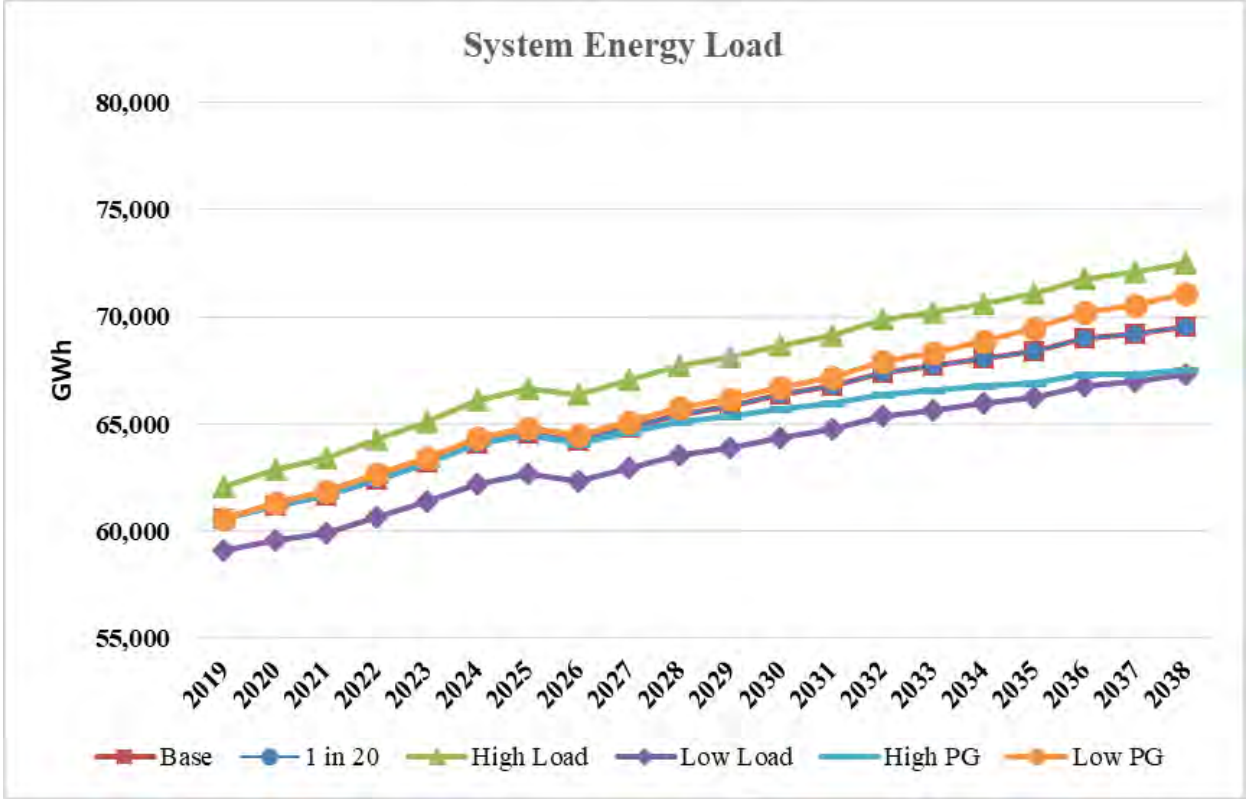
Load Sensitivities

PacifiCorp includes three different load forecast sensitivities. The low load forecast sensitivity (S-01) reflects pessimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The high load forecast sensitivity (S-02) reflects optimistic economic growth assumptions from IHS Global Insight and high Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The low and high industrial load forecast is taken from 5th and 95th percentile.

The third load forecast sensitivity (S-03) 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 7.19 compares the low, high, and 1-in-20 load sensitivities, net of base case private generation levels, alongside the base case load forecast.

Figure 7.19 - Load and Private Generation Sensitivity Assumptions

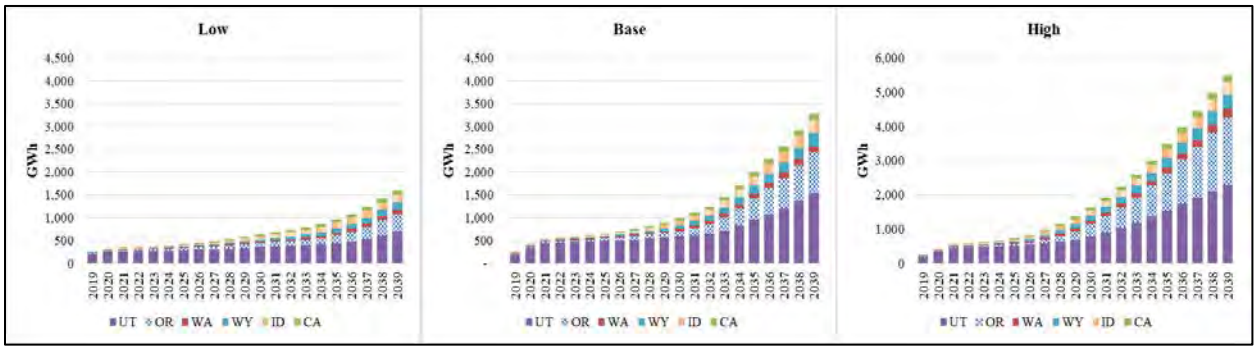




Private Generation Sensitivities

Two private generation sensitivities are analyzed. As compared to base private generation penetration levels that incorporated annual reductions in technology costs, the low private generation sensitivity (S-04) reflects lesser reductions in technology costs, reduced technology performance levels, and lower retail electricity rates. In contrast, the high private generation sensitivity (S-05) reflects more aggressive technology cost reduction assumptions, greater technology performance levels, and higher retail electricity rates. Figure 7.20 summarizes private generation penetration levels for the low and high sensitivities alongside the base case.

Figure 7.20 - Private Generation Sensitivity Assumptions



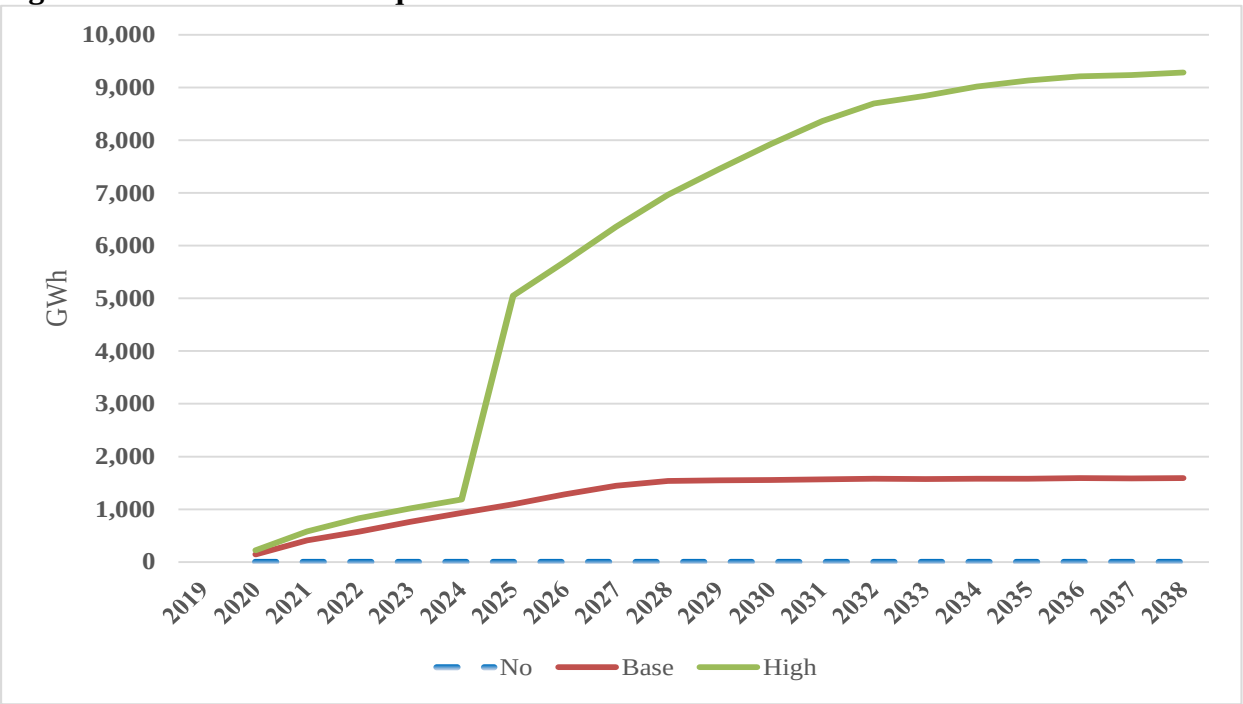
Business Plan Sensitivity

Case S-06 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 December 2018 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 within the SO model simulation.

Customer Preference Sensitivities

PacifiCorp includes two customer preference sensitivities. The first sensitivity is a no customer preference sensitivity (S-07) that assumes there are no customer preference resource requirements. The second sensitivity (S-08) is a high customer preference sensitivity that assumes proliferation of customer preference resources at higher levels than anticipated with close to 9,300 GWh of customer preference resources being added by the end of the twenty-year planning period. Figure 7.21 illustrates the relative customer preference generation requirements for these sensitivities.

Figure 7.21 – Generation Requirements for Customer Preference Sensitivities



East/West Split

Pursuant to a requirement by the Washington Utilities and Transportation Commission, PacifiCorp's IRP is to include a sensitivity that produces standalone resource portfolios for the west control area (WCA) compared to operation as part of PacifiCorp's integrated system. PacifiCorp will incorporate this sensitivity as part of its 2019 IRP Update pursuant to the Washington Utilities and Transportation Commission's July 26, 2019 order approving PacifiCorp's request for a waiver to WAC 480-100-238(4) in Docket UE-180259.

CHAPTER 8 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Using a range of cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio reflecting a bold vision shared with our customers for a future where energy is delivered affordably, reliably and without greenhouse gas emissions.
- The 2019 Integrated Resource Plan (IRP) preferred portfolio includes accelerated coal retirements and investment in transmission infrastructure that will facilitate adding over 6,400 megawatt (MW) of new renewable resources by the end of 2023, with nearly 11,000 MW of new renewable resources over the 20-year planning period through 2038.[1]
- Near-term, by the end of 2023, the preferred portfolio includes nearly 3,000 MW of new solar resources, more than 3,500 MW of new wind resources, nearly 600 MW of battery storage capacity (all collocated with new solar resources), and over 700 MW of incremental energy efficiency and new direct load control resources.[2]
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes a 400-mile transmission line known as Gateway South, planned to come online by the end of 2023, that will connect southeastern Wyoming and northern Utah. The preferred portfolio further includes near-term transmission upgrades in Utah and Washington. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources.
- Energy efficiency continues to play a key role in PacifiCorp's resource mix. In addition to continued investment in energy efficiency programs, the preferred portfolio continues to show a role for direct load control programs with total new capacity reaching 444 MW by the end of the planning period.
- Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 24 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 16 of the units by 2030 and 20 of the units by the end of the planning period in 2038. Coal unit retirements in the 2019 IRP preferred portfolio will reduce coal-fueled generation capacity by over 1,000 MW by the end of 2023, nearly 1,500 MW by the end of 2025, nearly 2,800 MW by 2030, and nearly 4,500 MW by 2038.
- In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost reliable resource for meeting load and reliability requirements. New natural gas peaking resources appear in the preferred portfolio starting in 2026, which is outside the action-plan window and provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain system reliability into the future.
- The preferred portfolio shows an overall decline in reliance on wholesale market firm purchases in the 2019 IRP preferred portfolio relative to the market purchases included in

[1] Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.
[2] *Id.*

the 2017 IRP preferred portfolio. In particular, reliance on market purchases during summer peak periods averages 366 MW per year over the 2020-2027 timeframe—down 60 percent from market purchases identified in the 2017 IRP preferred portfolio.

- The 2019 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) emissions. As compared to the 2017 IRP, projected carbon dioxide (CO_2) emissions in 2025, are down sixteen percent relative to the 2017 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2017 IRP preferred portfolio, and down 35 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.1 million tons in 2019 to 16.7 million tons in 2038—a 61.3 percent reduction.

Introduction

This chapter reports modeling and performance evaluation results for the resource portfolios developed with a broad range of input assumptions using the System Optimizer (SO) model and the Planning and Risk model (PaR). Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, PacifiCorp steps through its preferred portfolio selection process and presents the 2019 IRP preferred portfolio.

The chapter is organized around the three modeling and evaluation steps identified in the previous chapter: (1) coal studies; (2) portfolio development; and (3) preferred portfolio selection. The final preferred portfolio selection is informed by all relevant case results and incorporates any refinements indicated by preceding results, recent relevant events and stakeholder feedback. This chapter also presents modeling results for additional 2019 IRP sensitivity cases that, while informative, were not considered for selection as the preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented as PacifiCorp steps through the following discussion of its portfolio evaluation processes. Stochastic modeling results from PaR are also summarized in Volume II, Appendix L (Stochastic Simulation Results).

Coal Studies

The 2019 IRP included a thorough and robust economic analysis of PacifiCorp's coal units. The coal study analysis conducted in the 2019 IRP was initially prompted by the Public Utility Commission of Oregon (OPUC) as set forth in its 2017 IRP acknowledgement order, which administratively established certain modeling requirements. PacifiCorp met these requirements and then developed a more complete coal study. The coal study effort is comprised of the following three key phases:

- Phase One - Unit-by-unit coal studies.
- Phase Two - Stacked coal studies.
- Phase Three - Reliability coal studies.

The three phases of the coal studies are detailed in Volume II, Appendix R (Coal Studies).

Coal Studies Conclusions

Each of the coal study phases show that early retirement of certain coal units has potential to reduce overall system costs. In particular, the coal studies showed that the greatest customer benefits were most likely to be realized with potential early retirement of coal units at the Naughton and Jim Bridger coal plants located in Wyoming.

The portfolio-development process considers other planning factors not fully evaluated in the coal studies (i.e., Regional Haze compliance, alternative retirement dates for jointly owned coal plants where PacifiCorp is a minority owner and not an operator, alternative timing of potential retirements when accounting for incremental capacity to maintain reliability). Consistent with the findings from the coal study, more than half of the cases developed in the initial phase of the portfolio-development process evaluated varying combinations of retirement dates for Naughton and Jim Bridger units.

Portfolio Development

The following discussion begins with an examination of *initial portfolios* exploring variations in retirement timing for the Jim Bridger 1 & 2 and Naughton 1 & 2 units. The initial portfolios also explore potentially significant interactions with additional retirement options including possible Naughton 3 gas conversion, Gadsby gas unit retirements, and the timing of Cholla retirement.

Following the initial portfolios, PacifiCorp refines top-performing cases with two stages of additional reliability requirements, referred to as the C-series of cases and the CP-series of cases.

In the C-series of cases, top-performing portfolios are examined with a more granular assessment of reliability requirements through the production of hourly deterministic Planning and Risk Model (PaR) studies covering 2023 through 2030, plus 2038. This provides a total of nine years of hourly PaR reliability assessment rather than the three years (2023, 2030, and 2038) used to develop the initial portfolios. As described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), in addition to expanding the reliability assessment step of portfolio development the C-series also removes proxy stand-alone solar resources from the resource options available to the SO model, which lowers the present-value revenue requirement (PVRR) in all cases.

Top-performing portfolios from the C-series of cases were further examined in the CP-series of cases with additional deterministic PaR studies covering 2023 through 2038. This provides a total of 16 years of hourly PaR reliability assessment, and fleshes out any granular variances in the back-end of the study period.

As discussed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), PacifiCorp produced a variant of the top-performing CP-series case to eliminate Wyoming wind resources that were added in the 2028-2029 timeframe. This case, along with other cases from the CP-series, were further analyzed to quantify market reliance risk in a series of front office transaction (FOT) cases. Final selection cases were also developed to evaluate the impact of removing all new natural gas resource from the top-performing portfolio and to assess the impact of adding additional Energy Gateway transmission segments to the top-performing portfolio.

Initial Portfolio Development

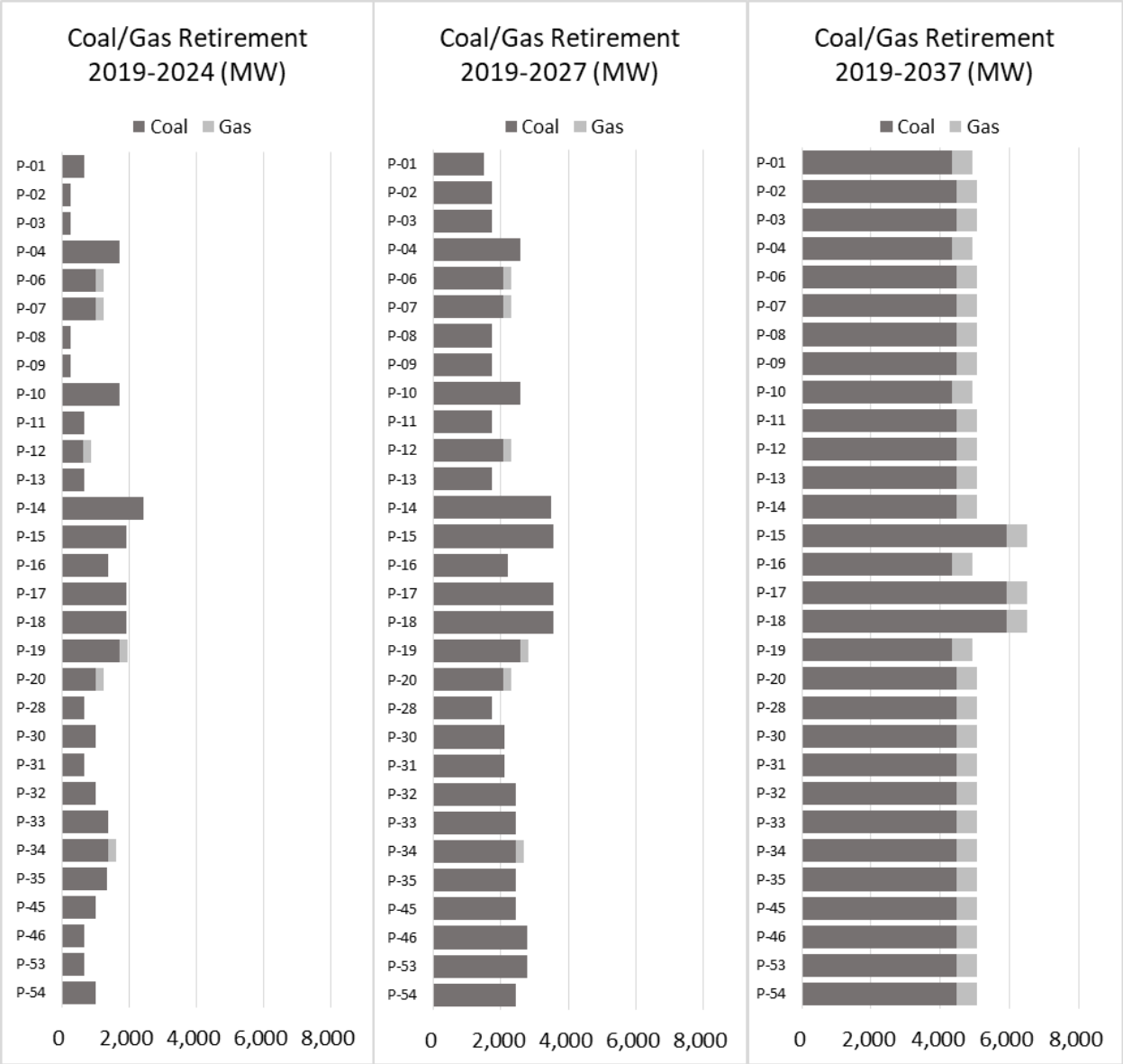
The following tables and figures present resource additions and system costs for the initial portfolios. Additional information is provided for these cases in Volume II, Appendix K (Capacity Expansion Results Detail), including detailed resource portfolio results showing new resource capacity and changes to existing resource capacity by year. Summary portfolio results are also shown in the case fact sheets presented in Volume II, Appendix M (Case Study Fact Sheets).

Coal and Gas Resource Retirements

Figure 8.1 summarizes the cumulative nameplate coal and gas retirements by case over the near-term, mid-term, and long-term among the initial portfolio cases. Note, in reporting cumulative capacity in this figure and in the similar figures that follow, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix M (Case Study Fact Sheets).

By the end of the study period, coal retirements are similar among nearly all cases (P-15, P-17 and P-18 are exceptions), with slight variations dependent upon timing for Colstrip Units 3 and 4. Cases P-15, P-17, and P-18 assume all coal is retired by the end of 2030. By the end of the study period, gas retirements are the same among all cases. Cases P-06, P-17, P-12, P-19, P-20, and P-34 assume the gas-fueled Gadsby Units 1-3 retire at the end of 2020. Among the five cases with the lowest PVRR (cases P-31, P-45, P-46, P-53, and P-54), coal unit retirements range from 667 MW to 1,023 MW through 2024 and range between 2,091 MW and 2,797 MW through the end of 2027.

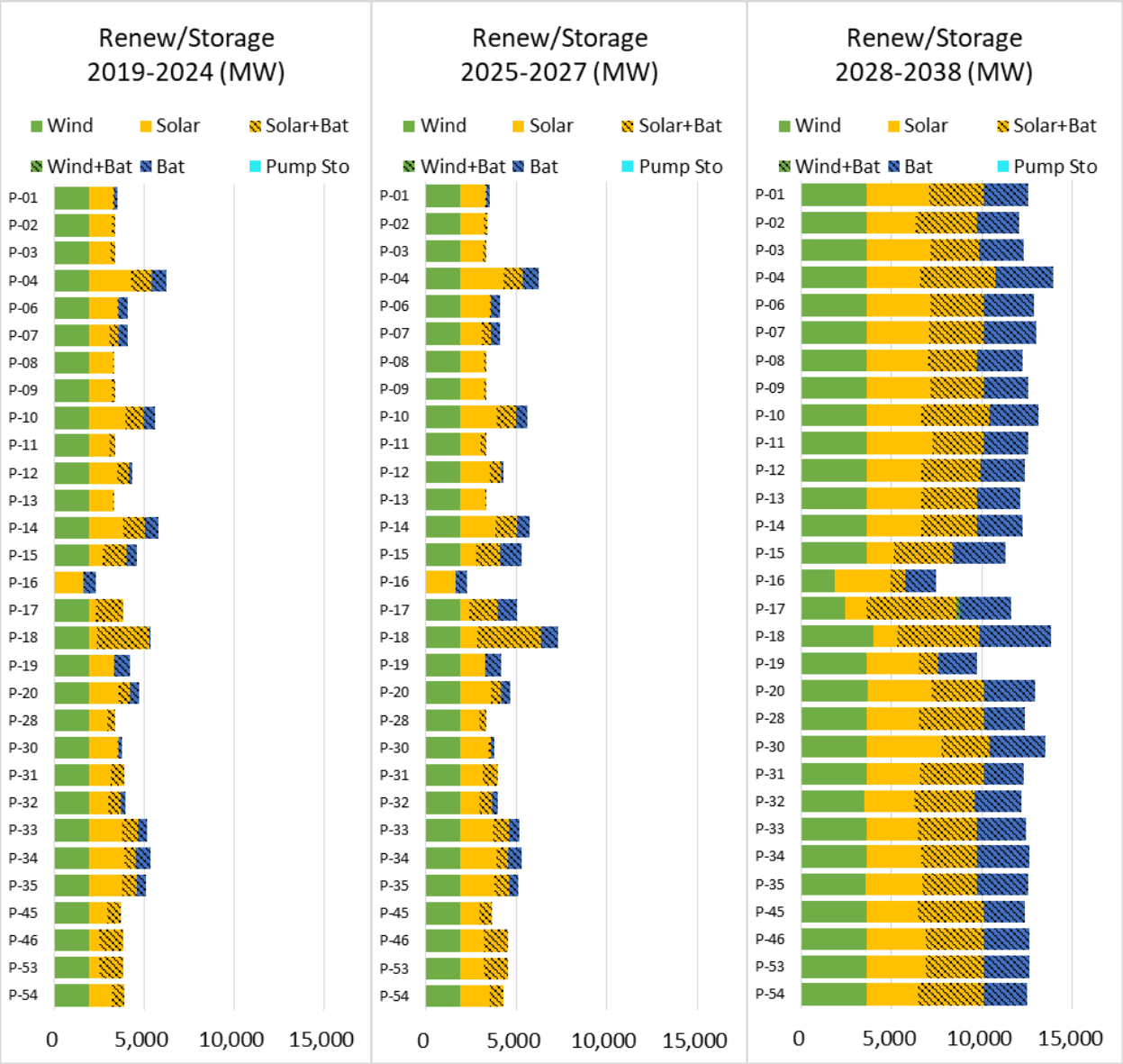
Figure 8.1 – Initial Portfolios Coal and Gas Resource Retirements Summary



New Renewable and Storage Resources

Figure 8.2 reports the nameplate capacity of new renewables and storage resource additions for each initial case. Near-term renewable additions through 2024 range from 1,633 MW to 5,475 MW. In all cases but one (case P-16, which eliminates CO_2 price assumptions through the study period), the SO model selects Energy Gateway South in 2024 (a proxy for year-end 2023) along with 1,920 MW of new wind in eastern Wyoming. Excluding case P-16, the minimum penetration of new renewable capacity is 3,290 MW through 2024 (a proxy for year-end 2023). Through the mid-term, renewable capacity grows up to 6,372 MW by 2027. Through 2027, new solar capacity ranges between 1,370 MW and 4,452 MW—cases with more early coal retirements have more solar capacity. Through 2038, the total new renewable capacity ranges between 5,574 MW and 10,711 MW, and new battery storage capacity ranges between 1,903 MW and 4,558 MW. Among the five cases with the lower PVRR (cases P-31, P-45, P-46, P-53, and P-54), the total new renewable capacity ranges between 3,674 MW and 4,536 MW through 2027 and over 10,000 MW through 2038.

Figure 8.2 – Initial Portfolios New Renewable and Storage Resources Summary

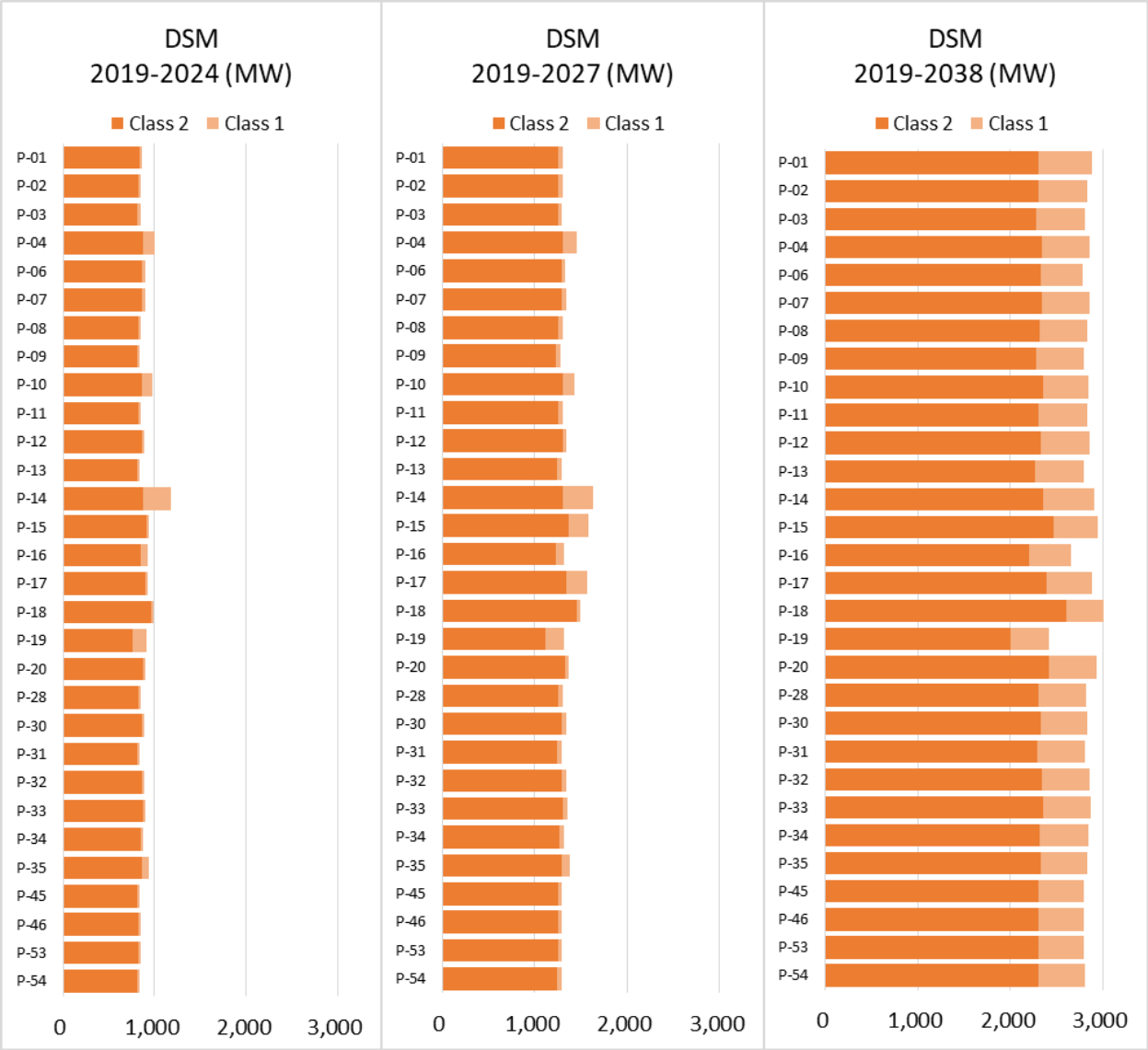


Note: For wind or renewable resources paired with battery, the capacity for the renewable resource is shown in the graph. The battery capacity paired with these resources is 25 percent of the renewable resource capacity.

Incremental Demand-Side Management (DSM)

Figure 8.3 summarizes aggregated demand-side Management (DSM) selections by case. Selected volumes of DSM are relatively stable among all initial cases. Through 2024, Class 2 DSM (energy efficiency) selections range between 763 MW (case P-19) and 965 MW (case P-18) and Class 1 DSM (demand response and direct-load control) ranges between 11 MW and 19 MW. Through 2027, Class 2 DSM selections range between 1,116 MW (case P-19) and 1,455 MW (case P-18) and Class 1 DSM ranges between 45 MW and 322 MW. More Class 1 DSM resources are accelerated into the mid-term among those cases that have higher levels of accelerated coal and gas retirements (cases P-04, P-10, P-14, P-15, P-16, P-17 and P-19). Through 2038, Class 2 DSM selections range between 2,005 MW (case P-19) and 2,603 MW (case P-18) and Class 1 DSM ranges between 417 MW and 583 MW.

Figure 8.3 – Initial Portfolios Incremental DSM Summary



New Natural Gas Resources

Figure 8.4 summarizes cumulative natural gas expansion resources for each initial portfolio. In cases where Naughton Unit 3 converts to natural gas in 2020, it is assumed to retire at the end of 2029, so it does not show up in the results through 2038. Four cases (P-14, P-16, P-17, and P-19) include new gas peaking capacity in 2023. Through 2038, new peaking gas capacity ranges between 813 MW and 2,458 MW. Case P-15 includes new combined-cycle combustion turbine (CCCT) gas capacity beginning 2027—through 2038, new CCCT capacity in this case totals 1,541 MW. Three additional cases include CCCT capacity, albeit at reduced levels relative to case P-15 (cases P-16, P-17 and P-19). Among the five cases with the lowest PVRR (cases P-31, P-45, P-46, P-53, and P-54), new peaking gas capacity is added in 2026 (185 MW)—by 2038, new gas peaking capacity totals 1,367 MW.

Figure 8.4 – Initial Portfolios New Natural Gas Resources

- Note: Scale change in the 'through 2038' column due to P15's addition of CCCT resources.

Summer Front Office Transactions (FOT)

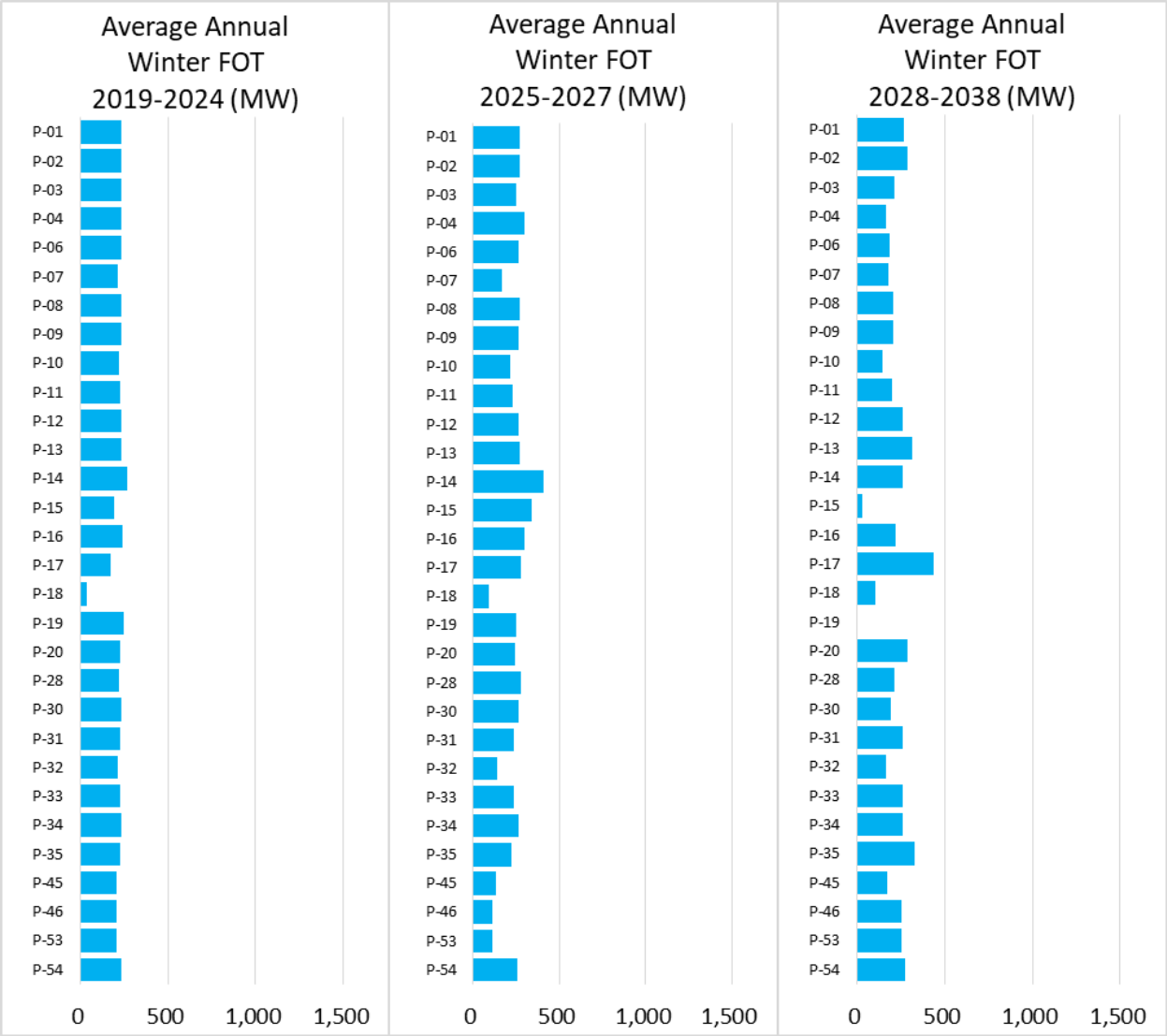
Figure 8.5 summarizes the average of FOTs for each initial portfolio during the summer peak. The summer FOT limit assumed for the 2019 IRP is 1,425 MW. Through the near-term, average annual summer FOT purchases range between 543 MW (cases P-46 and P-53) and 1,031 MW (case P-19). In the 2025-2027 timeframe, a period where there are resource-adequacy concerns in the region, summer average annual FOT purchases range between 168 MW (case P-31) and 1,290 MW (case P-16)—reliance on the market grows in cases with more accelerated coal retirements. Over the long term, the level of summer FOTs is relatively stable among all cases, ranging between 1,241 MW (Case P-13) and 1,362 MW (Case P-15).

Figure 8.5 – Initial Portfolios Summer Front Office Transactions Summary

Winter Front Office Transactions

Figure 8.6 summarizes the average of FOTs for each initial portfolio during the winter peak. The winter FOT limit assumed for the 2019 IRP is 1,425 MW. Relative to the summer period, winter FOTs are much smaller among all cases and timeframes. Winter FOT purchases are also relatively stable among most cases through both the short and mid-term. Over the long term, winter FOT purchases are reduced when incremental capacity is added to the system—CCCT additions in P-15 and P-19 significantly reduce winter FOT purchases.

Figure 8.6 – Initial Portfolios Winter Front Office Transactions Summary



CO_2 Emissions

Figure 8.7 reports cumulative CO_2 emissions for each initial portfolio. Total CO_2 emissions through 2022 are very stable, ranging between 162 and 164 million tons. Through 2027, total CO_2 emissions range between 318 and 353 million tons. Through 2038, total CO_2 emissions range between 427 and 670 million tons. Among the five cases with the lowest PVRR (cases P-31, P-45, P-46, P-53, and P-54), total CO_2 emissions through 2038 range between 560 and 588 million tons.

Figure 8.7 – Initial Portfolios CO_2 Emissions Summary

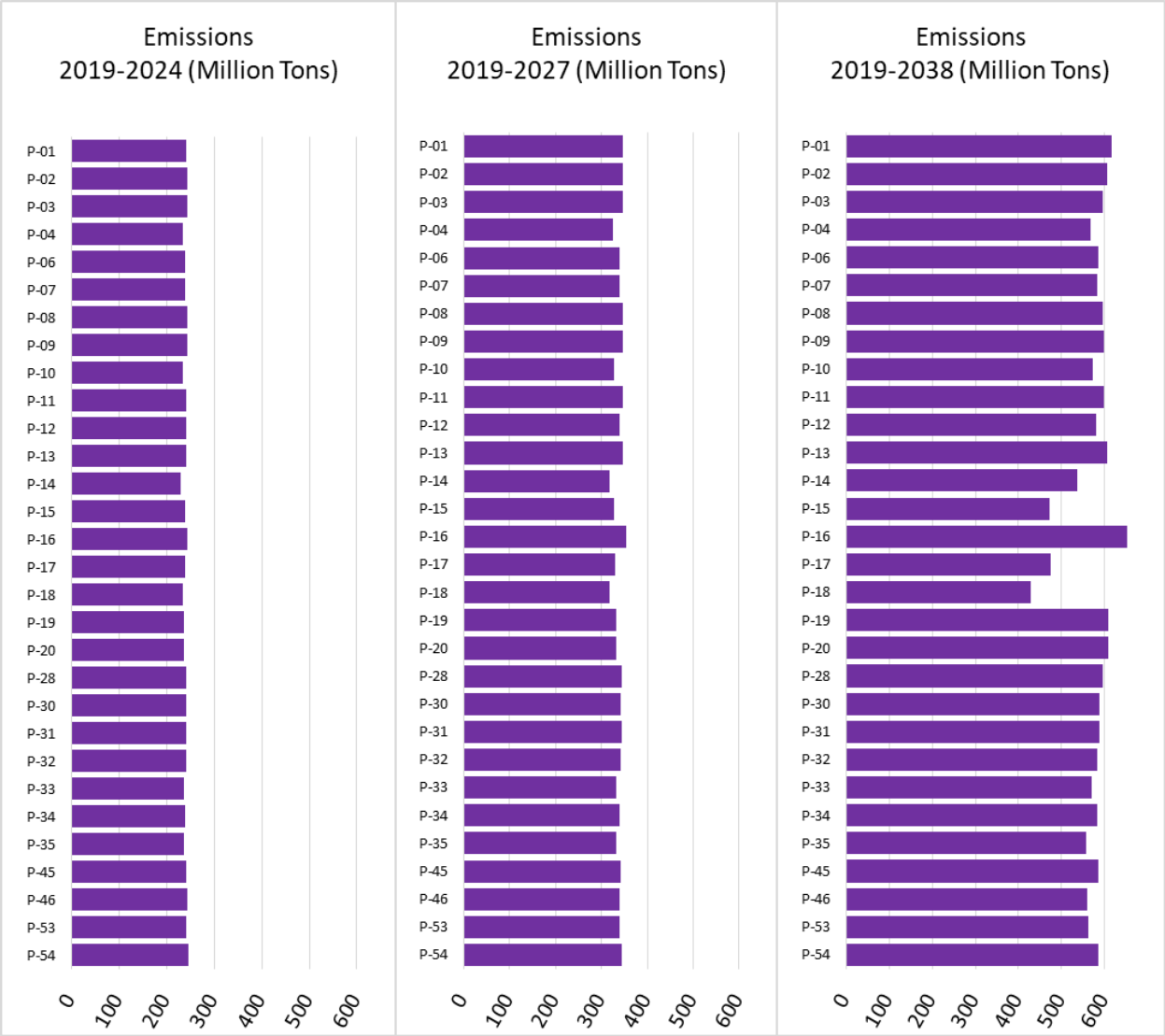


Table 8.1 summarizes results for the initial portfolios, including the stochastic mean PVRR, the risk-adjusted PVRR, amount of energy not served (ENS) as a percentage of load, and CO_2 emissions for each case.

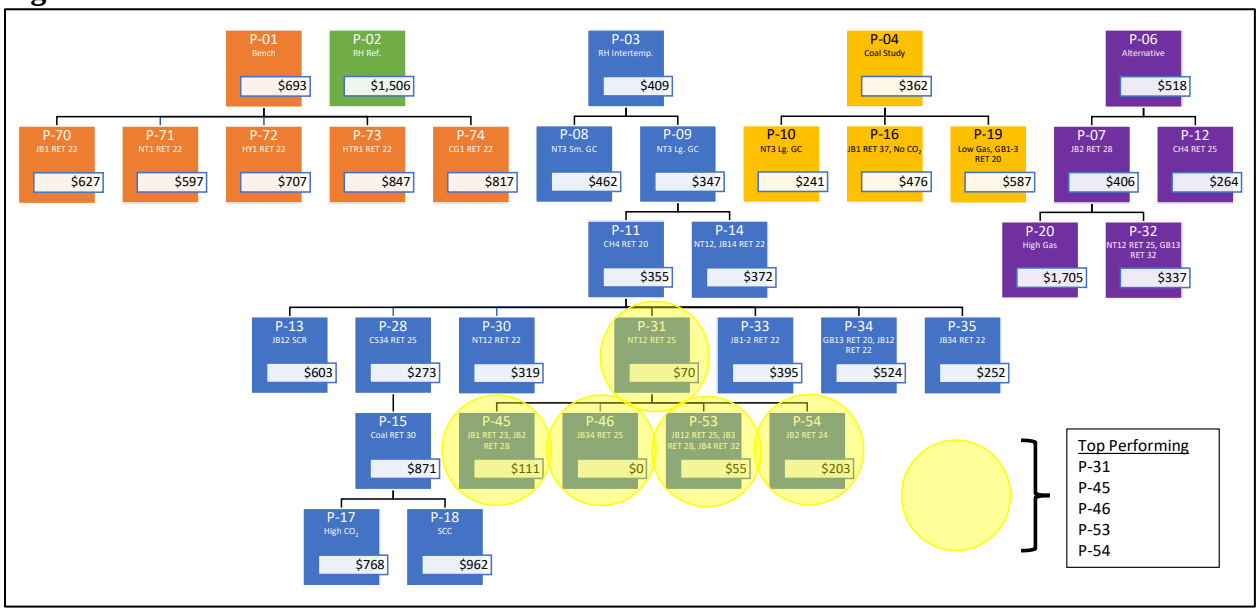
Table 8.1 – Initial Portfolio Cost and Risk Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P46	**23,413**	**0**	**1**	**24,605**	**0**	**1**	**0.012%**	**0.006%**	**26**	**560,199**	**133,090**	**6**
P53	**23,468**	**55**	**2**	**24,662**	**57**	**2**	**0.012%**	**0.006%**	**27**	**562,025**	**134,915**	**7**
P31	**23,484**	**70**	**3**	**24,678**	**72**	**3**	**0.009%**	**0.002%**	**19**	**588,421**	**161,312**	**19**
P45	**23,525**	**111**	**4**	**24,722**	**116**	**4**	**0.008%**	**0.001%**	**10**	**583,981**	**156,872**	**15**
P54	**23,616**	**203**	**5**	**24,819**	**213**	**5**	**0.009%**	**0.002%**	**17**	**584,377**	**157,267**	**16**
P10	23,655	241	6	24,864	259	6	0.009%	0.003%	21	571,707	144,597	11
P35	23,666	252	7	24,871	266	7	0.010%	0.004%	23	557,489	130,379	5
P28	23,686	273	9	24,888	283	9	0.008%	0.002%	14	594,322	167,212	20
P30	23,733	319	10	24,941	336	10	0.010%	0.003%	22	587,905	160,795	18
P11	23,768	355	13	24,976	370	13	0.008%	0.001%	9	596,911	169,801	23
P12	23,678	264	8	24,886	281	8	0.008%	0.002%	13	579,167	152,057	12
P13	24,016	603	24	25,234	629	24	0.008%	0.001%	11	604,396	177,286	25
P14	23,786	372	15	25,000	394	15	0.015%	0.009%	28	535,774	108,664	4
P32	23,750	337	11	24,959	354	11	0.008%	0.002%	15	583,565	156,455	14
P09	23,760	347	12	24,970	365	12	0.009%	0.002%	20	597,855	170,745	24
P04	23,775	362	14	24,993	387	14	0.011%	0.004%	24	567,901	140,792	8
P33	23,809	395	16	25,024	419	16	0.007%	0.001%	7	569,586	142,476	10
P07	23,819	406	17	25,033	427	18	0.007%	0.000%	5	581,583	154,474	13
P03	23,822	409	18	25,033	427	17	0.008%	0.002%	12	595,728	168,619	21
P08	23,875	462	19	25,092	486	19	0.009%	0.002%	18	595,956	168,846	22
P16	23,889	476	20	25,097	491	20	0.007%	0.000%	2	669,944	242,834	30
P06	23,932	518	21	25,151	546	21	0.007%	0.001%	6	585,907	158,798	17
P34	23,938	524	22	25,157	551	22	0.008%	0.001%	8	568,422	141,312	9
P19	24,000	587	23	25,211	606	23	0.007%	0.000%	3	607,157	180,047	27
P01	24,106	693	25	25,327	721	25	0.006%	0.000%	1	616,896	189,786	29
P17	24,182	768	26	25,400	795	26	0.057%	0.051%	29	475,390	48,281	3
P15	24,285	871	27	25,516	911	27	0.012%	0.005%	25	472,569	45,459	2
P18	24,376	962	28	25,602	997	28	0.111%	0.104%	30	427,110	0	1
P02	24,919	1,506	29	26,183	1,577	29	0.009%	0.002%	16	605,872	178,763	26
P20	25,118	1,705	30	26,385	1,780	30	0.007%	0.000%	3	607,157	180,047	27

PacifiCorp identified the first five cases in the table (in bold) as top-performing cases selected for more refined C-series analysis.

Figure 8.8 summarizes the stochastic mean PVRR relationships among the initial portfolio cases in the "family tree" format summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). Dollar figures associated with each case represent the increase in system PVRR relative to the lowest-cost case (case P-46). Note, that cases P-70 through P-74 were developed in response to stakeholder interests to reaffirm conclusions from the coal study, which indicate that potential early coal unit retirements should be focused on Naughton and Jim Bridger units.

Figure 8.8 – Relative Cost of Stochastic Mean to the Lowest-Cost Initial Case



C-Series Portfolios

In the C-series of cases, top-performing portfolios from the initial set of portfolios, and additional portfolios produced in response to stakeholder interest, receive an expanded reliability analysis. For each of these cases, PacifiCorp produced six additional deterministic hourly studies to ensure that each year is analyzed through 2030 (i.e., adding test years for 2024-2029). This improves the granularity at which reliability resources are applied and provides for a better comparison of cost and risk metrics between these cases.

As described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), in addition to expanding the reliability assessment step of portfolio development the C-series also removes proxy stand-alone solar resources from the resource options available to the SO model. This allows the SO model to efficiently combine renewables and storage resources in order to accrue combined economic benefits that would otherwise be lost.

As noted above, in addition to the five top performing cases derived from the initial portfolios, the C-series includes five additional cases developed after stakeholder discussion at the September 5-6, 2019 public-input meeting. Table 8.2 summarizes the five additional C-series cases.

Table 8.2 – Additional C-Series Cases

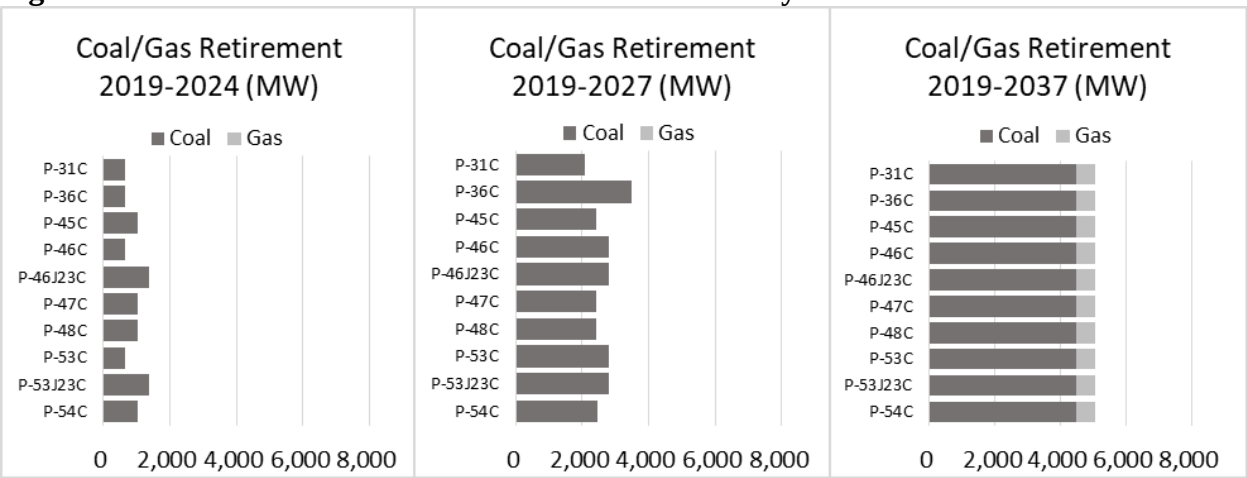
Case	Description
P-36C	A variant of Case P-14 with Jim Bridger 1-2 and Naughton 1-2 retired at the end of 2025.
P-46J23C	A variant of Case P-46 with Jim Bridger 3-4 retired at the end of 2023.
P-47C	A variant of Case P-45 with Jim Bridger 3-4 retired at the end of 2035.
P-48C	A variant of Case P-45 with Jim Bridger 3-4 retired at the end of 2033.
P-53J23C	A variant of Case P-53 with Jim Bridger 1-2 retired at the end of 2023.

C-Series Portfolio Development

Coal and Gas Resource Retirements

Figure 8.9 summarizes cumulative nameplate coal and gas retirements for each C-series case over the near-term, mid-term, and long-term. Note, in reporting cumulative capacity in this figure and the similar figures that follow, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix M (Case Study Fact Sheets). Through 2027, total coal retirements range between 2,091 MW (case P-31C) and 3,499 MW (case P-36C). Through the end of 2037, total coal retirements approach 4,500 MW in each case.

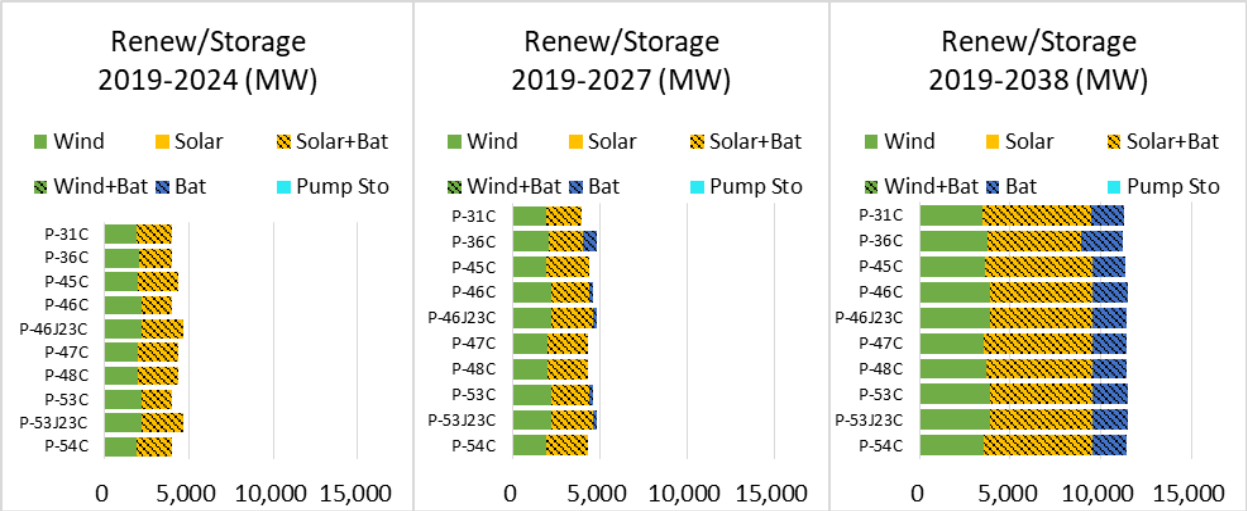
Figure 8.9 – C-Series Coal and Gas Retirements Summary



New Renewable and Storage Resources

Figure 8.10 summarizes the nameplate capacity of new renewables and storage resource additions for each C-series case. In all cases the SO model selects Energy Gateway South in 2024 (a proxy for year-end 2023) along with 1,920 MW of new wind in eastern Wyoming. Through 2027, new renewable capacity ranges between 3,992 MW (case P-31C) and 4,645 MW (cases P-46J23C and P-53J23C). By the end of 2038, new renewable capacity ranges between 8,905 MW (case P-36C) and 9,574 MW (cases P-46C, P-47C, P-48C, P-53C, P-53J23C and P-54C). New battery capacity ranges between 518 MW and 729 MW through 2027 and over 3,300 MW by the end of 2038.

Figure 8.10 – C-series New Renewable and Storage Resources Summary

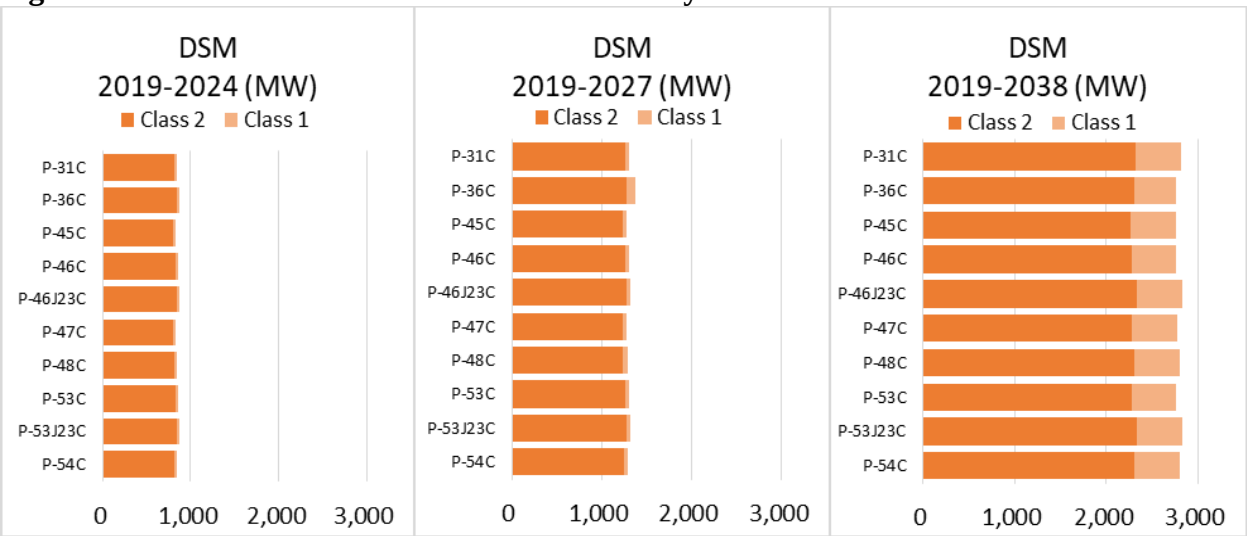


Note: For wind or renewable resources paired with battery, the capacity for the renewable resource is shown in the graph. The battery capacity paired with these resources is 25 percent of the renewable resource capacity.

Incremental Demand-Side Management (DSM)

Figure 8.11 summarizes aggregated DSM selections by case. Selected volumes of DSM are relatively stable among all C-series cases. On average, Class 2 DSM capacity totals 826 MW through 2024, 1,257 MW through 2027, and 2,299 MW through 2038. On average, Class 1 DSM capacity totals 29 MW through 2022, 45 MW through 2027, and 485 MW through 2038.

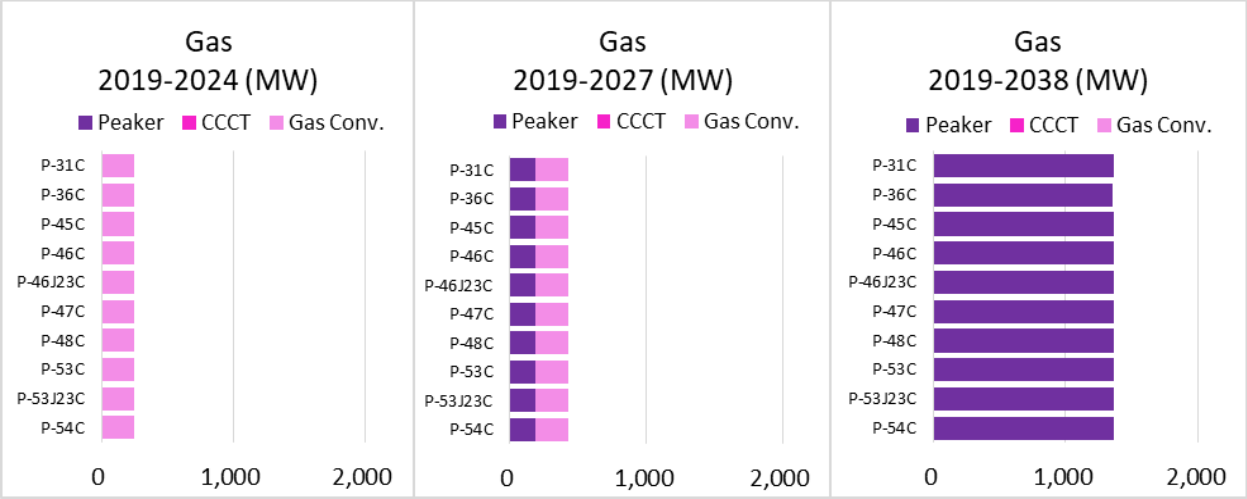
Figure 8.11 – C-Series Incremental DSM Summary



New Natural Gas Resources

Figure 8.12 summarizes cumulative natural gas expansion resources for each C-series portfolio. In cases where Naughton 3 converts to natural gas, it is assumed to retire at the end of 2029, so it does not show up in the results through 2038. Each case includes the large gas conversion of Naughton Unit 3 in 2020, and includes 185 MW of new peaking gas capacity in 2026. Case P-36C includes 1,356 MW of new peaking gas through the end of 2038; all other C-series cases include 1,367 MW of new gas peaking gas capacity through the end of 2038. None of these cases include new gas CCCT capacity.

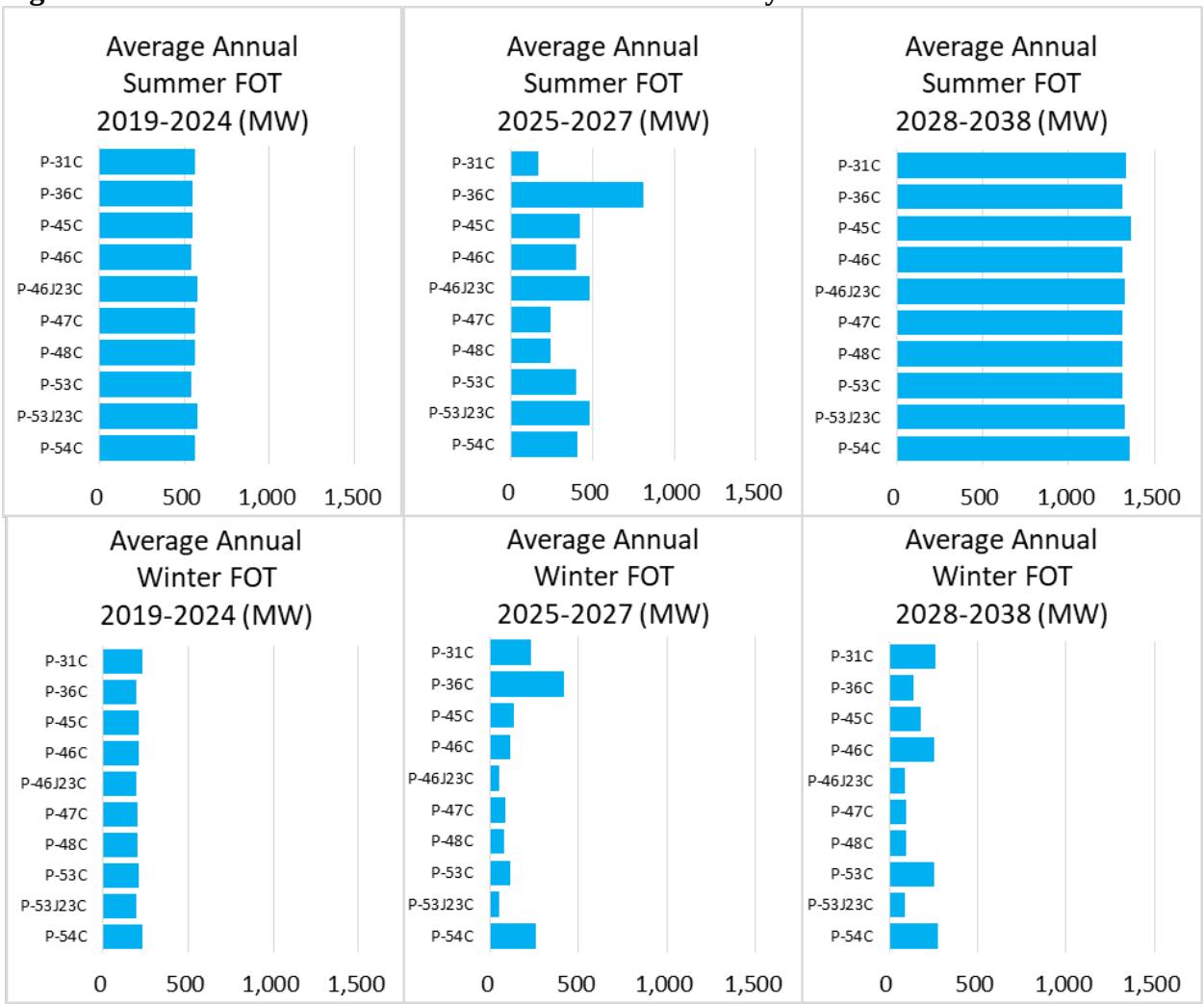
Figure 8.12 – C-Series New Natural Gas Resource



Front Office Transactions

Figure 8.13 summarizes the average of FOTs for each C-Series portfolio during the summer and winter peak periods. The summer and winter FOT limit assumed for the 2019 IRP is 1,425 MW. Market reliance is reduced in the 2025 to 2027 timeframe, coinciding with the addition of new transmission, new wind, and new solar+battery resources—on average, summer FOT purchases are 406 MW per year over this period. Longer-term, summer FOTs increase similarly among these cases, on average ranging between 1,310 MW and 1,361 MW each year from 2028-2038. Winter FOTs remain well below the volumes included in each portfolio to cover the summer peak period.

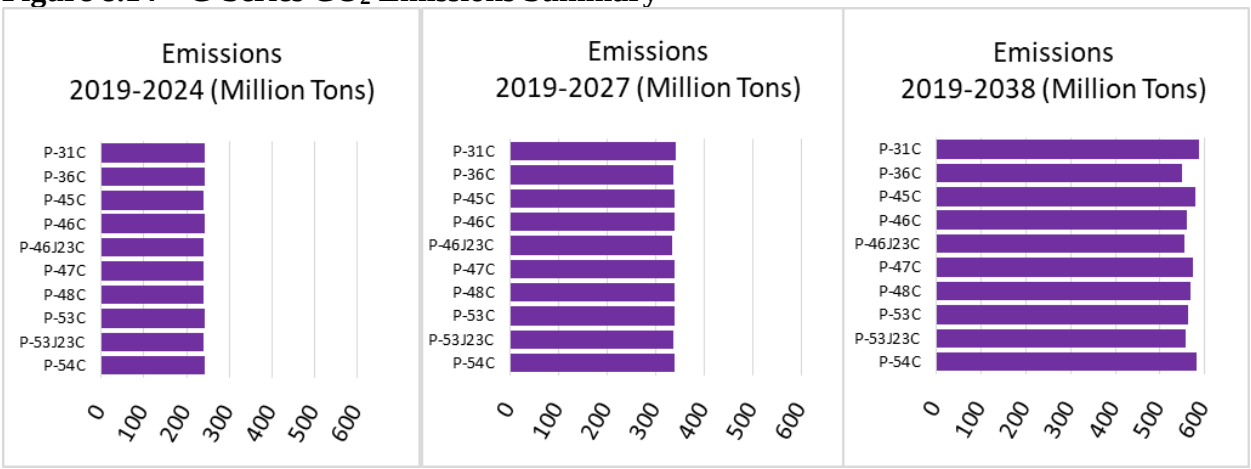
Figure 8.13 – C-Series Front Office Transactions Summary



CO_2 Emissions

Figure 8.14 reports cumulative CO_2 emissions for each C-series portfolio. Total CO_2 emissions is similar among these cases through 2027. Through 2038, total CO_2 emissions range between 550 million tons (case P-36C) and 588 million tons (case P-31C).

Figure 8.14 – C-Series CO_2 Emissions Summary



C Series Case Cost and Risk Summary

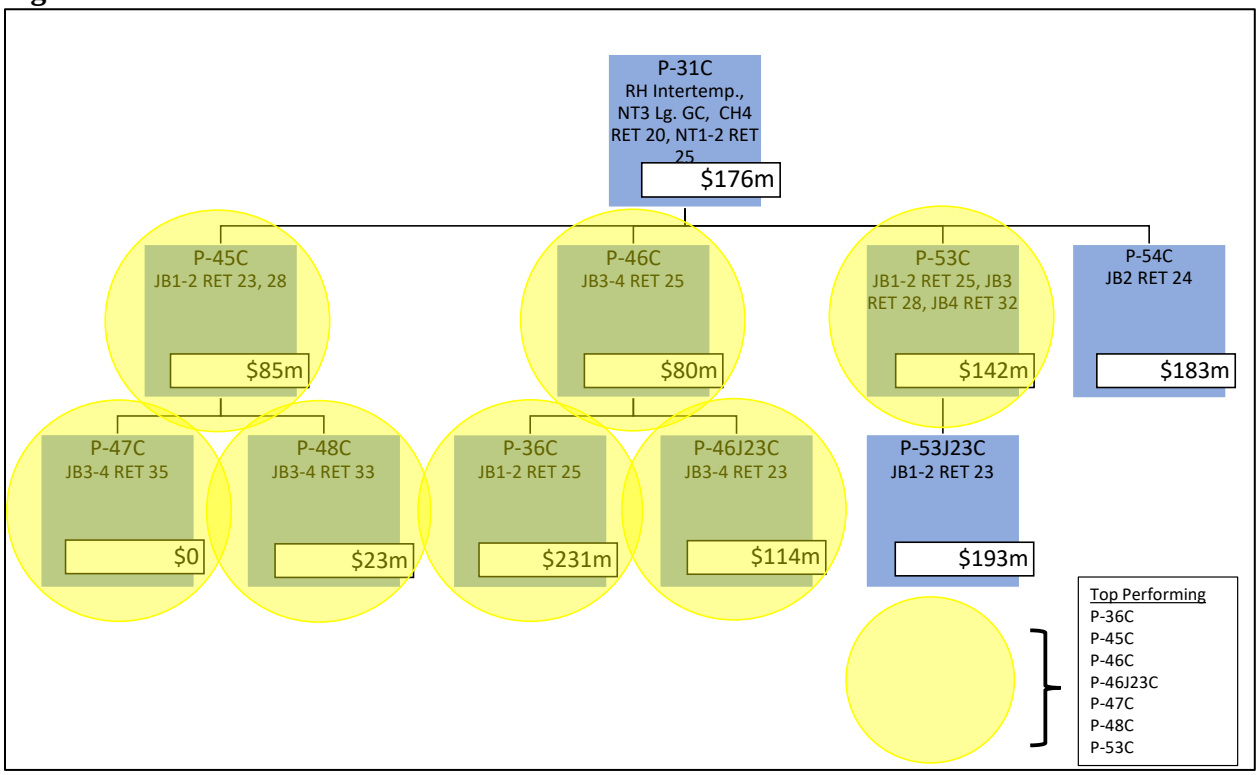
Table 8.3 – C Series Case Cost and Risk Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P47C	**23,198**	**$0**	**1**	**24,367**	**$0**	**1**	**0.012%**	**0.002%**	**7**	**573,088**	**22,855**	**7**
P48C	**23,221**	**$23**	**2**	**24,391**	**$24**	**2**	**0.011%**	**0.001%**	**5**	**567,025**	**16,792**	**6**
P46C	**23,278**	**$80**	**3**	**24,462**	**$95**	**3**	**0.011%**	**0.001%**	**3**	**560,210**	**9,977**	**4**
P45C	**23,283**	**$85**	**4**	**24,468**	**$101**	**4**	**0.010%**	**0.000%**	**1**	**578,607**	**28,374**	**8**
P46J23C	**23,312**	**$114**	**5**	**24,488**	**$121**	**5**	**0.013%**	**0.002%**	**9**	**553,673**	**3,440**	**2**
P53C	**23,340**	**$142**	**6**	**24,528**	**$161**	**6**	**0.011%**	**0.001%**	**4**	**562,972**	**12,739**	**5**
P31C	23,374	$176	7	24,562	$195	8	0.010%	0.000%	2	588,334	38,101	10
P54C	23,381	$183	8	24,558	$191	7	0.012%	0.002%	6	581,465	31,232	9
P53J23C	23,391	$193	9	24,570	$203	9	0.012%	0.002%	8	556,990	6,757	3
P36C	**23,430**	**$231**	**10**	**24,614**	**$247**	**10**	**0.013%**	**0.003%**	**10**	**550,233**	**0**	**1**

PacifiCorp identified the cases in bold in Table 8.3 as top-performing cases selected for more refined analysis in the next step of the portfolio-development process (cases P-36C, P-46JC23C, P-47C, P-48C, P-46C, P-45C, and P53C). While cases P36C does not perform well on cost metrics relative to the other cases, in response to stakeholder interests, PacifiCorp included this case the list of top-performing C-series cases given its high ranking in total CO_2 emissions.

Figure 8.15 summarizes the stochastic mean PVRR relationships among the C-series cases in the "family tree" format summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). Dollar figures associated with each case represent the increase in system PVRR relative to the lowest-cost case (case P-47C).

Figure 8.15 – Relative Cost of Stochastic Mean to the Lowest-Cost C Series Case



CP-Series Portfolios

In the CP-series of cases, top-performing portfolios from the C-series of cases are further refined. The CP-series includes the additional solar+battery analysis, and to ensure that there is no potential for an inconsistent application of annual reliability requirements beyond 2030, adds seven additional years (i.e., 2031-2037) of hourly deterministic analysis to the reliability assessment. This addition yields a total of 16 deterministic studies covering the period 2023-2038.

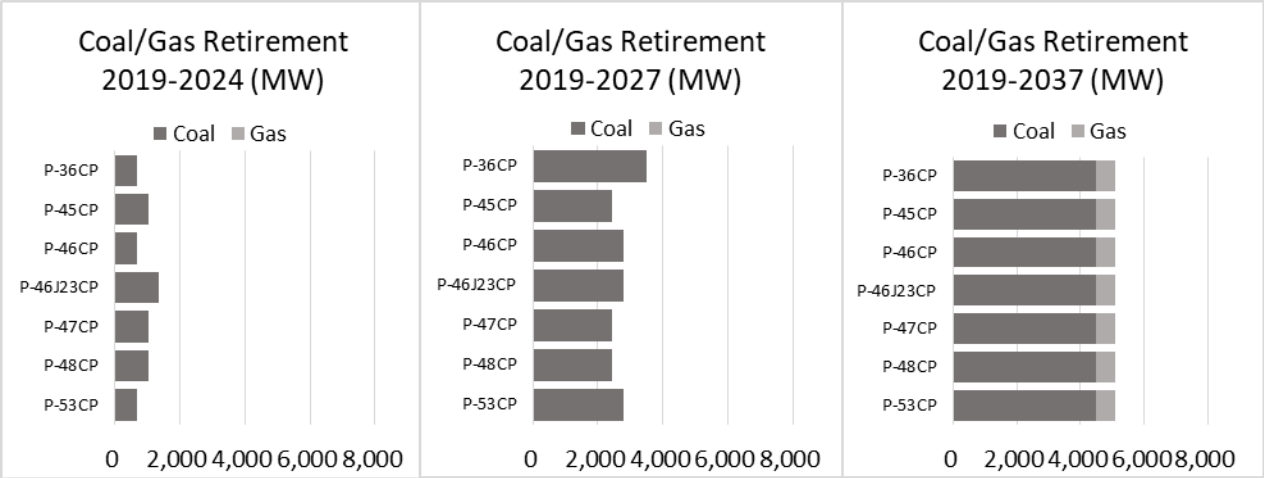
This refinement further improves the granularity at which reliability resources are applied and therefore provides an improved comparison of cost and risk metrics between the top-performing cases. The resulting portfolios were also evaluated among a range of price-policy scenarios.

CP-Series Portfolio Development

Coal and Gas Resource Retirements

Figure 8.16 summarizes cumulative nameplate coal and gas retirements for each CP-series case over the near-term, mid-term, and long-term. Note, in reporting cumulative capacity in this figure and the similar figures that follow, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix M (Case Study Fact Sheets). Through 2027, total coal retirements range between 2,441 MW (case P-45CP, P-47CP, P-48CP) and 3,499 MW (case P-36CP). Through the end of 2037, total coal retirements approach 4,500 MW in each case.

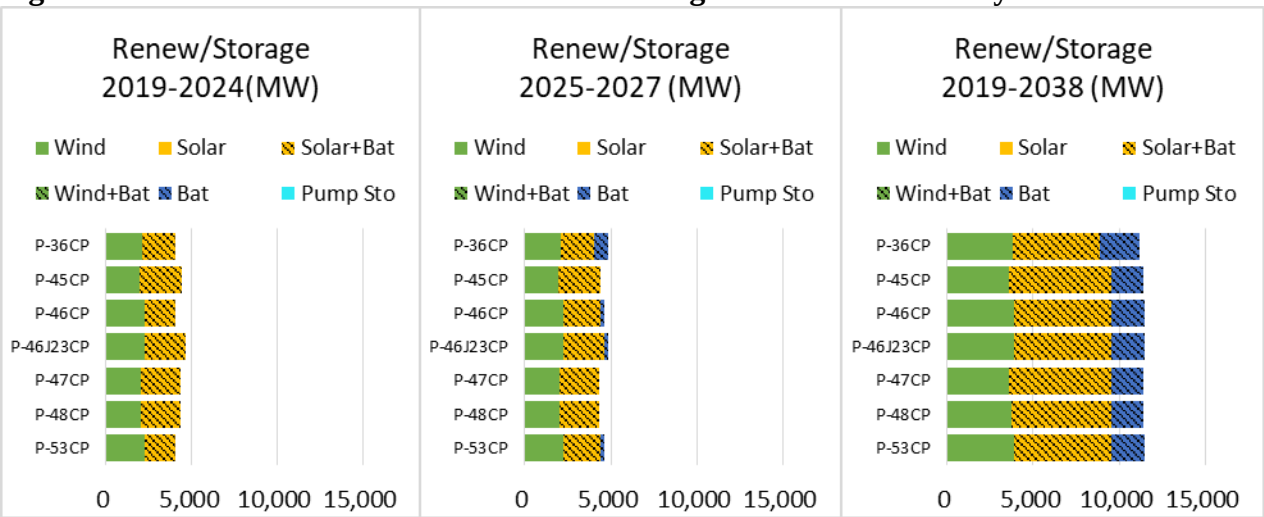
Figure 8.16 – CP-Series Coal and Gas Retirements Summary



New Renewable and Storage Resources

Figure 8.17 summarizes the nameplate capacity of new renewables and storage resource additions for each CP-series case. In all cases the SO model selects Energy Gateway South in 2024 (a proxy for year-end 2023) along with 1,920 MW of new wind in eastern Wyoming. Through 2027, new renewable capacity ranges between 3,339 MW (case P-47CP) and 4,409 MW (cases P-46CP and P-53CP). By the end of 2038, new renewable capacity ranges between 9,512 MW (case P-45CP) and 9,574 MW in the other four cases. New battery capacity ranges between 587 MW and 729 MW through 2027 and over 3,300 MW by the end of 2038.

Figure 8.17 – CP-Series New Renewable and Storage Resources Summary

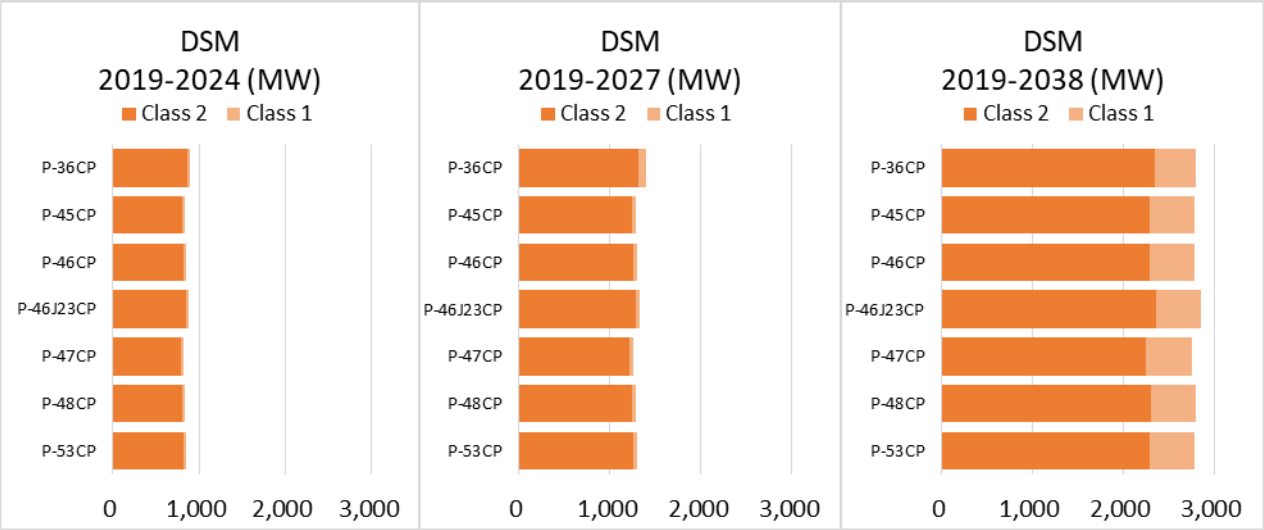


Note: For wind or renewable resources paired with battery, the capacity for the renewable resource is shown in the graph. The battery capacity paired with these resources is 25 percent of the renewable resource capacity.

Incremental Demand-Side Management (DSM)

Figure 8.18 summarizes aggregated DSM selections by case. Selected volumes of DSM are relatively stable among all CP-series cases. On average, Class 2 DSM capacity totals 826 MW through 2024, 1,259 MW through 2027, and 2,306 MW through 2038. On average, Class 1 DSM capacity totals 29 MW through 2024, 45 MW through 2027, and 487 MW through 2038.

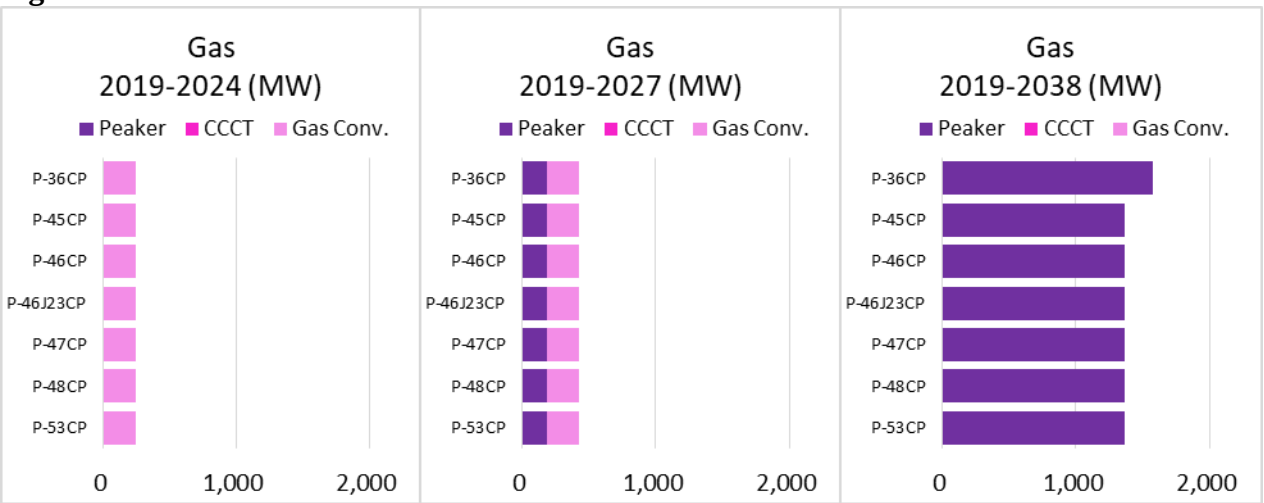
Figure 8.18 – CP-Series Incremental DSM Summary



New Natural Gas Resources

Figure 8.19 summarizes cumulative natural gas expansion resources for each CP series portfolio. In cases where Naughton Unit 3 converts to natural gas, it is assumed to retire at the end of 2029, so it does not show up in the results through 2038. Each case includes 185 MW of new peaking gas capacity in 2026. All CP-series cases except case P-36C include 1,367 MW of new gas peaking gas capacity through the end of 2038. Case P-36CP, includes 210 MW of gas peaking capacity over and above the other CP-series cases, added in 2028. None of the cases include new gas CCCT capacity.

Figure 8.19 – CP-Series New Natural Gas Resource

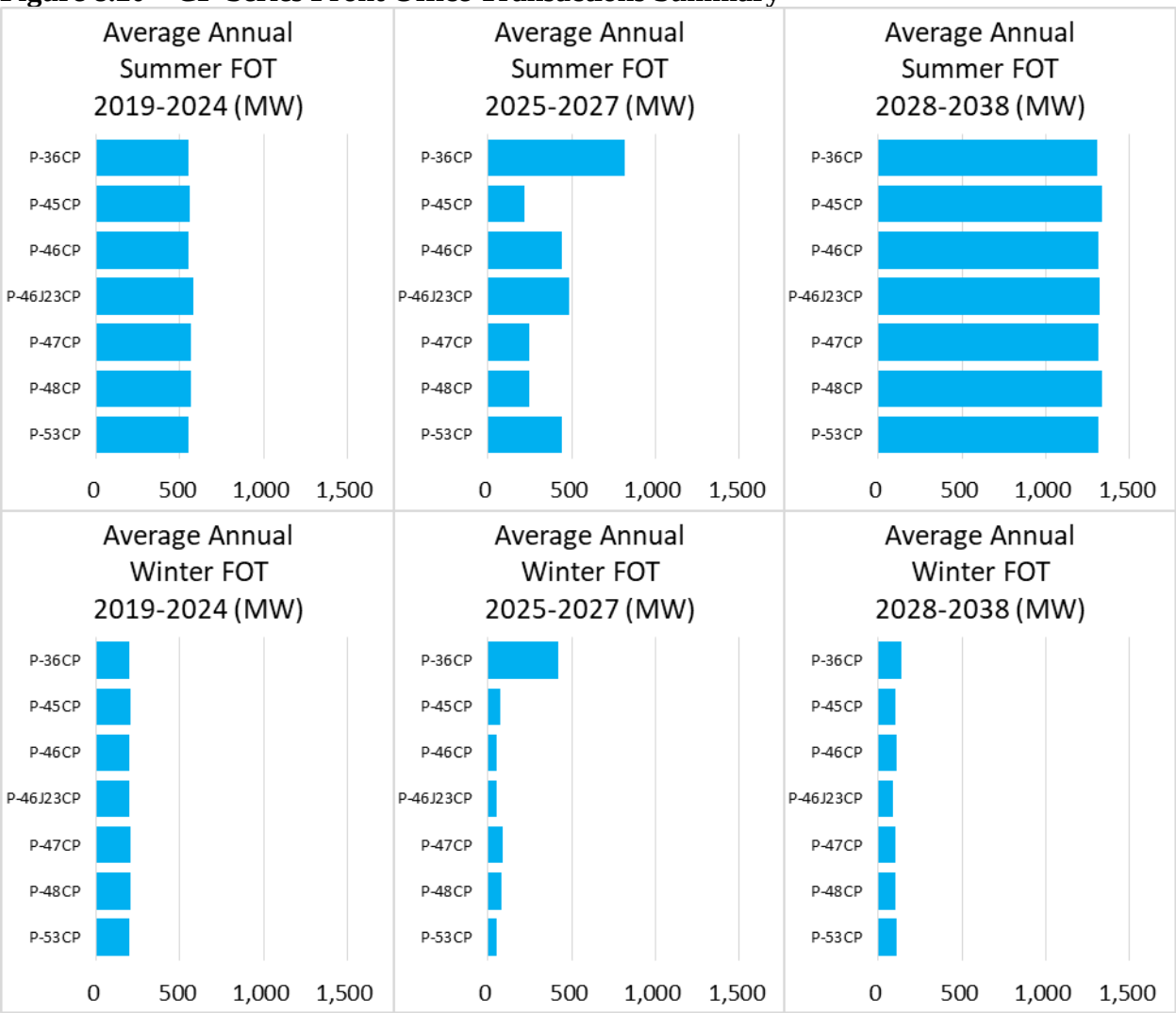


Front Office Transactions

Figure 8.20 summarizes summer and winter FOTs for each CP-series case. The summer and winter FOT limit assumed for the 2019 IRP is 1,425 MW. Market reliance is reduced in the 2025 to 2027 timeframe, coinciding with the addition of new transmission, new wind, and new solar+battery resources—on average, summer FOT purchases are 411 MW per year over this period. Removing P-36CP (an outlier with nearly double the FOTs of other CP-series cases) from the mix yields an average of 344 MW per year. Longer-term, summer FOTs increase similarly among these cases,

on average ranging between 1,310 MW and 1,334 MW each year from 2028-2038. Winter FOTs remain well below the volumes included in each portfolio to cover the summer peak period.

Figure 8.20 – CP-Series Front Office Transactions Summary



CO_2 Emissions

Figure 8.21 reports cumulative CO_2 emissions for each CP-series portfolio. Total CO_2 emissions is similar among these cases through 2027. Through 2038, total CO_2 emissions range between 558 million tons (case P-46CP) and 577 million tons (case P-45CP).

Figure 8.21 – CP-Series CO2 Emissions Summary

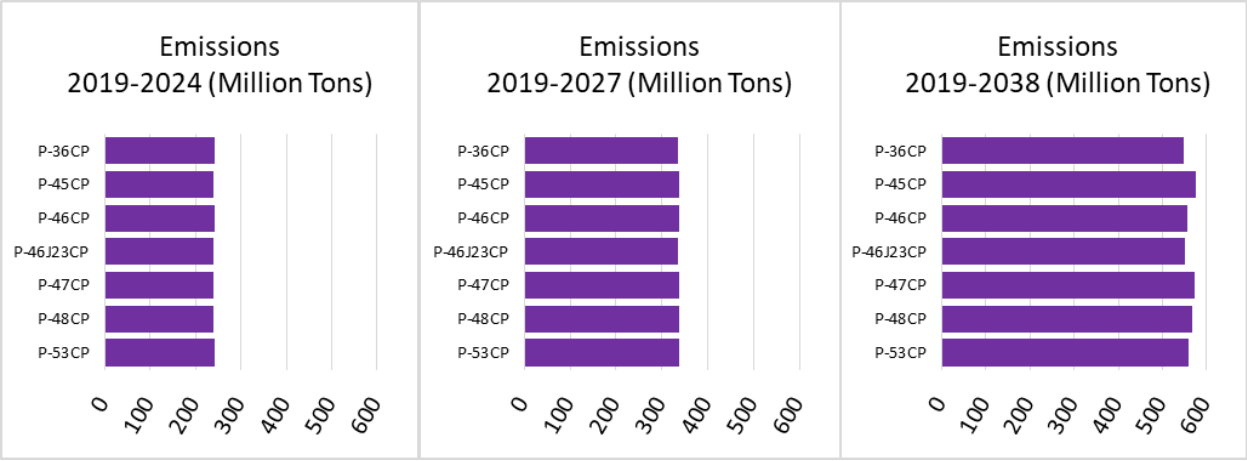
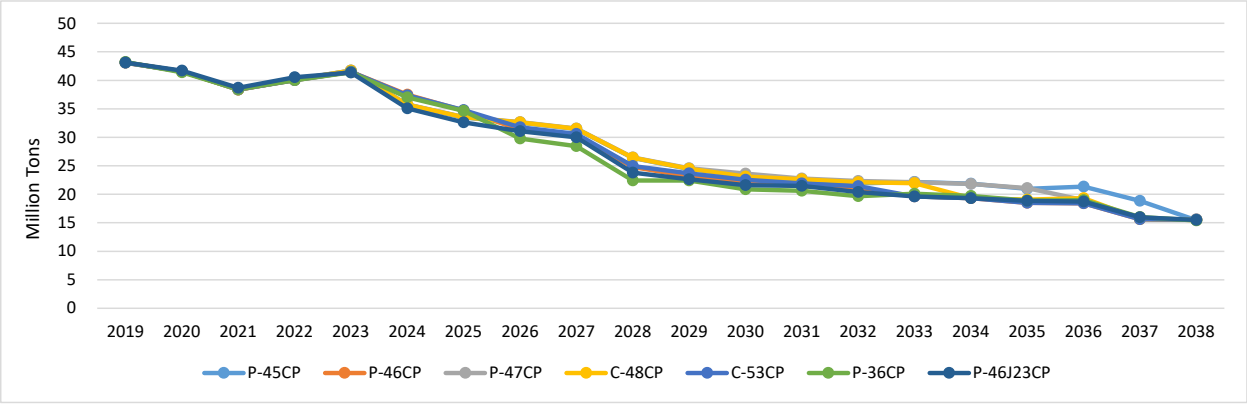


Figure 8.22 shows the annual emissions profile for each of the seven CP-series cases through the end of the planning period in 2038.

Figure 8.22 – Annul CO_2 Emissions among CP-Series Cases



CP-Series Cost and Risk Summary

The following tables and figures report the results of the CP-series cases for four price-policy scenarios. Each scenario assumes a low, medium or high gas price future, combined with either a zero, medium or high CO_2 price future. In addition to the seven CP-series cases, results from the five initial portfolios that were developed under varying natural gas price and CO_2 price assumptions are presented (cases P-16 through P-20).

CP-Series Medium Gas/Medium CO_2 Scenario

In the medium gas/medium CO_2 price-policy scenario, Case P-45CP outperforms other cases on stochastic mean costs, risk-adjusted costs, and energy not served (ENS). While case P-45CP has higher cumulative CO_2 emissions, the case with the lowest cumulative emissions (case P-36CP) has a risk-adjusted cost that is $235m higher than case P-45CP. Further, as shown in the figure above, the annual emissions profile among the CP-series of cases is similar. None of the price-policy cases outperform case P-45CP on cost metrics.

Table 8.4 – CP-Series, Medium Gas/Medium CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CP	**23,192**	**$0**	**1**	**24,360**	**$0**	**1**	**0.010%**	**0.000%**	**1**	**577,439**	**28,013**	**7**
P48CP	23,205	$13	2	24,374	$13	2	0.013%	0.003%	2	567,889	18,463	5
P47CP	23,219	$27	3	24,388	$28	3	0.013%	0.004%	7	573,649	24,222	6
P46CP	23,292	$100	4	24,465	$105	4	0.013%	0.003%	6	557,824	8,397	3
P46J23CP	23,303	$112	5	24,478	$118	5	0.013%	0.003%	2	552,065	2,639	2
P53CP	23,348	$156	6	24,524	$164	6	0.013%	0.003%	5	560,553	11,127	4
P36CP	23,413	$221	7	24,595	$235	7	0.013%	0.003%	2	549,427	0	1

Table 8.5 – Price-Policy Cases, Medium Gas/Medium CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P16	23,889	$0	1	25,097	$0	1	0.007%	0.000%	1	669,944	242,834	5
P19	24,000	$111	2	25,211	$115	2	0.007%	0.000%	2	607,157	180,047	3
P17	24,182	$292	3	25,400	$303	3	0.057%	0.051%	4	475,390	48,281	2
P18	24,376	$487	4	25,602	$506	4	0.111%	0.104%	5	427,110	0	1
P20	25,118	$1,229	5	26,385	$1,289	5	0.007%	0.000%	2	607,157	180,047	3

CP-Series Low Gas/No CO_2 Scenario

In the low gas/zero CO_2 scenario, Case P-45CP outperforms other cases on stochastic mean costs, risk-adjusted costs, and ENS. While P-45CP has higher cumulative CO_2 emissions, the case with the lowest cumulative emissions (case P-46J23CP) has a risk-adjusted cost that is $222m higher than case P-45CP. Further, as shown in the figure above, the annual emissions profile among the CP-series of cases is similar. Cases P-16 and P-19, which were developed without a CO_2 price assumption and with low gas price assumptions, respectively, are among the top-performing price-policy cases when analyzed in a low gas/zero CO_2 price-policy scenario.

Table 8.6 – CP-Series, Low Gas/Zero CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CP	**20,094**	**$0**	**1**	**21,105**	**$0**	**1**	**0.010%**	**0.000%**	**1**	**577,806**	**28,502**	**7**
P47CP	20,130	$36	2	21,143	$38	2	0.013%	0.004%	7	572,966	23,661	5
P48CP	20,173	$79	3	21,187	$83	3	0.013%	0.003%	3	567,163	17,859	4
P46CP	20,285	$191	4	21,305	$201	4	0.013%	0.003%	6	555,322	6,018	2
P46J23CP	20,306	$212	5	21,327	$222	5	0.013%	0.003%	3	549,304	0	1
P53CP	20,327	$233	6	21,349	$245	6	0.013%	0.003%	5	558,186	8,882	3
P36CP	23,192	$3,098	7	24,360	$3,256	7	0.010%	0.000%	1	577,439	28,135	6

Table 8.7 – Price-Policy Cases, Low Gas/No CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P16	19,448	$0	1	20,427	$0	1	0.007%	0.000%	1	674,184	255,509	5
P19	20,194	$746	2	21,209	$782	2	0.007%	0.000%	2	607,941	189,266	4
P20	20,833	$1,386	3	21,881	$1,453	3	0.007%	0.000%	3	579,150	160,476	3
P17	21,013	$1,565	4	22,071	$1,643	4	0.057%	0.051%	4	465,998	47,324	2
P18	22,456	$3,008	5	23,587	$3,160	5	0.111%	0.105%	5	418,674	0	1

CP-Series High Gas/High CO_2 Scenario

In the high gas/high CO_2 scenario, Case P-48CP outperforms other cases on stochastic mean costs and risk-adjusted costs. Case P-45CP ranks second in stochastic mean and risk-adjusted cost and first in ENS. While P-45CP has higher cumulative CO_2 emissions, the case with the lowest cumulative emissions (case P-36CP) has a risk-adjusted cost that is $155m higher than case P-45CP. Further, as shown in the figure above, the annual emissions profile among the CP-series of cases is similar. Cases P-18, P-20, and P-17, which were developed using a social cost of carbon CO_2 price assumption, a high gas price assumption, and a high CO_2 price assumption, respectively, are among the top-performing price-policy cases when analyzed in a high gas/high CO_2 price-policy scenario.

Table 8.8 – CP-Series, High Gas/High CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P48CP	27,736	$0	1	29,135	$0	1	0.013%	0.003%	2	562,313	18,221	5
P45CP	**27,786**	**$51**	**2**	**29,188**	**$53**	**2**	**0.010%**	**0.000%**	**1**	**571,643**	**27,550**	**7**
P47CP	27,805	$69	3	29,208	$72	3	0.013%	0.004%	7	568,183	24,090	6
P46J23CP	27,812	$76	4	29,215	$79	4	0.013%	0.003%	2	549,152	5,059	2
P46CP	27,814	$78	5	29,217	$82	5	0.013%	0.003%	6	553,331	9,239	3
P36CP	27,881	$145	6	29,290	$155	6	0.013%	0.003%	2	544,092	0	1
P53CP	27,889	$153	7	29,296	$161	7	0.013%	0.003%	5	556,201	12,108	4

Table 8.9 – Price-Policy Cases, High Gas/High CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P18	27,785	$0	1	29,187	$0	1	0.112%	0.105%	5	431,628	0	1
P20	28,397	$612	2	29,832	$646	2	0.007%	0.000%	3	572,793	141,165	3
P17	28,858	$1,073	3	30,312	$1,125	3	0.057%	0.051%	4	478,795	47,167	2
P19	29,224	$1,439	4	30,701	$1,514	4	0.007%	0.000%	2	598,587	166,960	4
P16	29,847	$2,062	5	31,357	$2,170	5	0.007%	0.000%	1	653,963	222,335	5

CP-Series Social Cost of Carbon Scenario

In the social cost of carbon scenario, case P-46J23CP outperforms other cases on stochastic mean costs and risk-adjusted costs. While case P-45CP ranks sixth in these metrics and first in ENS, case P-46J23CP has a risk-adjusted PVRR cost that is $118m higher cost than P-45CP when the medium gas/medium CO_2 price-policy assumptions is applied. The highest ranking portfolio with regard to cumulative CO_2 emissions is case P-36CP. Case P-18, which was developed using a social cost of carbon CO_2 price assumption, is among the top-performing price-policy cases when analyzed in a social cost of carbon price-policy scenario. Case P-18 has a risk-adjusted PVRR that is over $1.2b higher cost than case P-45CP when medium gas/medium CO_2 price-policy assumptions are applied.

As was discussed with stakeholders at the October 3-4, 2019 public-input meeting, PacifiCorp applied social cost of carbon CO_2 prices to this price-policy scenario analysis such that the price for the social cost of carbon is reflected in market prices and dispatch costs. Consequently, it assumes that system operations (plant dispatch and market transactions) are not aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of carbon and PacifiCorp does not directly incur emissions costs at the price assumed for the social cost of carbon). Consequently, and unlike the other price-policy scenarios reviewed above, the model results for the social cost of carbon price-policy scenario represent cost drivers that are materially divergent from the cost drivers in the market. This creates challenges in understanding how to interpret the results from this price-policy scenario.

Table 8.10 – CP-Series Social Cost of Carbon Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P46J23CP	36,555	$0	1	38,394	$0	1	0.013%	0.003%	3	411,129	5,160	2
P36CP	36,561	$6	2	38,405	$11	2	0.010%	0.000%	1	405,969	0	1
P46CP	36,703	$149	3	38,550	$155	3	0.013%	0.003%	6	414,320	8,351	3
P48CP	36,798	$243	4	38,649	$254	4	0.013%	0.003%	3	424,073	18,104	5
P53CP	36,829	$274	5	38,681	$287	5	0.013%	0.003%	5	418,116	12,147	4
P45CP	**36,934**	**$379**	**6**	**38,791**	**$397**	**6**	**0.010%**	**0.000%**	**1**	**432,168**	**26,199**	**7**
P47CP	36,936	$381	7	38,794	$399	7	0.013%	0.004%	7	429,251	23,282	6

Table 8.11 – Price-Policy Case Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P18	35,276	$0	1	37,051	$0	1	0.112%	0.105%	5	321,000	0	1
P17	36,415	$1,139	2	38,247	$1,197	2	0.057%	0.051%	4	366,220	45,221	2
P20	37,527	$2,251	3	39,421	$2,370	3	0.007%	0.000%	3	437,132	116,133	3
P19	38,396	$3,120	4	40,334	$3,283	4	0.007%	0.000%	2	459,469	138,469	4
P16	39,712	$4,436	5	41,717	$4,666	5	0.007%	0.000%	1	496,702	175,703	5

Based upon the results summarized above, PacifiCorp identified case P-45CP as the top-performing case in the CP-series of cases. Relative cost differences between case P-45CP and the cases with the lowest cumulative CO_2 emissions (cases P-36CP and P-46J23CP) do not support consideration of these two cases for potential selection as the preferred portfolio.

Front Office Transaction Portfolios

Five of the CP-series cases (all but cases P-36CP and P-46J23CP) were further analyzed for FOT risk. The FOT studies are designed to quantify the impact and risk of market reliance. As detailed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), these cases use an escalating scalar to elevate market prices during the peak months of July, August and December of every study year. This has the effect of increasing costs for market purchases or for acquisition of the alternative resources required to avoid the high market prices.

Higher FOT costs from market risk increased the PVRR by similar amounts among the cases, $820 million (3.6 percent), on average. Case P-45CP has a risk-adjusted PVRR that is $25m higher than Case P-47CP, which has the lowest PVRR when higher FOT costs are applied.

These results suggest that the risk of higher FOT costs is not materially different between cases P-45CP and P-47CP and these results do not justify driving the selection of any over the other CP-series of cases as beneficial to case P-45CP.

Table 8.12 reports FOT case evaluation results. Table 8.13 quantifies the increased system cost of escalated FOT pricing compared to the system cost of each portfolio under the medium gas, medium CO_2 price-policy scenario.

Table 8.12 – FOT Case Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P47CP	24,001	$0	1	25,209	$0	1	0.010%	0.000%	2	535,827	13,317	4
P45CP	24,024	$23	2	25,233	$25	2	0.009%	0.000%	1	540,134	17,623	5
P48CP	24,098	$97	3	25,312	$104	3	0.012%	0.002%	3	533,930	11,419	3
P46CP	24,099	$98	4	25,314	$105	4	0.013%	0.004%	5	522,510	0	1
P53CP	24,164	$163	5	25,382	$173	5	0.013%	0.003%	4	525,364	2,854	2

Table 8.13 – FOT Case System Cost Impact Summary

	Stochastic Mean		
Case	PVRR ($m)	Change from CP Portfolio ($m)	Rank
P47CP	24,001	$782	1
P45CP	24,024	$832	4
P48CP	24,098	$892	5
P46CP	24,099	$807	2
P53CP	24,164	$815	3

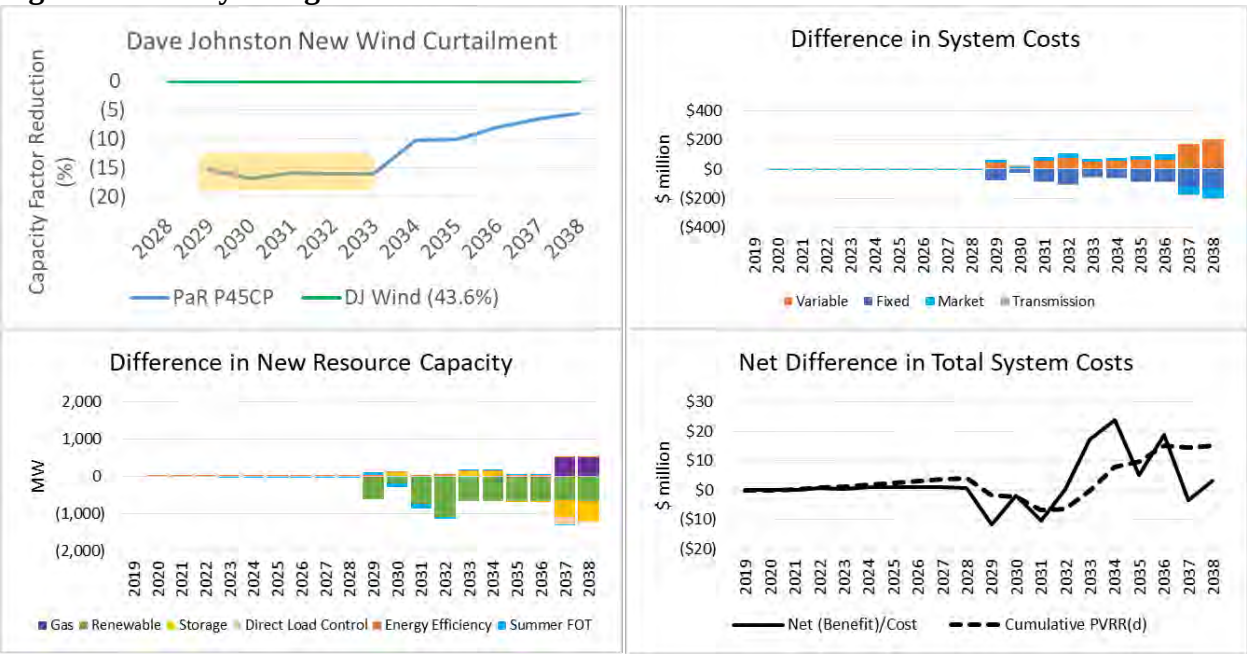
2028-2029 Wyoming Wind Case

As detailed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), PacifiCorp identified that 620 MW of Wyoming wind resources added to each portfolio in the 2028-2029 timeframe, which coincides with the assumed retirement of Dave Johnston, were being curtailed at relatively significant levels—through 2038, capacity factors average 32 percent, down from the 43.6 percent assumed without curtailment. From 2029 through 2033 the level of curtailment is higher, with output falling below a 30 percent capacity factor.

Upon observing this modeled outcome, PacifiCorp produced an new portfolio as a variant of the least cost CP series case (P-45CP) that eliminated the 620 MW of incremental Wyoming wind coming online after the retirement of Dave Johnston. This case is referred to as P-45CNW.

While the stochastic mean PVRR of P-45CNW is $15m higher than case P-45CP, as illustrated in Figure 8.23, PacifiCorp advanced Case P-45CNW as the baseline for evaluating additional "No New Natural Gas" and Energy Gateway transmission cases on the basis that it is not reasonable to include heavily curtailed wind resources in the leading case for the preferred portfolio. Further, the shifts in system costs contributing to the $15m increase in system PVRR are all beyond the action plan window, which will allow PacifiCorp to continue to evaluate potential incremental wind additions in eastern Wyoming when Dave Johnston retires in future IRPs.

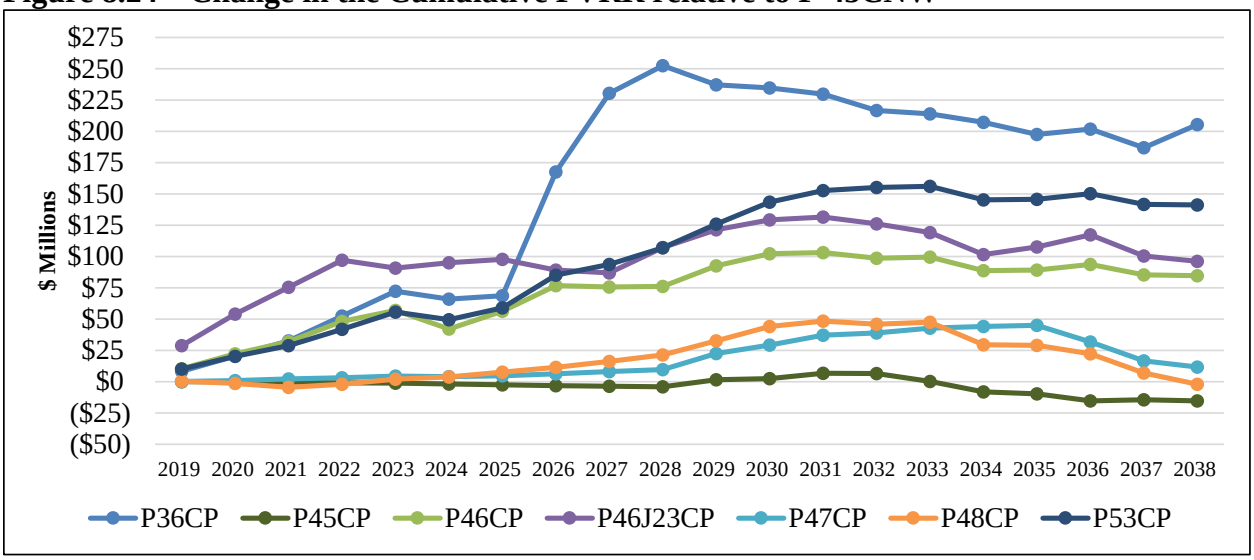
Figure 8.23 – Wyoming Wind Alternative Portfolio and Cost Evaluation



Customer Rate Pressure

Figure 8.24 shows the difference in the cumulative PVRR, as an indicator of rate pressure over time, between among the CP-series of cases discussed earlier relative to case P-45CNW when applying medium gas, medium CO_2 price-policy assumptions. Cases P-36CP, P-46CP, P-46J23CP, and P-53CP consistently trend higher than case P-45CNW. Through 2024, cases P-45CP, P-47CP, and P-48CP track relatively close to case P45-CNW. After 2024, cases P-47CP and P-48CP trend higher then case P-45CNW, and then start to converge with case P-45CNW over the longer-term.

Figure 8.24 – Change in the Cumulative PVRR relative to P-45CNW



Portfolio Development Conclusions

Based on the findings of the initial portfolios, C-series of cases, CP-series of cases, the FOT cases used to analyze market-reliance risk, and the case that eliminates highly curtailed Wyoming wind in the 2028-2029 timeframe, PacifiCorp identified case P-45CNW as the top-performing case at the conclusion of the portfolio-development process. As described below, case P-45CNW serves as the basis for additional analysis to inform final selection of the preferred portfolio.

Preferred Portfolio Selection

"No New Natural Gas" Portfolios

The "No New Natural Gas" cases, defined in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), provide two views of impacts stemming from an assumption that no new gas resources are acquired through the end of the study period. The first case, P-29 does not allow the model to select new natural gas resources (excluding the Naughton Unit 3 gas conversion). The second case, P-29PS is a variant of P-29 with the addition of a 400 MW pumped storage project located in northeast Wyoming that is assumed to come online in 2028 following retirement of the Dave Johnston plant.

As seen in Figure 8.25, case P-29 accelerates renewable resources from 2036 to 2032 and adds incremental battery storage resources beginning 2030 relative to case P-45CNW. Under P-29, system costs begin to decrease in 2027, however over the long term, incremental costs for new battery storage resources and market purchases reverse the trend.

Figure 8.25 – P-29 No Gas Case Resource and Cost Compared to P-45CNW

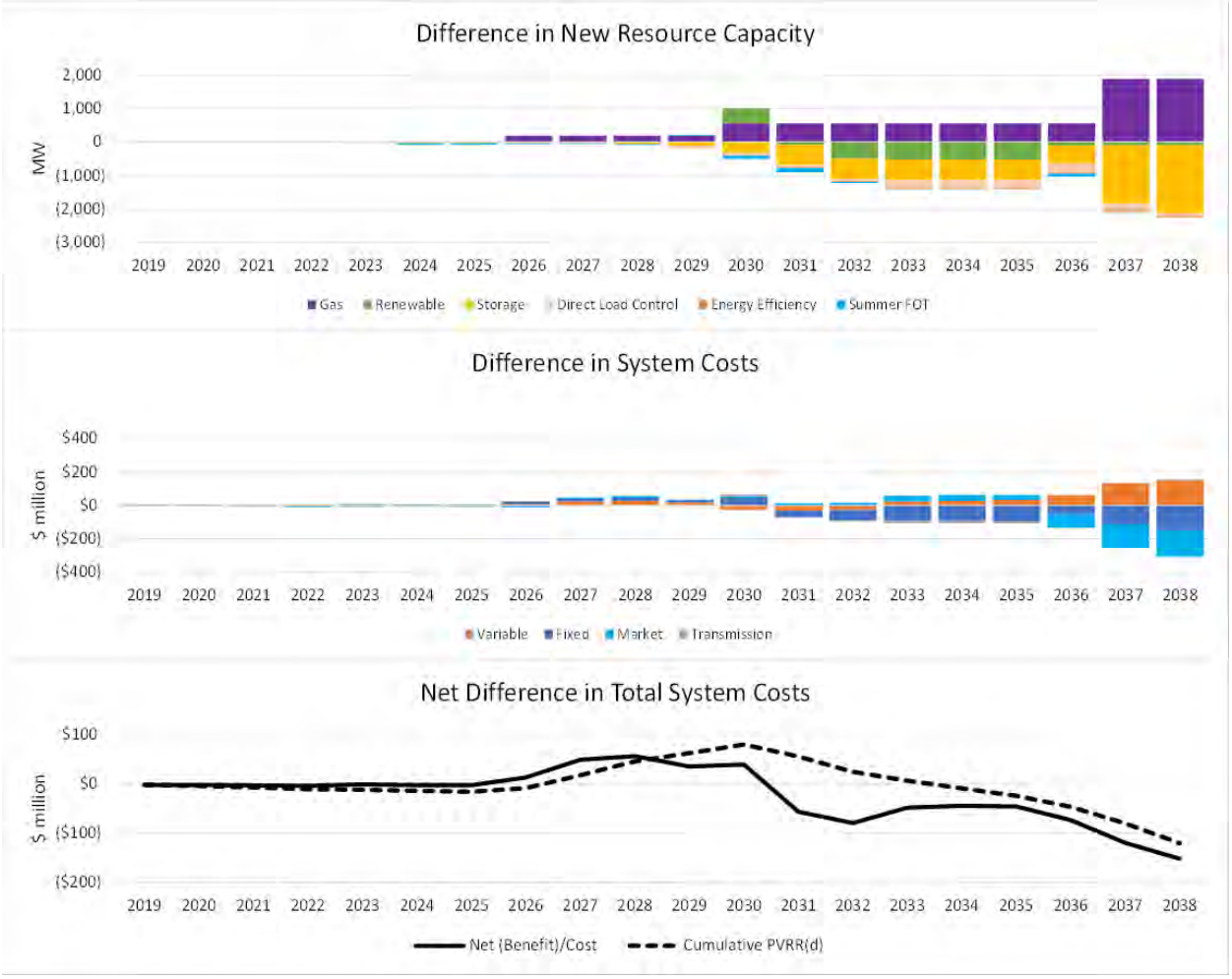


Figure 8.26 summarizes P-29PS portfolio and cost differences compared to P-45CNW, eliminating new gas and adding pumped storage (400 MW) and battery storage (227 MW) in 2028. By the end of the study period, case P-29PS adds an additional 1,575 MW of battery storage. System costs increase beginning 2028 with incremental fixed cost for the storage resources, and added market purchases costs increasingly contribute to the added system costs in the 2036-2038 timeframe.

Table 8.14 summarizes the results of the "No New Natural Gas" cases. Both of these cases result in higher costs than case P-45CNW. Neither case justifies altering selection of Case P-45CNW as the top-performing portfolio.

Figure 8.26 – P-29PS No Gas with Pumped Hydro Storage Compared to P-45CNW

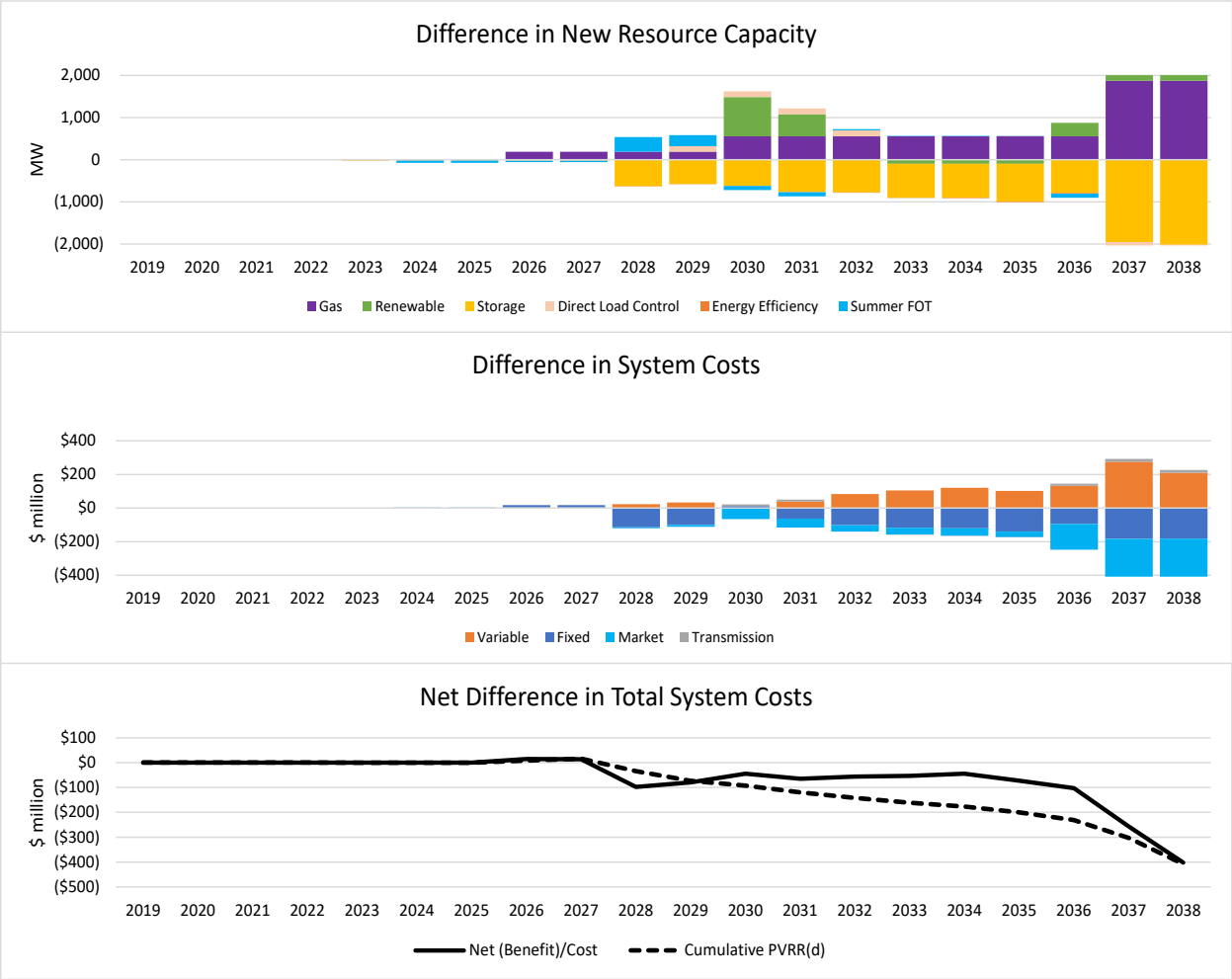


Table 8.14 – No Gas Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CNW	**23,207**	**$0**	**1**	**24,376**	**$0**	**1**	**0.008%**	**0.002%**	**2**	**585,641**	**8,835**	**3**
P29	23,328	$121	2	24,503	$127	2	0.006%	0.000%	1	580,126	3,320	2
P29PS	23,616	$409	3	24,806	$430	3	0.047%	0.040%	3	576,806	0	1

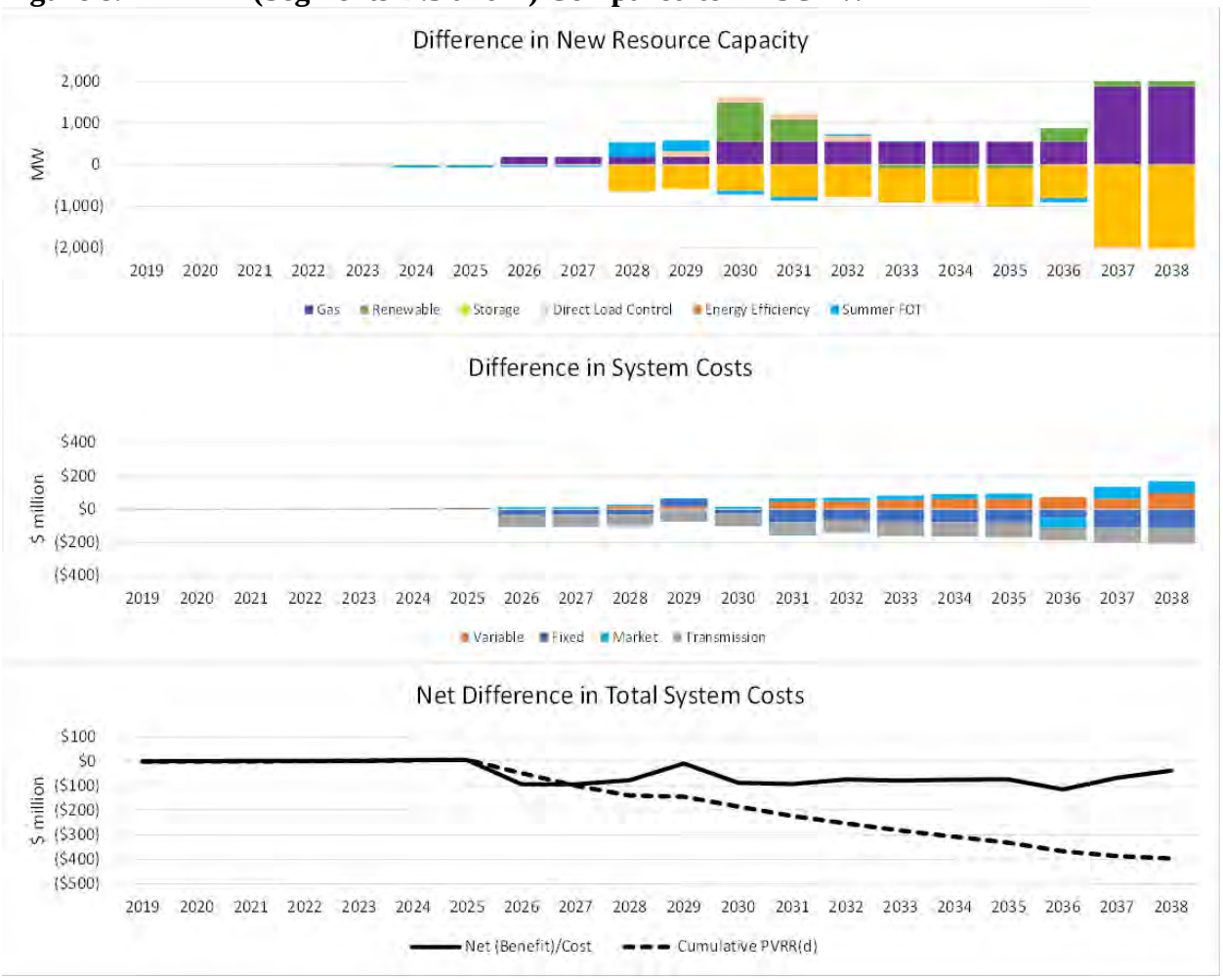
Energy Gateway Transmission Cases

PacifiCorp modeled four Energy Gateway transmission cases, expanding on scenarios defined in previous IRP cycles. The full build-out of all Energy Gateway segments was performed in two cases (P-23 and P-25) to assess the potential value in two different coal retirement scenarios. All of these cases include the endogenous selection of Gateway South in 2024 (as a proxy for year-end 2023). Full case definitions for the Energy Gateway studies are provided in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

P-22 Evaluation

Case P-22 includes the approximately 200 mile Bridger/Anticline-to-Populus Energy Gateway transmission segment (sub-segment D.3). The stochastic mean PVRR of case P-45CNW is $396m lower cost than Case P-22, driven primarily by D.3 transmission project costs where the net portfolio cost impacts are largely offsetting. Case P-45CNW sees higher market, emissions and DSM costs, but reduced capital and fixed operations and maintenance costs that are aligned with the increased proportion of generating resources as opposed to storage resources. Figure 8.27 reports portfolio and cost differences compared to case P-45CNW.

Figure 8.27 – P-22 (Segments D.3 and F) Compared to P-45CNW



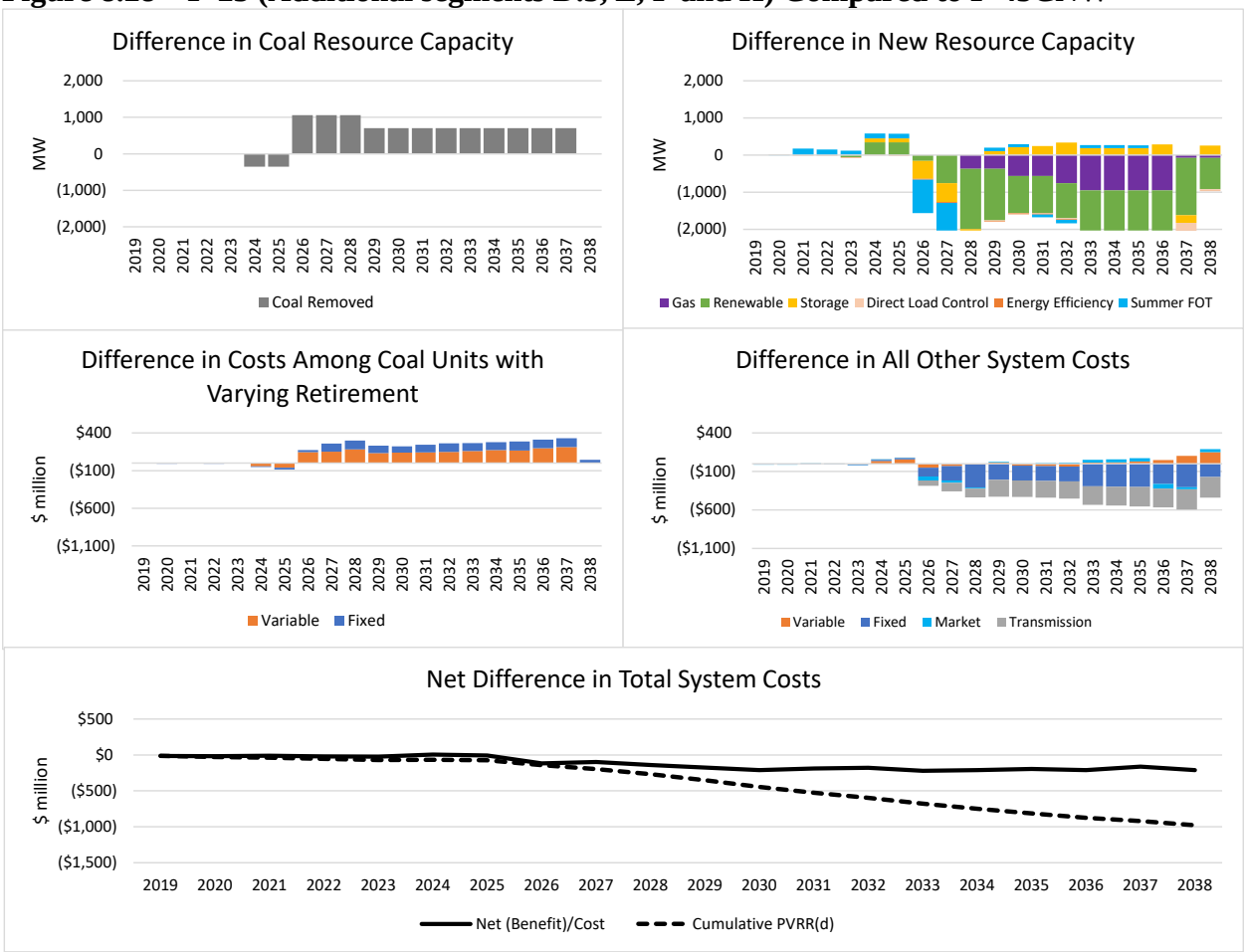
P-23 Evaluation

Relative to case P-36CNW, case P-23 includes the approximately 200 mile Bridger/Anticline-to-Populus transmission sub-segment (D.3), the approximately 500 mile Populus-to-Hemingway transmission segment (E), and the approximately 290 mile Boardman-to-Hemingway segment (H). A variant of stakeholder requested P-36CNW, P-23 features early retirement of the entire Bridger plant in 2025, and also Naughton Units 1-2 in 2025.

As seen in Figure 8.28, the reduction of thermal resources due to highly accelerated retirements causes P-23 to accelerate significant thermal and renewable additions into 2028.

The stochastic mean PVRR of case P-45CNW is $977m lower cost than case P-23, driven primarily by transmission project costs where the net portfolio variable and fixed cost impacts are largely offsetting.

Figure 8.28 – P-23 (Additional segments D.3, E, F and H) Compared to P-45CNW



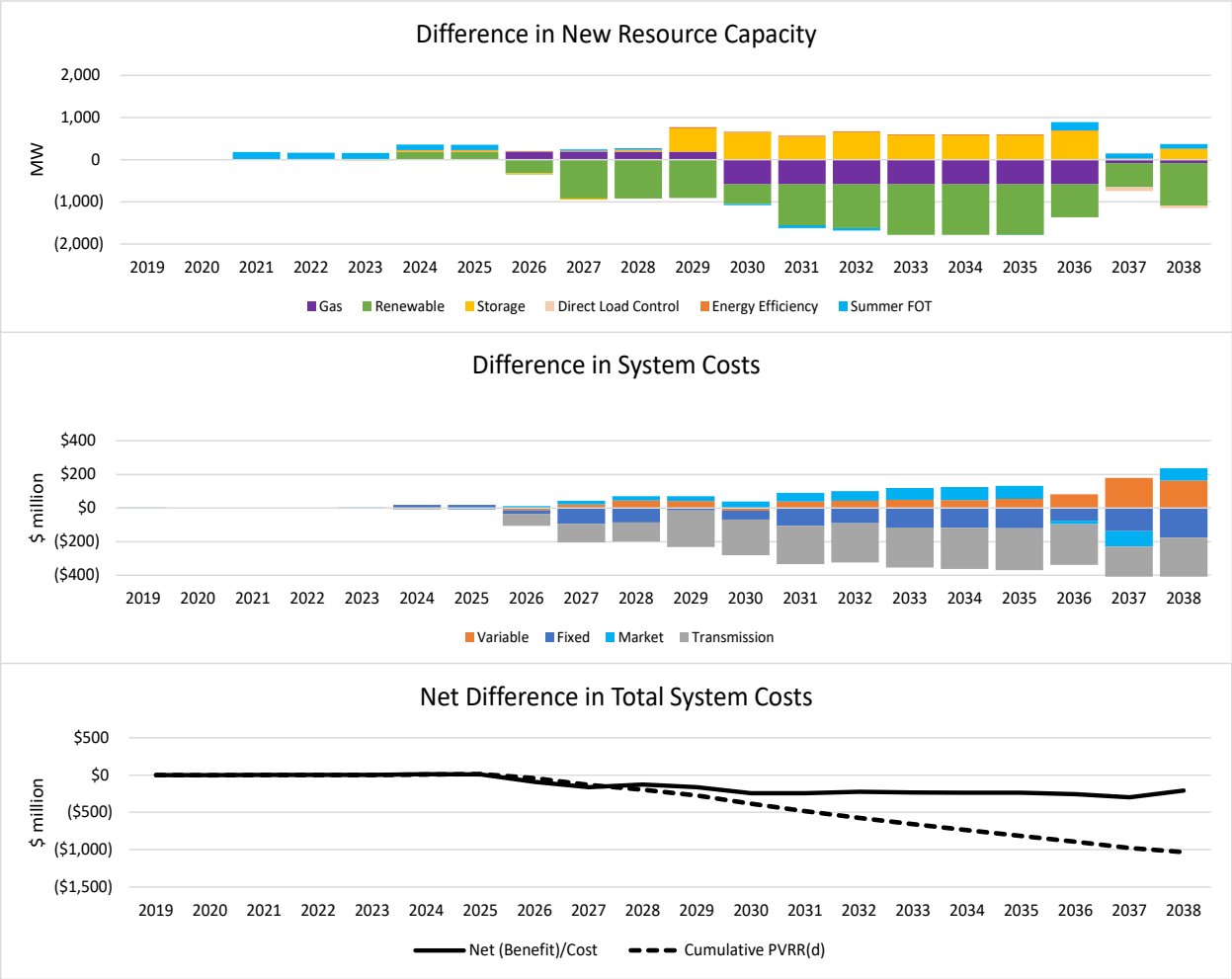
P-25 Evaluation

Case P-25 includes the approximately 200 mile Bridger/Anticline-to-Populus transmission sub-segment (D.3), the approximately 500 mile Populus-to-Hemingway transmission segment (E), and the approximately 290 mile Boardman-to*Hemingway segment (H). Although the Energy Gateway additions match case P-23, P-25 is a variant of P-45CNW.

As seen in Figure 8.29, Gas capacity is accelerated approximately 6 years (~500 MW) into 2030.

The stochastic mean PVRR of case P-45CNW is approximately $1.0b lower cost than case P-25, driven primarily by transmission project costs where the net portfolio variable and fixed cost impacts are largely offsetting.

Figure 8.29 – P-25 (Additional segments D.3, E, F and H) Compared to P-45CNW



P-26 Evaluation

Case P-26 includes the approximately 290 mile Boardman-to-Hemingway transmission segment (H). As seen in Figure 8.30 gas capacity is accelerated approximately 6 years (~500 MW) into 2030.

The stochastic mean PVRR of case P-45CNW is approximately $98m lower cost than case P-26. In Table 8.15 case P-26 ranks second among gateway cases in 3 of 4 categories, including stochastic mean, risk-adjusted PVRR and low ENS. These results are promising, and signal that with motivated project partners and potentially significant regional reliability benefits, updated modeling that can better capture the value of this project will ultimately support a business case to move forward with the project. Consequently, PacifiCorp has included an action item in its 2019 IRP action plan to continue to evaluate and support the Boardman-to-Hemmingway project.

Table 8.15 reports a summary of the Energy Gateway cases.

Figure 8.30 – P-26 (Segments F and H) Compared to P-45CNW

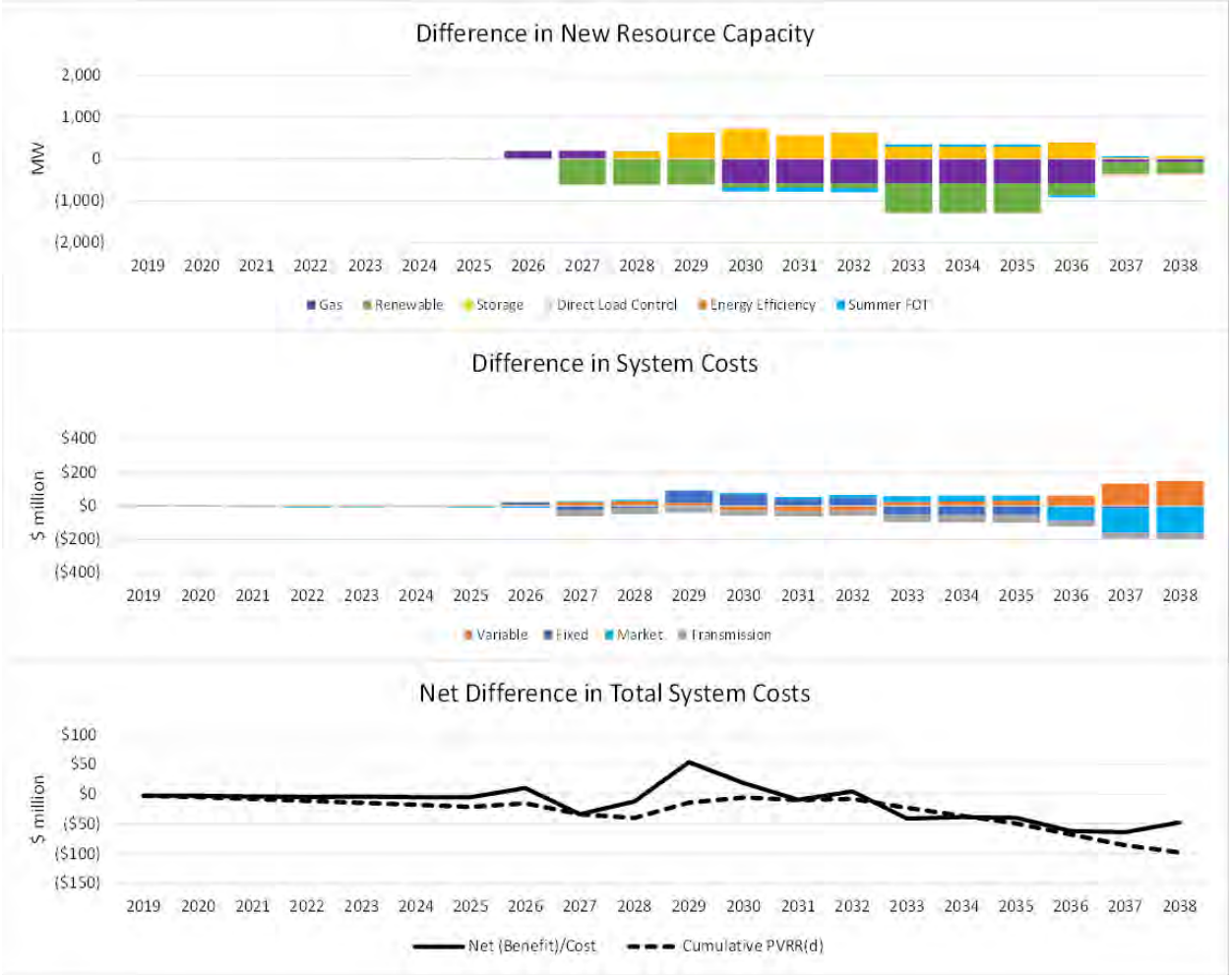


Table 8.15 – Gateway Case Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CNW	**23,207**	$0	1	**24,376**	$0	1	**0.008%**	0.002%	5	**585,641**	40,831	5
P-26	23,305	$98	2	24,479	$104	2	0.006%	0.000%	2	580,126	35,315	3
P-22	23,603	$396	3	24,792	$416	3	0.007%	0.001%	4	581,028	36,217	4
P-23	24,184	$977	4	25,402	$1,026	4	0.007%	0.001%	3	544,811	0	1
P-25	24,239	$1,032	5	25,460	$1,084	5	0.006%	0.000%	1	580,014	35,204	2

Gateway Studies Conclusions

While the results above did not compel PacifiCorp to alter its selection of case P-45CNW as the top-performing portfolio, the company remains confident that additional Energy Gateway segments will provide incremental regional and customer benefits with an ongoing transition to the regional resource mix and as new markets develop.

As discussed above, case P-26, which includes the Boardman-to-Hemingway transmission line, shows significant potential for producing customer benefits. This project has motivated partners and is expected to provide incremental benefits not captured in the current analysis that can be further explored in future IRPs and IRP Updates. Consequently, PacifiCorp will remain an active participate in the ongoing development of this project and has included an action item in its action plan to continue its partnership in this project. Some of the incremental benefits of Boardman-to-Hemmingway not captured in the analysis above include:

- Connecting geographical diversity to help balance the intermittency of resources like wind and solar, to help meet clean-energy standards and bolsters resource adequacy.
- Decreasing market reliance by providing incremental infrastructure that can connect additional resources to load.
- Improved reliability by increasing ability to share operating reserves among utilities and providing additional source for energy to flow.
- Help alleviate transmission congestion.
- Improved access to participate in the Energy Imbalance Market and generate customer benefits.

PacifiCorp has also included an action item to continue permitting the Energy Gateway transmission plan, as it is anticipated these additional segments will also provide incremental value that can continue to be evaluated in future IRPs and IRP Updates.

Final Preferred Portfolio Selection

Case P-45CNW entered the final evaluations as the top candidate for preferred portfolio, and for purposes of the 2019 IRP, the "No New Natural Gas" and Energy Gateway cases did not change P-45CNW's top status. Consequently, PacifiCorp selected the resource portfolio from case P-45CNW as the 2019 IRP preferred portfolio.

The 2019 IRP Preferred Portfolio

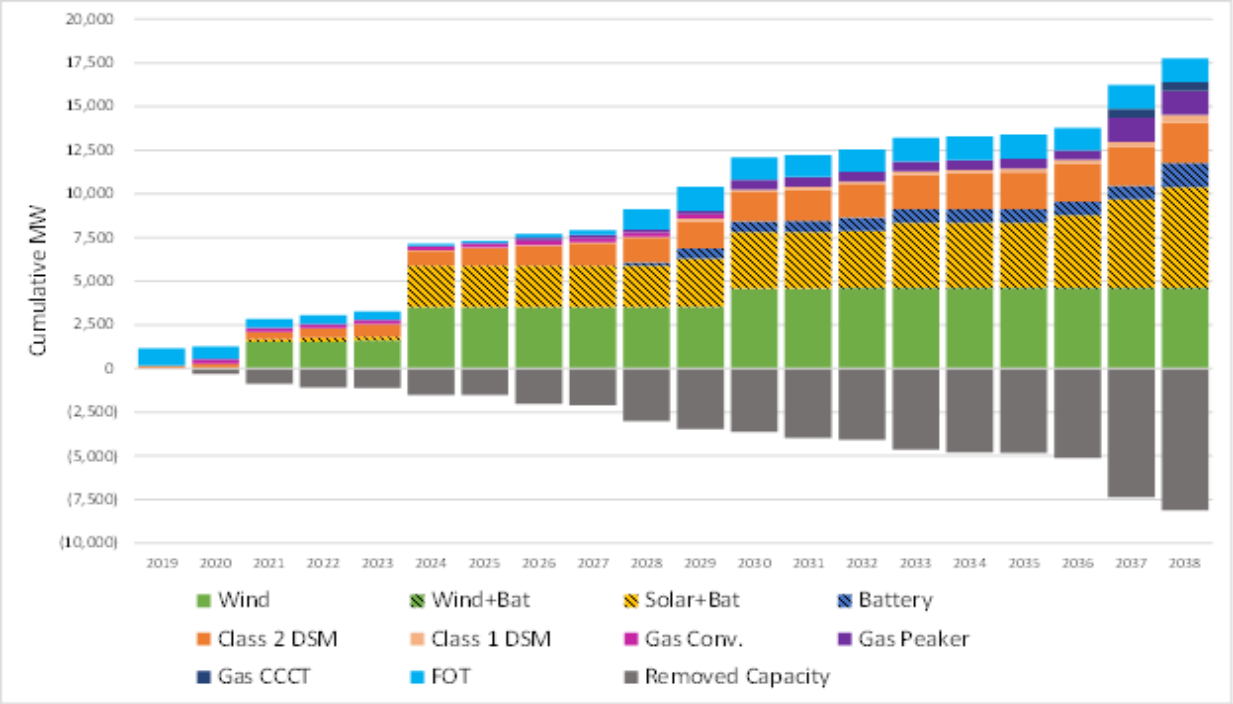
PacifiCorp's selection of the 2019 IRP preferred portfolio is supported by comprehensive data analysis and an extensive stakeholder-input process. Figure 8.31 shows that PacifiCorp's preferred portfolio continues to include new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, and for the first time, significant battery storage resources. By the end of 2023, the preferred portfolio includes nearly 3,000 MW of new solar resources and more than 3,500 MW of new wind resources, inclusive of resources that will come online by the end of 2020 that were not in the 2017 IRP.[3] The preferred portfolio also includes nearly 600 MW of battery storage capacity (all collocated with new solar resources), and over 700 MW of incremental energy efficiency and new direct load control resources.

Over the 20-year planning horizon, the preferred portfolio includes more than 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, more than 2,800 MW of battery storage (nearly 1,400 MW of which are stand-alone storage resources starting in 2028), and more

[3] *Id.*

than 2,700 MW of incremental energy efficiency and new direct load control resources.[4] While the preferred portfolio includes new natural gas peaking capacity beginning 2026, this falls outside of the 2019 IRP action plan window, which provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain long-term system reliability.

Figure 8.31 – 2019 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes a 400-mile transmission line known as Gateway South, planned to come online by the end of 2023, that will connect southeastern Wyoming and northern Utah. The new transmission line is in addition to the 140-mile Gateway West transmission line in Wyoming currently under construction as part of PacifiCorp's Energy Vision 2020 initiative. The preferred portfolio further includes near-term transmission upgrades in Utah and Washington. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources. Table 8.16 summarizes the incremental transmission projects included in the 2019 IRP preferred portfolio, and Table 8.17 summarizes the total amount of initial capital investment required to deliver incremental transmission and resource investments through the 20-year planning period of the 2019 IRP.

[4] *Id.*

Table 8.16 – Transmission Projects Included in the 2019 IRP Preferred Portfolio*

Year	Resource(s)	From	To	Description
2023	69 MW Wind (2023) 231 MW Solar (2024)	Within Southern UT Transmission Area		Enables 300 MW of interconnection: UT Valley 345-138 kV + 138 kV reinforcement ($8m)
2024	354 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 1 ($0)
2024	674 MW Solar (2024)	Within Northern UT Transmission Area		Enables 600 MW of interconnection: Northern UT 345 kV reinforcement ($30m)
2024	1,920 MW Wind (2024)	Aeolus WY	UT North	Enables 1,920 MW of interconnection with 1,700 MW of TTC: Energy Gateway South ($1,752m)
2024	395 MW Solar (2024) 10 MW Wind (2029)	Within Yakima WA Transmission Area		Enables 405 MW of interconnection: local reinforcement ($3m)
2024	359 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 2 ($0)
2030	1,040 MW Wind (2030) 60 MW Wind (2032)	Goshen ID	UT North	Enables 1,100 MW of interconnection with 800 MW of TTC ($254m)
2030	500 MW Solar (2030)	Within Southern UT Transmission Area		Enables 500 MW of interconnection: UT Valley local area reinforcement ($206m)
2033	475 MW Solar (2033)	Within Southern OR Transmission Area		Enables 475 MW of interconnection: Medford area 500 kV-230 kV reinforcement ($102m)
2036	419 MW Solar (2036)	Yakima WA	Southern OR	Enables 430 MW of interconnection with 450 MW of TTC: Yakima WA to Bend OR 230 kV ($255m)
2037	909 MW Solar (2037)	Southern UT	Northern UT	Reclaimed transmission upon retirement of Huntington 1-2 ($0)
2037	443 MW Gas (2037)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement ($40m)
2037	370 MW Gas (2037)	Within Southwest WY Transmission Area		Enables 500 MW of interconnection: separation of double circuit 230 kV lines ($39m)
2038	702 MW Solar (2038)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 3-4 ($0)

*Note: 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.

Table 8.17 – Total Initial Capital to Deliver Preferred Portfolio Transmission and Resource Investments ($ million)

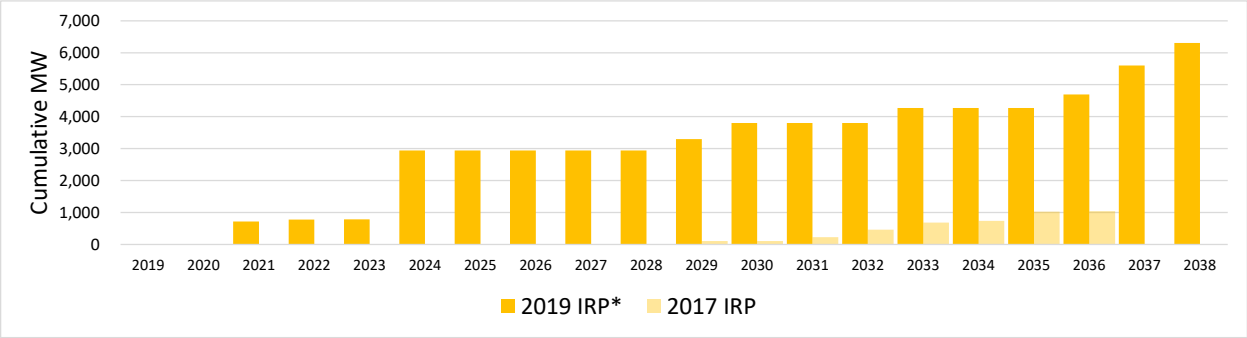
State	Transmission	Resources	Total
Idaho	$254	$1,659	$1,912
Oregon	$264	$2,540	$2,804
Utah	$1,004	$3,466	$4,470
Washington	$136	$1,509	$1,644
Wyoming	$765	$5,376	$6,141
Colorado	$370	$0	$370
Total	$2,792	$14,550	$17,342

New Solar Resources

The 2019 IRP preferred portfolio includes more than 3,000 MW of new solar by the end of 2023, which accounts for resources that will come online by the end of 2020 but not in the 2017 IRP, and more than 6,300 MW of new solar by 2038 as shown in Figure 8.32.[5]

[5] *Id.*

Figure 8.32 – 2019 IRP Preferred Portfolio New Solar Capacity*

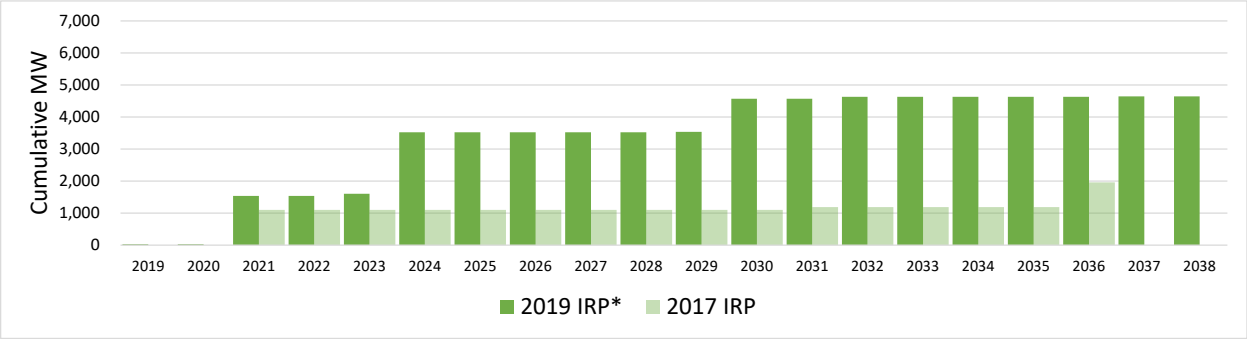


*Note: 2019 IRP solar capacity shown in the figure includes 559 MW of contracted new solar (all power-purchase agreements) that was not identified in the 2017 IRP. These resources will be online by the end of 2020 and are shown in the first full year of operation (the year after year-online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Wind Resources

As shown in Figure 8.33, PacifiCorp's 2019 IRP preferred portfolio includes more than 3,500 MW of new wind generation by the end of 2023, which accounts for new resources that will come online by the end of 2020 but not in the 2017 IRP, and more than 4,600 MW of new wind by 2038.[6]

Figure 8.33 – 2019 IRP Preferred Portfolio New Wind Capacity*



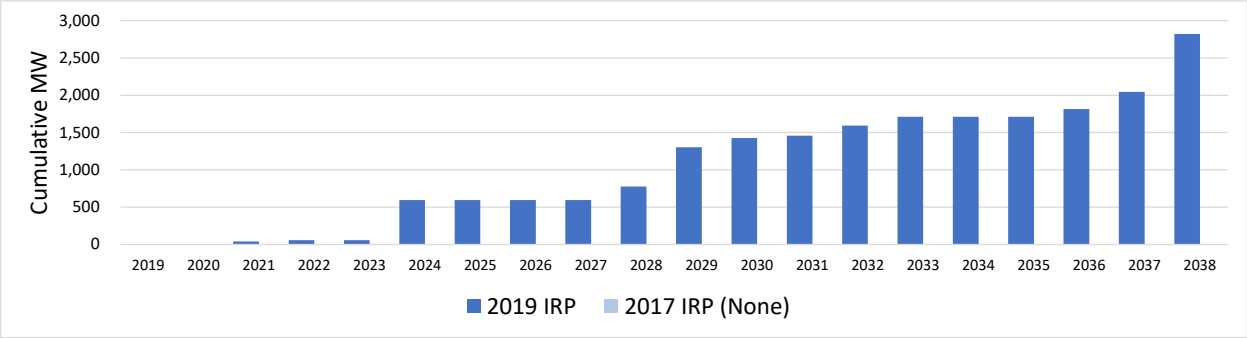
*Note: 2019 IRP wind capacity shown in the figure includes 1,533 MW of contracted new wind (21 percent power-purchase agreements) that was either identified in the 2017 IRP and is under construction or that was not identified in the 2017 IRP and is under contract. These resources will come on-line by the end of 2020. These resources are shown in the first full year of operation (the year after year-end online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Storage Resources

This is the first PacifiCorp IRP that identifies new battery storage resources as part of its least-cost, least-risk portfolio. As shown in Figure 8.34, PacifiCorp's 2019 IRP preferred portfolio includes nearly 600 MW of battery storage by the end of 2023. All of the storage resources planned through this period are paired with new solar generation. The plan also adds nearly 1,400 MW of stand-alone storage resources starting in 2028.

[6] *Id.*

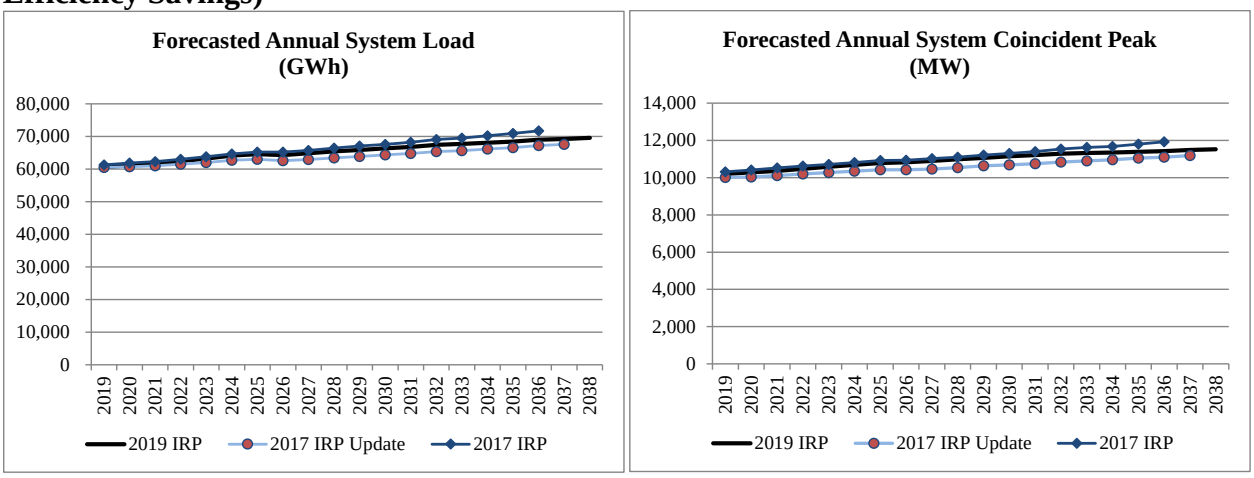
Figure 8.34 – 2019 IRP Preferred Portfolio New Storage Capacity



Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and direct load control 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 8.35 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2017 IRP and 2017 IRP Update. On average, forecasted system load is up 2.4 percent and forecasted coincident system peak is up 3.4 percent when compared to the 2017 IRP Update. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 0.73 percent for load and 0.64 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from data centers driving up the commercial forecast and an increase the residential forecast.

Figure 8.35 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)

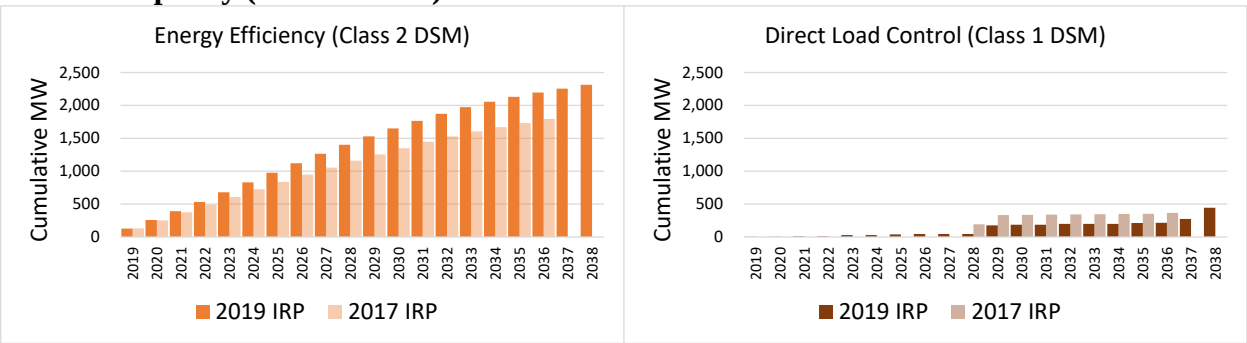


DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 8.36 compares total energy efficiency savings in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio.

In addition to continued investment in energy efficiency programs, the preferred portfolio continues to show a role for incremental direct load control programs with total capacity reaching

444 MW by the end of the planning period. The chart to the right in Figure 8.36 compares total incremental capacity of direct load control program capacity in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio and does not include capacity from existing programs.

Figure 8.36 – 2019 IRP Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 8.37 shows that the 2019 IRP's base case forecast for natural gas and power prices has increased from those in the 2017 IRP and 2017 IRP Update. 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 2019 IRP are primarily driven by the assumption of a carbon price that is higher and starts earlier (2025) than what was assumed in the 2017 IRP Update (2030).[7] Moreover, the 2019 IRP assumed higher natural gas prices than either the 2017 IRP or 2017 IRP Update as Henry Hub, in particular, is boosted by increasing LNG exports. While not shown in the figure below, the 2019 IRP also evaluated low and high price scenarios when evaluating the cost and risk of different resource portfolios.

Figure 8.37 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

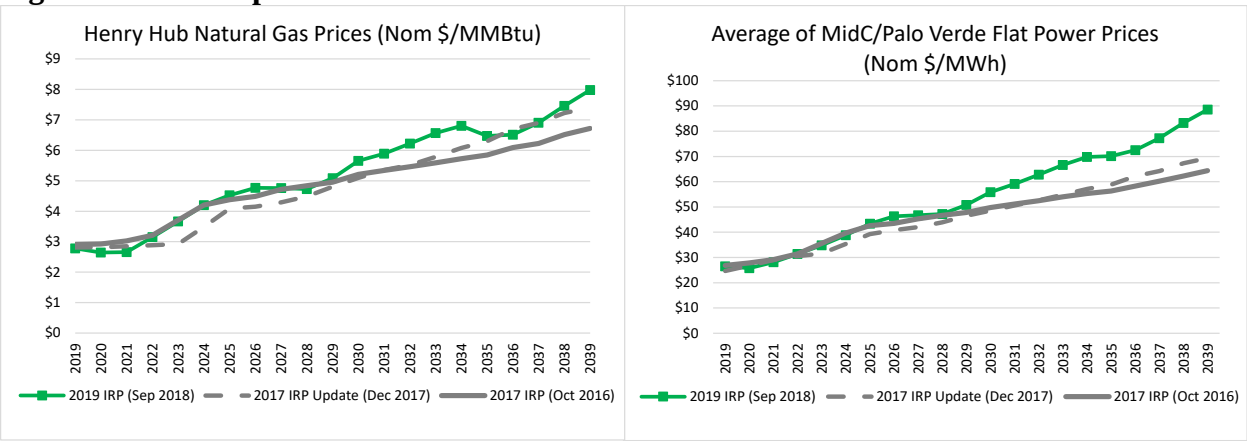
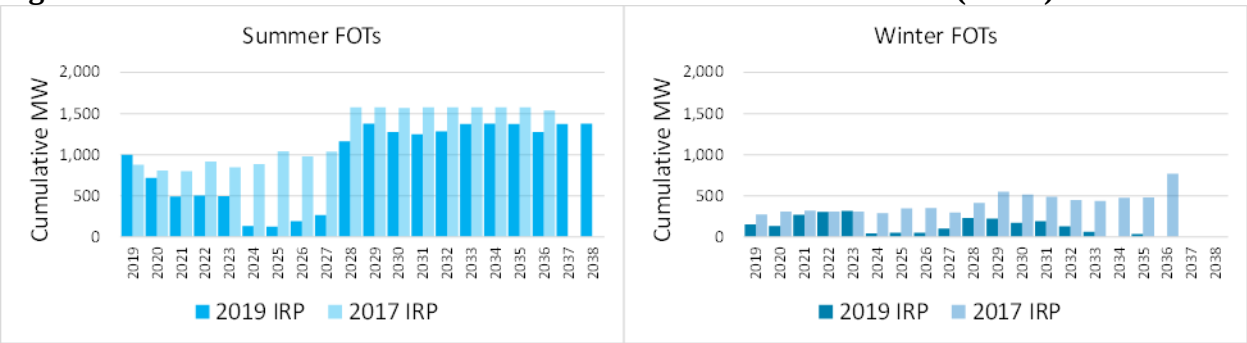


Figure 8.38 shows an overall decline in reliance on wholesale market firm purchases in the 2019 IRP preferred portfolio relative to the market purchases included in the 2017 IRP preferred portfolio. In particular, reliance on market purchases during summer peak periods averages 366 MW per year over the 2020-2027 timeframe—down 60 percent from market purchases identified in the 2017 IRP preferred portfolio. This reduction in market purchases coincides with the period

[7] The 2017 IRP did not assume a carbon price but, instead, reflected implementation of the Clean Power Plan.

over which there are resource adequacy concerns in the region. While market purchases increase beyond 2027, 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.

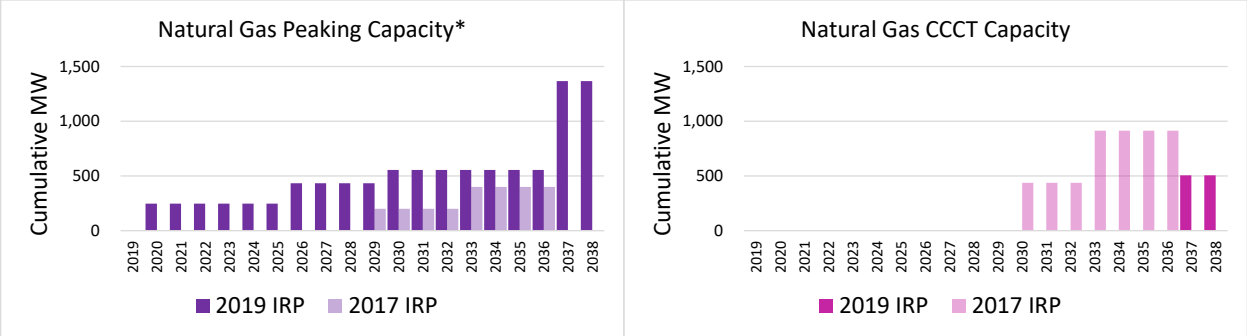
Figure 8.38 – 2019 IRP Preferred Portfolio Front Office Transactions (FOTs)



Natural Gas Resources

In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost reliable resource for meeting load and reliability requirements. New natural gas peaking resources appear in the preferred portfolio starting in 2026, which is outside the action-plan window. This provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain system reliability long into the future.

Figure 8.39 – 2019 IRP Preferred Portfolio Natural Gas Peaking and Combined Cycle Capacity*



* Note: 2019 IRP natural gas peaking capacity includes the conversion of Naughton Unit 3 to natural gas in 2020 (247 MW).

Coal Retirements

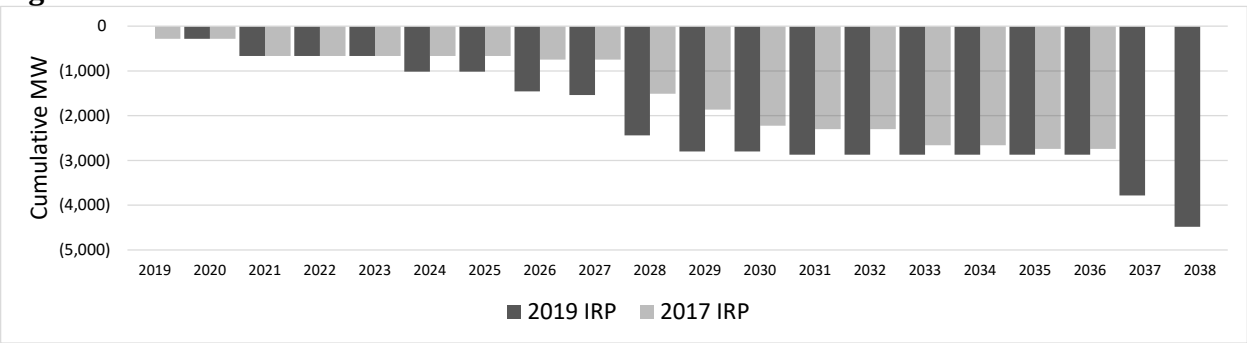
Coal resources have been an important resource in PacifiCorp's resource portfolio. Changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums) has allowed the company to buy increasingly low-cost, zero-emissions renewable energy from market participants, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as those 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 24 coal units currently serving PacifiCorp

customers, the preferred portfolio includes retirement of 16 of the units by 2030 and 20 of the units by the end of the planning period in 2038. As shown in Figure 8.40, coal unit retirements in the 2019 IRP preferred portfolio will reduce coal-fueled generation capacity by over 1,000 MW by the end of 2023, nearly 1,500 MW by the end of 2025, nearly 2,800 MW by 2030, and nearly 4,500 MW by 2038.

Coal unit retirements scheduled under the preferred portfolio include:

- 2019 = Naughton Unit 3 (same as 2017 IRP), converted to natural gas in 2020
- 2020-2023 = Cholla Unit 4 (same as 2017 IRP)
- 2023 = Jim Bridger Unit 1 (instead of 2028 in the 2017 IRP)
- 2025 = Naughton Units 1-2 (instead of 2029 in the 2017 IRP)
- 2025 = Craig Unit 1 (same as 2017 IRP)
- 2026 = Craig Unit 2 (instead of 2034 in the 2017 IRP)
- 2027 = Dave Johnston Units 1-4 (same as 2017 IRP)
- 2027 = Colstrip Units 3-4 (instead of 2046 in the 2017 IRP)
- 2028 = Jim Bridger Unit 2 (instead of 2032 in the 2017 IRP)
- 2030 = Hayden Units 1-2 (same as 2017 IRP)
- 2036 = Huntington Units 1-2 (same as 2017 IRP)
- 2037 = Jim Bridger Units 3-4 (same as 2017 IRP)

Figure 8.40 – 2019 IRP Preferred Portfolio Coal Retirements*



* Note: Coal 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.

Carbon Dioxide Emissions

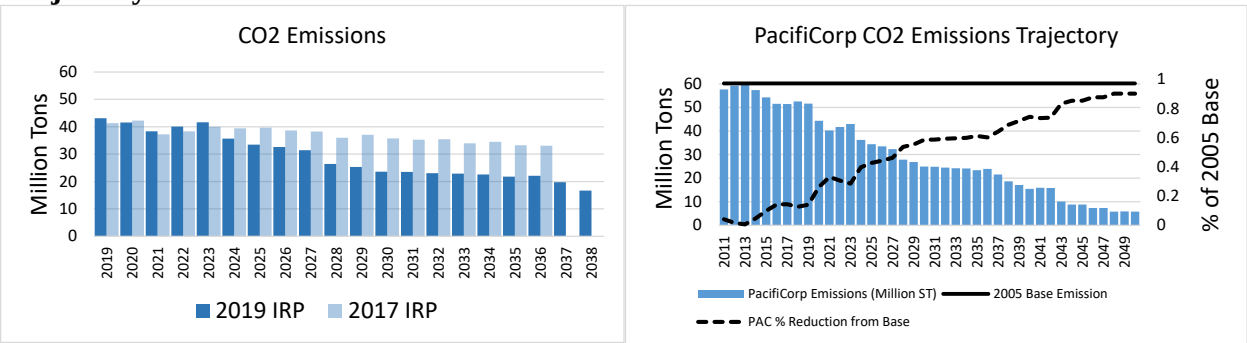
The 2019 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors, including PacifiCorp's participation in the Energy Imbalance Market (EIM), which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going expansion of renewable resources and transmission; and Regional Haze compliance that capitalizes on flexibility.

The chart on the left in Figure 8.41 compares projected annual CO_2 emissions between the 2019 IRP and 2017 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales, and in 2025, annual CO_2 emissions are down sixteen percent relative to the 2017 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative

to the 2017 IRP preferred portfolio, and down 35 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.1 million tons in 2019 to 16.7 million tons in 2038—a 61.3 percent reduction.

The chart of the right in Figure 8.41 includes historical data, assigns emissions at a rate of 0.4708 tons/megawatt hours (MWh) to market purchases (with no credit to market sales), and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline (a ubiquitous baseline year in the industry), system CO_2 emissions are down 43 percent in 2025, 59 percent in 2030, 61 percent in 2035, 74 percent in 2040, 85 percent in 2045, and 90 percent in 2050.

Figure 8.41 – 2019 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Emissions Trajectory*



*Note: PacifiCorp CO_2 Emissions Trajectory reflects actual emissions through 2018 from owned facilities, specified sources and unspecified sources. From 2019 through the end of the twenty-year planning period in 2038, emissions reflect those from the 2019 IRP preferred portfolio with market purchases assigned the California Air Resources Board default emission factor (0.4708 tons/MWh) – emissions from sales are not removed. Beyond 2038, emissions reflect the rolling average emissions of each resource from the 2019 IRP preferred portfolio through the life of the resource.

Renewable Portfolio Standards

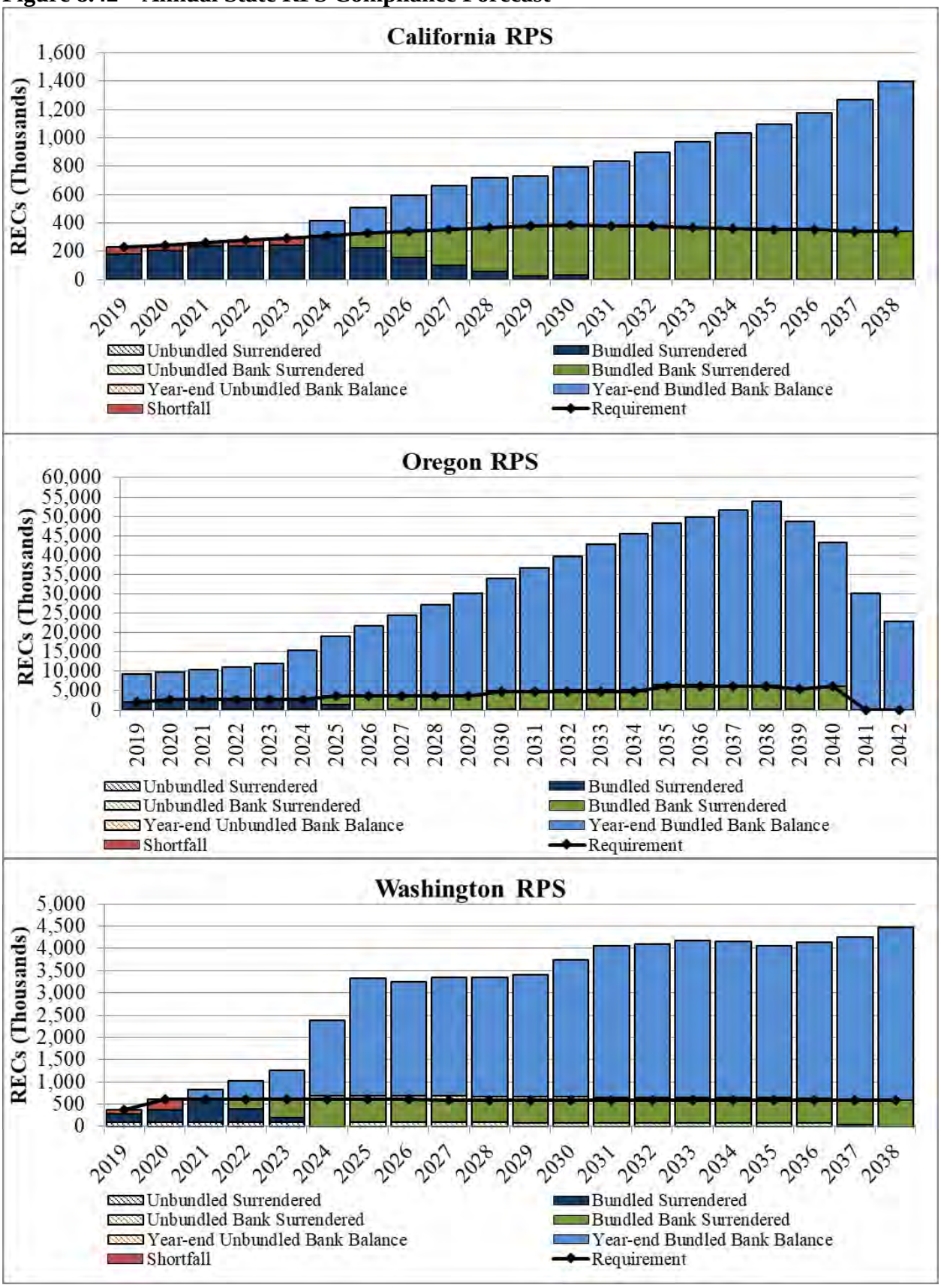
Figure 8.42 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are not included in the preferred portfolio as cost-effective system resources and 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 2038 with the addition of new renewable resources and transmission in the 2019 IRP preferred portfolio. The California RPS compliance position is also improved by the addition of new renewable resources and transmission in the 2019 IRP preferred portfolio but requires a small amount of unbundled renewable energy credit (REC) purchases under 150 thousand RECs per year to achieve compliance through Compliance Period 4. Washington RPS compliance is achieved with the benefit of repowered wind assets located in the west side, Marengo, Leaning Juniper and Goodnoe Hills, increased system renewable resources contributing to the west side beginning 2021[8], and unbundled REC purchases under 300 thousand

[8] PacifiCorp will propose the Multi-State Protocol allocation methodology in a December 13, 2019 Washington general rate case (GRC) filing. The methodology would allocate a system generation share of all non-emitting system resources to Washington. The 2019 IRP Annual State RPS Compliance Forecast reflected in Figure 8.42 reflects PacifiCorp's proposal to be filed in the rate case starting in 2021. Upon approval, the effective date of the new allocation methodology would be January 1, 2021.

RECs per year through 2021. Under current allocation mechanisms, Washington customers do not benefit from the new renewable resources added to the east side of PacifiCorp's system. While not shown in Figure 8.42, 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 2019 IRP preferred portfolio.

Figure 8.42 – Annual State RPS Compliance Forecast



Capacity and Energy

Figure 8.43 displays how preferred portfolio resources meet PacifiCorp's capacity needs over time. Through 2038, PacifiCorp meets its capacity needs, including a 13 percent target planning reserve margin, through incremental acquisition of wind and solar resources, enabled by investment in transmission infrastructure, battery storage resources, new DSM, natural gas and wholesale power market purchases.

Figure 8.43 – Meeting PacifiCorp's Capacity Needs with Preferred Portfolio Resources

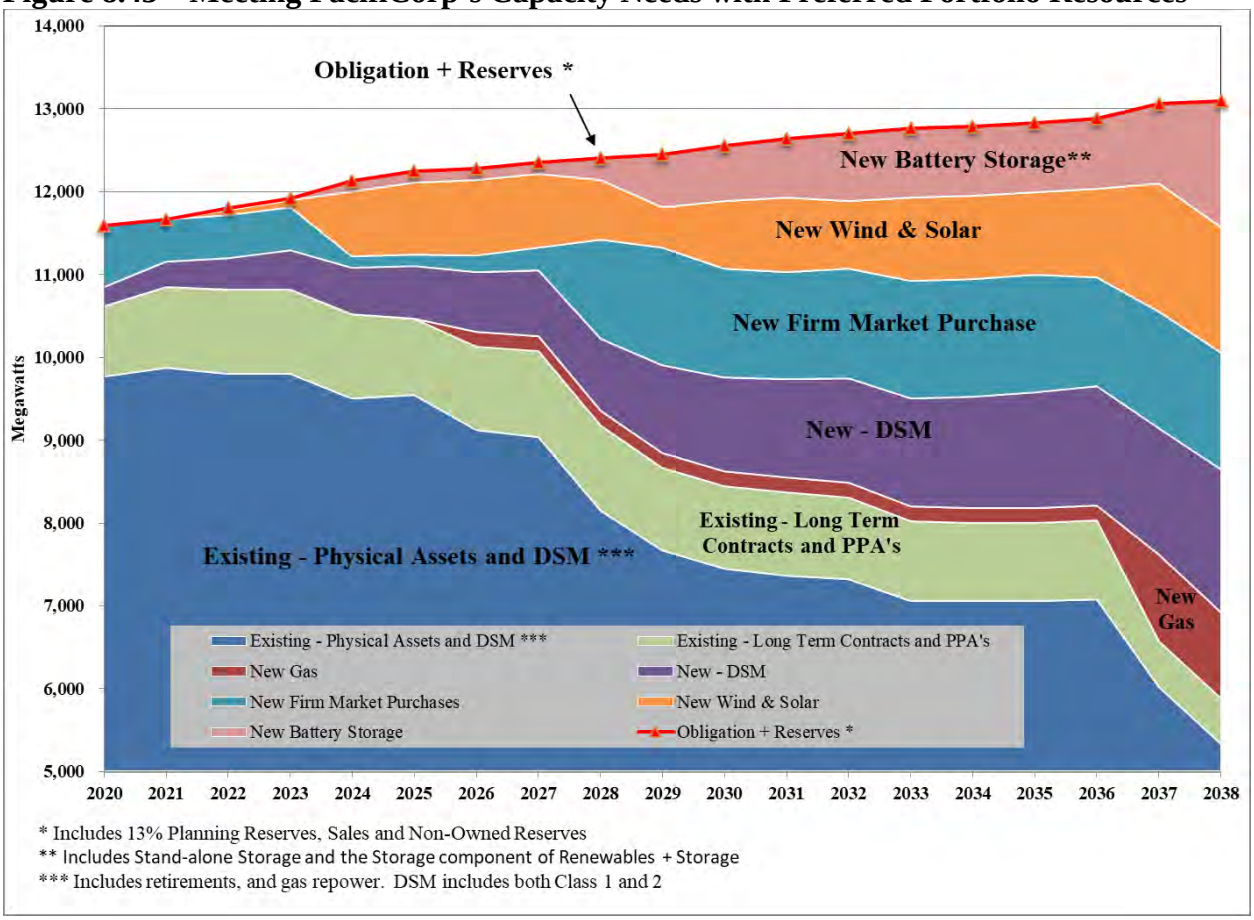


Figure 8.44 and Figure 8.45 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[9] On an energy basis, coal generation drops below 40 percent by 2025, falls to 22 percent by 2030, and declines to less than 6 percent by the end of the planning period. On a capacity basis, coal resources drop to 24 percent by 2025, fall to 13 percent by 2030, and decline to 5 percent by the end of the

[9]The projected PacifiCorp 2019 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2019 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable resources, DSM resources, and to a smaller extent later in the plan, new natural gas resources.

Figure 8.44 – Projected Energy Mix with Preferred Portfolio Resources

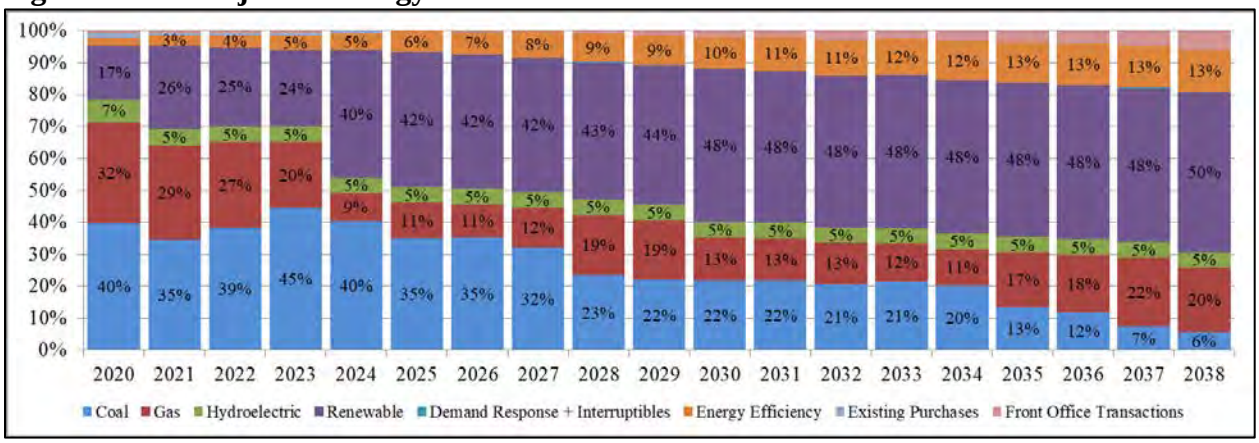
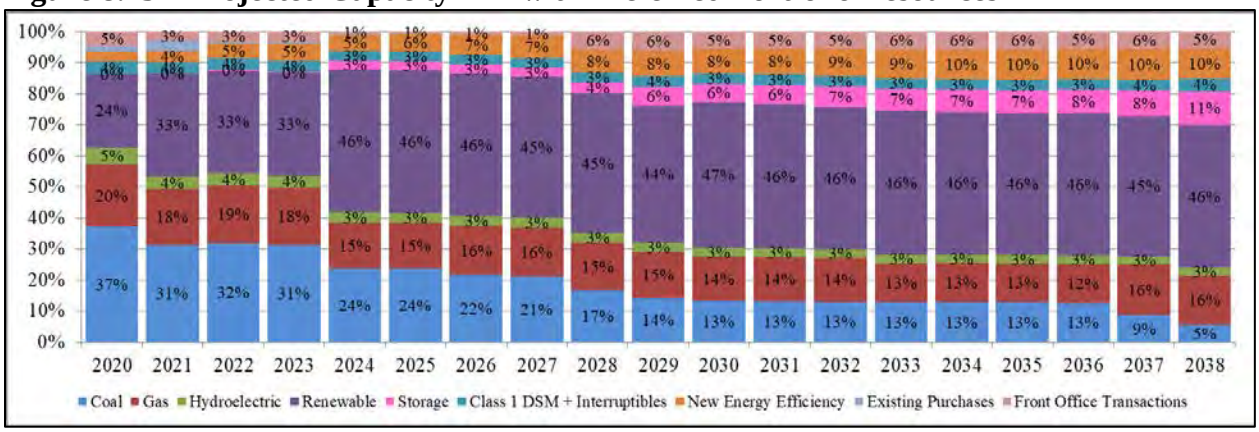


Figure 8.45 – Projected Capacity Mix with Preferred Portfolio Resources



Detailed Preferred Portfolio

Table 8.18 provides line-item detail of PacifiCorp's 2019 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 20-year planning horizon. Table 8.19 and Table 8.20 show 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 8.21 and Table 8.22 show 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 8.18 – PacifiCorp's 2019 IRP Preferred Portfolio (The 2019 Preferred Portfolio includes repowering 905 MW of existing wind resources, not shown in the table)

		Capacity (MW)																				Resource Totals 1/	
	P45CNW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Espire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Espire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	370	-	185	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,040	-	-	-	-	-	-	-	-	-	1,040
	Wind, UT	-	-	-	-	69	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	69	69
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	60
	Total Wind	-	-	-	-	69	1,920	-	-	-	-	-	1,040	-	60	-	-	-	-	-	-	1,989	3,089
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	231	-	-	-	-	-	500	-	-	-	-	-	-	-	-	231	731
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	3	674	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	3	904	-	-	-	-	-	500	-	-	-	-	-	-	909	-	1,131	2,540
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	37.3
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	1.2	-	6.7
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	3.7	10.5	136.5	44.6	354.1
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	68	67	65	65	62	57	56	52	52	48	36	32	25	22	23	656	1,058
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	18	17	16	15	13	12	11	9	8	7	5	5	146	248
	Energy Efficiency Total	74	83	85	88	92	92	91	90	90	87	80	77	72	70	65	49	45	35	30	32	870	1,423
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195	-	195.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	30.0	-	-	-	-	-	-	150.0	-	180.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	88	300	199	174	206	298	300	300	300	300	300	9	138
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Espire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Espire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind+Storage, YK	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	11	-	-	20
	Total Wind	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	11	-	-	20
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	395	-	-	-	-	-	-	-	-	-	-	-	419	-	-	395	815
	Total Solar	-	-	-	-	-	1,249	-	-	-	-	359	-	-	-	475	-	-	419	-	702	1,249	3,205
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	48.8	32.1	-	90.2
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	42	41	46	43	41	41	38	35	32	31	30	26	26	25	25	24	23	405	680
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	11	10	9	9	8	8	6	6	5	4	4	111	179
	Energy Efficiency Total	52	49	48	55	55	59	56	54	54	51	46	43	42	40	35	33	33	30	29	28	533	892
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	210	-	-	60	-	-	-	-	-	180	-	450
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	75	45	-	-	-	-	-	-	-	-	-	75	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	75	-	-	60	-	-	-	-	-	60	-	195
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	131	126	191	264	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	977	1,074	1,075	500	782
	FOT West - Winter	151	131	268	303	314	44	51	53	100	232	222	173	192	128	63	-	35	-	-	-	165	123
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	132	299	206	237	4,225	155	336	143	318	1,063	2,038	144	303	574	82	93	488	2,355	1,530		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	175	177	244	364	1,394	1,597	1,447	1,441	1,409	1,435	1,375	1,410	1,277	1,374	1,375		
	Total Annual Additions	1,279	982	1,060	1,012	1,049	4,400	333	580	507	1,712	2,661	3,485	1,584	1,712	2,010	1,457	1,503	1,765	3,729	2,905		

Table 8.19 – Preferred Portfolio Summer Capacity Load and Resource Balance (2020-2029)

Calendar Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
East										
Thermal	5,963	5,634	5,634	5,634	5,634	5,634	5,217	5,140	4,481	4,481
Hydroelectric	74	74	74	74	74	74	74	74	74	74
Renewable	406	843	859	866	876	906	898	891	827	718
Purchases	242	215	215	215	215	115	115	115	115	115
Qualifying Facilities	891	666	665	665	617	619	621	620	610	590
Demand Response	323	323	323	323	323	323	323	323	323	323
Sales	(655)	(175)	(175)	(175)	(148)	(148)	(66)	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	271	(140)	(137)	(134)	(392)	(388)	(322)	(292)	307	365
East Existing Resources	**7,481**	**7,405**	**7,423**	**7,433**	**7,163**	**7,100**	**6,826**	**6,836**	**6,703**	**6,632**
Front Office Transactions	0	0	0	0	0	0	0	0	90	309
Gas	0	0	0	0	0	0	179	179	179	179
Wind	0	0	0	15	324	339	345	342	309	255
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	63	72	214	244	258	251	187	88
Demand Response	4	11	11	28	28	36	43	43	43	162
Other	1	1	1	1	1	1	1	1	1	1
East Planned Resources	**5**	**12**	**74**	**117**	**568**	**620**	**826**	**816**	**810**	**994**
East Total Resources	**7,486**	**7,416**	**7,498**	**7,550**	**7,731**	**7,720**	**7,652**	**7,652**	**7,512**	**7,626**
Load	7,039	7,108	7,185	7,276	7,405	7,442	7,460	7,523	7,604	7,678
Private Generation	(125)	(166)	(173)	(176)	(202)	(188)	(195)	(204)	(218)	(233)
Existing Resources:										
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
New Resources:										
Energy Efficiency	(93)	(140)	(190)	(242)	(293)	(344)	(395)	(446)	(495)	(540)
East obligation	**6,592**	**6,572**	**6,593**	**6,629**	**6,681**	**6,682**	**6,641**	**6,644**	**6,663**	**6,677**
Planning Reserves (13%)	880	877	880	885	892	892	886	887	889	891
East Reserves	**880**	**877**	**880**	**885**	**892**	**892**	**886**	**887**	**889**	**891**
East Obligation + Reserves	**7,471**	**7,450**	**7,474**	**7,514**	**7,573**	**7,574**	**7,528**	**7,531**	**7,552**	**7,568**
East Position	**14**	**(34)**	**24**	**36**	**158**	**146**	**125**	**121**	**(40)**	**58**
East Reserve Margin	14%	13%	14%	14%	16%	16%	15%	15%	13%	14%
West										
Thermal	2,048	2,048	2,048	2,048	1,736	1,736	1,736	1,736	1,598	1,265
Hydroelectric	570	570	570	570	570	570	570	570	570	570
Renewable	383	379	287	289	289	298	302	300	273	240
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	390	292	285	278	278	279	278	246	243	231
Demand Response	3	0	0	0	0	0	0	0	0	0
Sales	(165)	(161)	(110)	(110)	(80)	(80)	(80)	(80)	(80)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(272)	139	136	133	391	387	320	291	(308)	(365)
West Existing Resources	**2,955**	**3,265**	**3,214**	**3,206**	**3,182**	**3,189**	**3,126**	**3,062**	**2,296**	**1,861**
Front Office Transactions	741	508	518	513	135	130	197	272	1,107	1,107
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Wind+Storage	0	0	0	0	0	0	0	0	0	7
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	0	0	253	288	305	297	221	132
Demand Response	0	0	0	0	0	0	0	0	0	9
Other	0	0	0	0	0	0	0	0	169	578
West Planned Resources	**741**	**508**	**518**	**513**	**388**	**419**	**502**	**569**	**1,497**	**1,833**
West Total Resources	**3,696**	**3,772**	**3,732**	**3,719**	**3,571**	**3,608**	**3,627**	**3,631**	**3,793**	**3,695**
Load	3,387	3,441	3,486	3,513	3,529	3,570	3,597	3,626	3,657	3,684
Private Generation	(21)	(26)	(29)	(32)	(45)	(39)	(44)	(51)	(58)	(66)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
New Resources:										
Energy Efficiency	(52)	(76)	(102)	(127)	(153)	(178)	(202)	(225)	(247)	(266)
West obligation	**3,285**	**3,310**	**3,325**	**3,324**	**3,301**	**3,323**	**3,321**	**3,321**	**3,323**	**3,321**
Planning Reserves (13%)	427	430	432	432	429	432	432	432	432	432
West Reserves	**427**	**430**	**432**	**432**	**429**	**432**	**432**	**432**	**432**	**432**
West Obligation + Reserves	**3,712**	**3,740**	**3,757**	**3,756**	**3,730**	**3,755**	**3,753**	**3,753**	**3,755**	**3,753**
West Position	**(15)**	**32**	**(25)**	**(37)**	**(159)**	**(147)**	**(126)**	**(122)**	**39**	**(59)**
West Reserve Margin	13%	14%	12%	12%	8%	9%	9%	9%	14%	11%
System										
Total Resources	11,182	11,189	11,229	11,269	11,302	11,327	11,279	11,283	11,305	11,320
Obligation	9,876	9,882	9,918	9,953	9,982	10,005	9,962	9,966	9,985	9,998
Reserves	1,307	1,308	1,312	1,317	1,321	1,324	1,318	1,319	1,321	1,323
Obligation + Reserves	11,183	11,190	11,231	11,270	11,303	11,328	11,281	11,284	11,306	11,321
System Position	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 8.20 – Preferred Portfolio Summer Capacity Load and Resource Balance (2030-2038)

Calendar Year	2030	2031	2032	2033	2034	2035	2036	2037	2038
East									
Thermal	4,242	4,169	4,169	3,838	3,838	3,838	3,838	2,984	2,984
Hydroelectric	74	74	74	74	74	74	74	74	74
Renewable	723	706	675	725	726	724	737	740	697
Purchases	115	115	115	115	115	115	115	115	115
Qualifying Facilities	595	599	587	555	536	536	503	125	120
Demand Response	323	323	323	323	323	323	323	323	323
Sales	0	0	0	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	198	354	440	653	413	667	887	887	364
East Existing Resources	**6,235**	**6,306**	**6,348**	**6,248**	**5,991**	**6,242**	**6,443**	**5,213**	**4,643**
Front Office Transactions	205	179	213	307	309	309	309	309	309
Gas	179	179	179	179	179	179	179	831	831
Wind	479	508	475	527	528	526	539	553	540
Wind+Storage	0	0	24	27	27	27	27	28	28
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	163	188	154	188	184	182	186	456	392
Demand Response	170	170	182	183	183	199	203	214	349
Other	1	29	29	29	29	28	28	28	366
East Planned Resources	**1,197**	**1,254**	**1,257**	**1,439**	**1,440**	**1,450**	**1,472**	**2,419**	**2,816**
East Total Resources	**7,431**	**7,559**	**7,605**	**7,688**	**7,430**	**7,692**	**7,915**	**7,632**	**7,459**
Load	7,760	7,830	7,923	8,007	7,935	8,019	8,104	8,196	8,280
Private Generation	(249)	(264)	(281)	(316)	(227)	(261)	(295)	(330)	(374)
Existing Resources:									
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
New Resources:									
Energy Efficiency	(583)	(623)	(662)	(698)	(725)	(750)	(769)	(785)	(802)
East obligation	**6,700**	**6,713**	**6,751**	**6,763**	**6,754**	**6,780**	**6,811**	**6,853**	**6,876**
Planning Reserves (13%)	894	896	901	902	901	904	909	914	917
East Reserves	**894**	**896**	**901**	**902**	**901**	**904**	**909**	**914**	**917**
East Obligation + Reserves	**7,594**	**7,609**	**7,652**	**7,665**	**7,655**	**7,684**	**7,720**	**7,767**	**7,793**
East Position	**(162)**	**(50)**	**(46)**	**22**	**(225)**	**8**	**195**	**(134)**	**(334)**
East Reserve Margin	11%	13%	13%	14%	10%	13%	16%	11%	8%
West									
Thermal	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,053	411
Hydroelectric	570	570	570	570	570	570	570	570	570
Renewable	249	259	248	266	266	265	270	275	270
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	228	229	222	223	223	223	217	201	201
Demand Response	0	0	0	0	0	0	0	0	0
Sales	(78)	(78)	(78)	(78)	(78)	(78)	(24)	(24)	(24)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(199)	(354)	(441)	(653)	(414)	(668)	(888)	(888)	(365)
West Existing Resources	**2,034**	**1,889**	**1,785**	**1,592**	**1,831**	**1,576**	**1,409**	**1,185**	**1,062**
Front Office Transactions	1,107	1,107	1,107	1,107	1,107	1,107	1,006	1,107	1,107
Gas	0	0	0	0	0	0	0	208	208
Wind	0	0	0	0	0	0	0	0	0
Wind+Storage	8	8	8	9	9	9	9	19	18
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	171	198	162	259	254	251	308	488	531
Demand Response	9	9	9	9	9	9	9	57	89
Other	578	578	690	690	690	690	690	690	916
West Planned Resources	**1,873**	**1,900**	**1,977**	**2,075**	**2,070**	**2,066**	**2,022**	**2,569**	**2,869**
West Total Resources	**3,907**	**3,790**	**3,762**	**3,666**	**3,901**	**3,642**	**3,431**	**3,754**	**3,931**
Load	3,709	3,745	3,773	3,803	3,788	3,814	3,842	3,881	3,912
Private Generation	(79)	(102)	(134)	(173)	(155)	(191)	(226)	(260)	(300)
Existing Resources:									
Interruptible	0	0	0	0	0	0	0	0	0
Energy Efficiency	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
New Resources:									
Energy Efficiency	(285)	(303)	(320)	(335)	(349)	(363)	(376)	(387)	(399)
West obligation	**3,314**	**3,310**	**3,289**	**3,265**	**3,254**	**3,231**	**3,210**	**3,204**	**3,184**
Planning Reserves (13%)	431	430	428	424	423	420	417	417	414
West Reserves	**431**	**430**	**428**	**424**	**423**	**420**	**417**	**417**	**414**
West Obligation + Reserves	**3,745**	**3,740**	**3,717**	**3,689**	**3,677**	**3,651**	**3,627**	**3,621**	**3,598**
West Position	**161**	**49**	**46**	**(23)**	**224**	**(8)**	**(196)**	**133**	**333**
West Reserve Margin	18%	14%	14%	12%	20%	13%	7%	17%	23%
System									
Total Resources	11,338	11,349	11,368	11,354	11,331	11,334	11,346	11,386	11,390
Obligation	10,014	10,024	10,040	10,028	10,008	10,011	10,021	10,057	10,060
Reserves	1,325	1,326	1,328	1,327	1,324	1,324	1,326	1,330	1,331
Obligation + Reserves	11,339	11,350	11,368	11,355	11,332	11,335	11,347	11,387	11,391
System Position	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 8.21 – Preferred Portfolio Winter Capacity Load and Resource Balance (2020-2029)

Calendar Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
East										
Thermal	6,020	5,692	5,692	5,692	5,692	5,692	5,275	5,199	4,545	4,545
Hydroelectric	54	54	54	54	54	54	54	54	54	54
Renewable	992	1,536	1,594	1,579	1,020	1,020	1,010	1,009	1,010	1,001
Purchases	727	228	228	228	115	115	115	115	115	115
Qualifying Facilities	672	460	465	413	335	333	334	334	333	326
Demand Response	0	0	0	0	0	0	0	0	0	0
Sales	(173)	(173)	(173)	(173)	(148)	(148)	(66)	(52)	0	(77)
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	(159)	(154)	(151)	(146)	(400)	(394)	(391)	(390)	(440)	(325)
East Existing Resources	**8,100**	**7,608**	**7,675**	**7,611**	**6,632**	**6,637**	**6,295**	**6,235**	**5,582**	**5,606**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	180	180	180	180
Wind	0	0	0	24	681	681	684	684	684	678
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	39	35	61	61	64	64	64	68
Demand Response	0	0	0	0	0	0	0	0	0	0
Other	1	1	1	1	1	1	1	1	1	1
East Planned Resources	**1**	**1**	**40**	**60**	**743**	**743**	**929**	**929**	**929**	**927**
East Total Resources	**8,101**	**7,609**	**7,715**	**7,671**	**7,375**	**7,379**	**7,224**	**7,164**	**6,511**	**6,532**
Load	5,629	5,680	5,743	5,807	5,855	5,921	5,847	5,889	5,939	5,993
Private Generation	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(5)	(5)
Existing Resources:										
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:										
Energy Efficiency	(79)	(119)	(161)	(205)	(249)	(293)	(337)	(381)	(424)	(463)
East obligation	**5,344**	**5,355**	**5,376**	**5,396**	**5,399**	**5,420**	**5,301**	**5,298**	**5,305**	**5,319**
Planning Reserves (13%)	718	719	722	724	725	728	712	712	713	714
East Reserves	**718**	**719**	**722**	**724**	**725**	**728**	**712**	**712**	**713**	**714**
East Obligation + Reserves	**6,062**	**6,074**	**6,098**	**6,120**	**6,123**	**6,148**	**6,014**	**6,010**	**6,018**	**6,033**
East Position	**2,039**	**1,535**	**1,617**	**1,551**	**1,252**	**1,232**	**1,211**	**1,154**	**493**	**499**
East Reserve Margin	52%	42%	44%	42%	37%	36%	36%	35%	23%	23%
West										
Thermal	2,040	2,040	2,040	2,040	1,728	1,728	1,728	1,728	1,590	1,258
Hydroelectric	670	670	670	670	670	670	670	670	670	670
Renewable	672	351	232	230	137	137	138	138	137	136
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	142	102	93	88	75	75	72	45	45	33
Demand Response	0	0	0	0	0	0	0	0	0	0
Sales	(154)	(154)	(113)	(113)	(81)	(81)	(81)	(81)	(81)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	157	153	149	146	399	393	390	389	439	324
West Existing Resources	**3,526**	**3,161**	**3,071**	**3,059**	**2,926**	**2,920**	**2,915**	**2,888**	**2,799**	**2,342**
Front Office Transactions	135	277	312	323	46	52	54	103	239	256
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Wind+Storage	0	0	0	0	0	0	0	0	0	4
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	0	0	59	59	62	62	62	87
Demand Response	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	180	615
West Planned Resources	**135**	**277**	**312**	**323**	**104**	**111**	**116**	**164**	**481**	**962**
West Total Resources	**3,661**	**3,438**	**3,383**	**3,382**	**3,030**	**3,031**	**3,031**	**3,052**	**3,279**	**3,303**
Load	3,416	3,458	3,499	3,529	3,550	3,576	3,605	3,640	3,672	3,706
Private Generation	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:										
Energy Efficiency	(61)	(90)	(121)	(153)	(185)	(216)	(246)	(275)	(303)	(328)
West obligation	**3,327**	**3,340**	**3,350**	**3,347**	**3,335**	**3,331**	**3,329**	**3,335**	**3,340**	**3,347**
Planning Reserves (13%)	432	434	435	435	434	433	433	434	434	435
West Reserves	**432**	**434**	**435**	**435**	**434**	**433**	**433**	**434**	**434**	**435**
West Obligation + Reserves	**3,759**	**3,774**	**3,785**	**3,782**	**3,769**	**3,764**	**3,762**	**3,769**	**3,774**	**3,783**
West Position	**(98)**	**(337)**	**(402)**	**(400)**	**(739)**	**(733)**	**(732)**	**(717)**	**(494)**	**(479)**
West Reserve Margin	10%	3%	1%	1%	(9%)	(9%)	(9%)	(8%)	(2%)	(1%)
System										
Total Resources	11,762	11,047	11,098	11,053	10,406	10,411	10,255	10,216	9,791	9,836
Obligation	8,671	8,695	8,725	8,743	8,734	8,751	8,631	8,634	8,645	8,666
Reserves	1,150	1,153	1,157	1,160	1,158	1,161	1,145	1,145	1,147	1,150
Obligation + Reserves	9,821	9,848	9,883	9,902	9,892	9,912	9,776	9,779	9,792	9,815
System Position	1,941	1,198	1,215	1,151	513	499	479	437	(1)	20
Reserve Margin	36%	27%	27%	26%	19%	19%	19%	18%	13%	13%

Table 8.22 – Preferred Portfolio Winter Capacity Load and Resource Balance (2030-2038)

Calendar Year	2030	2031	2032	2033	2034	2035	2036	2037	2038
East									
Thermal	4,311	4,239	4,239	3,908	3,908	3,908	3,908	3,054	3,054
Hydroelectric	54	54	54	54	54	54	54	54	54
Renewable	942	891	846	1,015	1,036	1,039	1,045	1,099	1,073
Purchases	115	115	115	115	115	115	115	115	115
Qualifying Facilities	325	326	310	284	251	251	222	26	26
Demand Response	0	0	0	0	0	0	0	0	0
Sales	(77)	0	0	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	(395)	(490)	(451)	(306)	(150)	(307)	(359)	82	(278)
East Existing Resources	**5,241**	**5,100**	**5,078**	**5,035**	**5,180**	**5,026**	**4,950**	**4,395**	**4,009**
Front Office Transactions	0	0	0	0	0	0	0	0	0
Gas	180	180	180	180	180	180	180	881	881
Wind	947	953	898	1,105	1,131	1,135	1,142	1,213	1,219
Wind+Storage	0	0	28	35	35	36	36	38	38
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	79	79	67	108	112	113	111	254	228
Demand Response	0	0	0	0	0	0	0	0	0
Other	1	31	31	31	31	30	30	30	390
East Planned Resources	**1,207**	**1,243**	**1,204**	**1,459**	**1,490**	**1,493**	**1,498**	**2,416**	**2,756**
East Total Resources	**6,449**	**6,343**	**6,282**	**6,494**	**6,670**	**6,519**	**6,449**	**6,811**	**6,765**
Load	6,023	6,074	6,113	6,180	6,232	6,287	6,320	6,380	6,431
Private Generation	(6)	(7)	(8)	(9)	(10)	(12)	(14)	(15)	(17)
Existing Resources:									
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:									
Energy Efficiency	(502)	(537)	(572)	(604)	(628)	(650)	(668)	(683)	(698)
East obligation	**5,310**	**5,324**	**5,328**	**5,362**	**5,389**	**5,420**	**5,434**	**5,477**	**5,510**
Planning Reserves (13%)	713	715	716	720	724	728	729	735	739
East Reserves	**713**	**715**	**716**	**720**	**724**	**728**	**729**	**735**	**739**
East Obligation + Reserves	**6,023**	**6,040**	**6,044**	**6,083**	**6,113**	**6,147**	**6,163**	**6,212**	**6,249**
East Position	**425**	**303**	**238**	**412**	**558**	**372**	**286**	**599**	**516**
East Reserve Margin	21%	19%	18%	21%	24%	20%	19%	24%	23%
West									
Thermal	1,258	1,258	1,258	1,258	1,258	1,258	1,258	1,034	392
Hydroelectric	670	670	670	670	670	670	670	670	670
Renewable	135	135	128	155	159	159	160	169	170
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	33	33	27	29	29	29	25	24	24
Demand Response	0	0	0	0	0	0	0	0	0
Sales	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	394	488	450	305	148	305	358	(83)	277
West Existing Resources	**2,410**	**2,505**	**2,453**	**2,337**	**2,184**	**2,341**	**2,392**	**1,735**	**1,454**
Front Office Transactions	255	284	302	197	216	257	279	353	457
Gas	0	0	0	0	0	0	0	215	215
Wind	0	0	0	0	0	0	0	0	0
Wind+Storage	4	4	4	5	5	5	5	11	11
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	69	68	58	120	125	126	145	209	247
Demand Response	0	0	0	0	0	0	0	0	0
Other	615	615	735	735	735	735	735	735	975
West Planned Resources	**943**	**971**	**1,098**	**1,058**	**1,081**	**1,123**	**1,164**	**1,524**	**1,906**
West Total Resources	**3,353**	**3,476**	**3,551**	**3,395**	**3,264**	**3,464**	**3,555**	**3,259**	**3,360**
Load	3,727	3,751	3,782	3,816	3,849	3,880	3,902	3,933	3,967
Private Generation	(2)	(3)	(3)	(4)	(4)	(5)	(7)	(8)	(11)
Existing Resources:									
Interruptible	0	0	0	0	0	0	0	0	0
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:									
Energy Efficiency	(352)	(374)	(396)	(415)	(433)	(450)	(467)	(482)	(497)
West obligation	**3,345**	**3,346**	**3,355**	**3,369**	**3,384**	**3,396**	**3,400**	**3,415**	**3,431**
Planning Reserves (13%)	435	435	436	438	440	441	442	444	446
West Reserves	**435**	**435**	**436**	**438**	**440**	**441**	**442**	**444**	**446**
West Obligation + Reserves	**3,780**	**3,781**	**3,791**	**3,808**	**3,824**	**3,838**	**3,842**	**3,859**	**3,877**
West Position	**(426)**	**(305)**	**(239)**	**(413)**	**(559)**	**(373)**	**(287)**	**(600)**	**(517)**
West Reserve Margin	0%	4%	6%	1%	(4%)	2%	5%	(5%)	(2%)
System									
Total Resources	9,802	9,819	9,834	9,889	9,935	9,984	10,004	10,070	10,125
Obligation	8,655	8,670	8,683	8,732	8,773	8,816	8,834	8,892	8,941
Reserves	1,148	1,150	1,152	1,158	1,163	1,169	1,171	1,179	1,185
Obligation + Reserves	9,803	9,820	9,835	9,890	9,936	9,985	10,005	10,071	10,126
System Position	(1)	(2)	(1)	(1)	(2)	(1)	(1)	(1)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%

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, a number of additional sensitivity cases were 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 8.23 lists additional sensitivity studies performed for the 2019 IRP. To isolate the impact of a given planning assumption, all sensitivity cases are compared to the preferred portfolio, case P-45CNW.

Table 8.23 – Summary of Additional Sensitivity Cases

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Customer Preference Target	First Year of New Thermal
S-01	Low Load	P-45CNW	20,617	Low	Base	Base	Base	Base	2030
S-02	High Load	P-45CNW	22,602	High	Base	Base	Base	Base	2026
S-03	1 in 20 Load Growth	P-45CNW	21,634	1 in 20	Base	Base	Base	Base	2026
S-04	Low Private Generation	P-45CNW	21,758	Base	Low	Base	Base	Base	2029
S-05	High Private Generation	P-45CNW	21,371	Base	High	Base	Base	Base	2030
S-06	Business Plan	P-45CNW	21,695	Base	Base	Base	Base	Base	2028
S-07	No Customer Preference	P-45CNW	21,609	Base	Base	Base	Base	None	2030
S-08	All Customer Preference	P-45CNW	21,636	Base	Base	Base	Base	High	2030

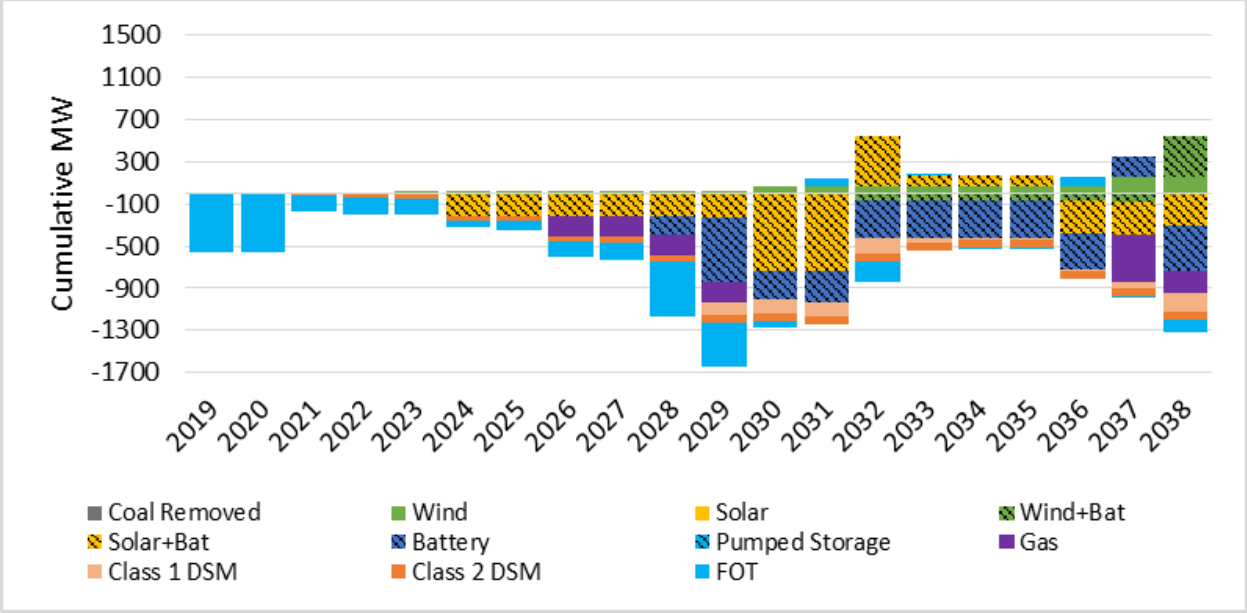
Low Load Growth Sensitivity (S-01)

Table 8.24 shows the PVRR impacts of the S-01 sensitivity relative to P-45CNW. The reduced loads lower system costs significantly over the 20-year study period. Figure 8.46 summarizes portfolio impacts. FOTs are reduced by an average of 275 MW from 2019 to 2024, and by an average of 129 MW from 2025 to 2027, followed thereafter by an average of 103 MW less per year. Over the full portfolio, cumulative wind is higher by 162 MW, offset by a decrease of 346 MW of wind with battery, solar with battery and standalone battery. Renewable and storage resources are reduced by 184 MW by the end of the study period, gas peakers are 221 MW less and DSM decreases by 251 MW.

Table 8.24 – Stochastic Mean PVRR (Benefit)/Cost of S-01 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-01**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$22,080	($1,127)

Figure 8.46 – Increase/(Decrease) in Nameplate Capacity of S-01 Relative to Case P-45CNW



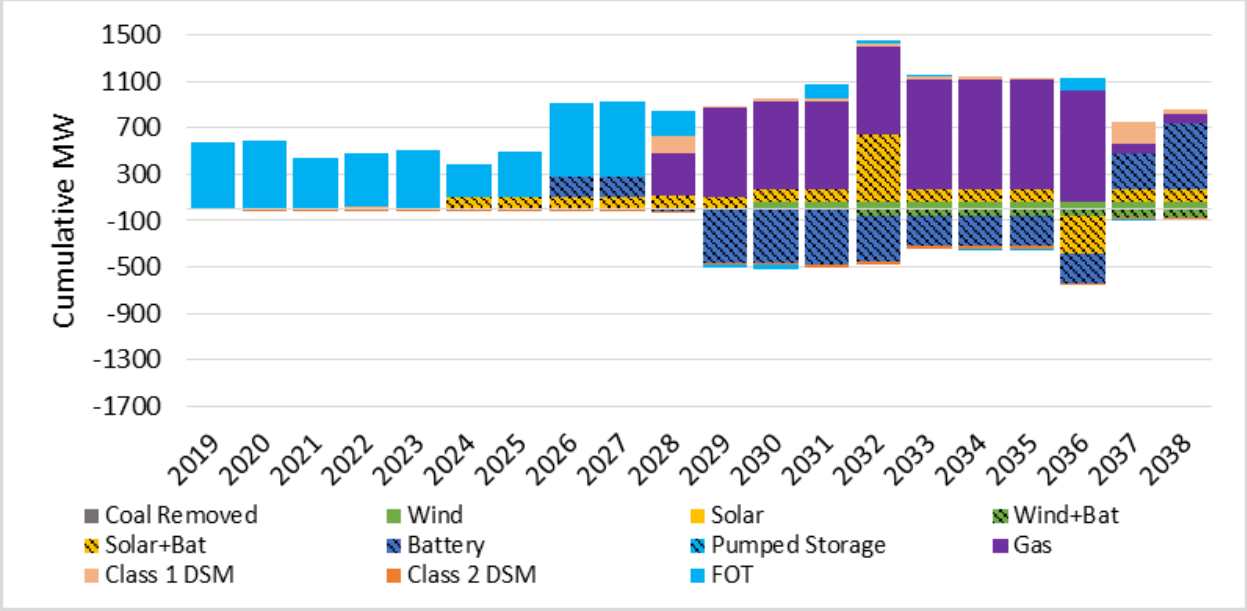
High Load Growth Sensitivity (S-02)

Table 8.25 shows the PVRR impacts of the S-02 sensitivity relative to P-45CNW. Higher loads result in significantly increased resource requirements which translate into higher system costs. Figure 8.47 summarizes the resource portfolio impacts. Annual FOTs increase by an average of 472 MW through 2024 and 556 MW from 2025 to 2027, followed by 35 MW thereafter. Renewable and storage resources increase by 670 MW by the end of the study period. An additional 953 MW of natural gas peaking capacity is shifted earlier, split between 2028, 2029 and 2033 instead of 370 MW of gas peaker and 505 MW of Gas CCCT in 2037, for a net increase of 78 MW. DSM increases by 23 MW by the end of the study period.

Table 8.25 – Stochastic Mean PVRR (Benefit)/Cost of S-02 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-02**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$24,346	$1,139

Figure 8.47 – Increase/(Decrease) in Nameplate Capacity of S-02 Relative to Case P-45CNW



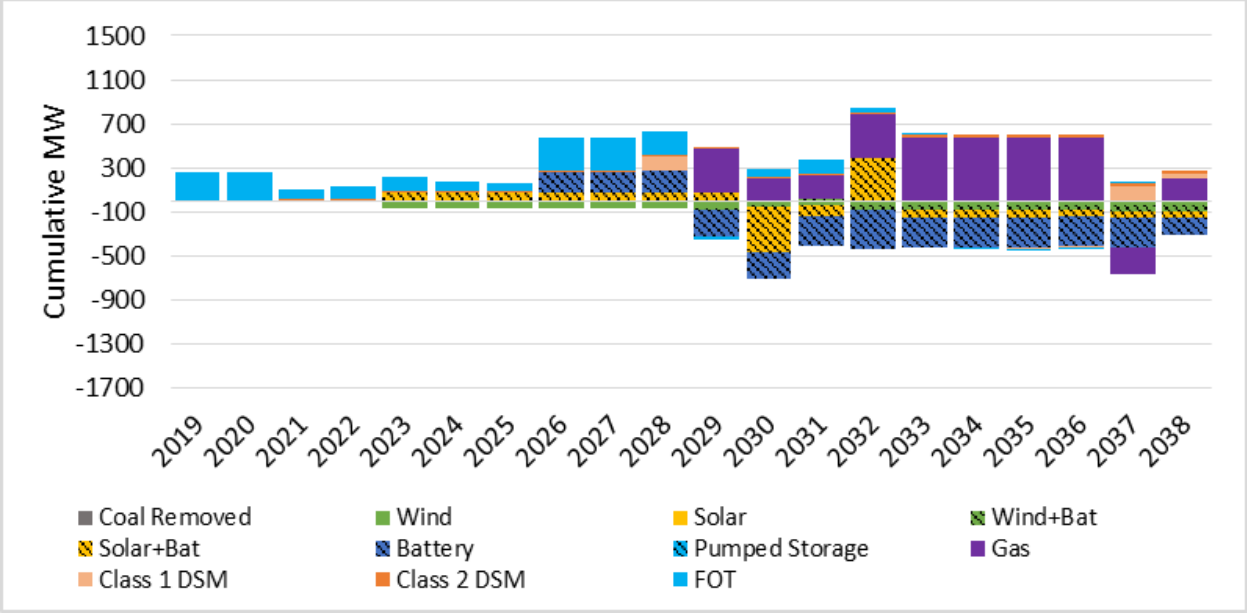
1-in-20 Load Growth Sensitivity (S-03)

Table 8.26 shows the PVRR impacts of the S-03 sensitivity relative to P-45CNW. This sensitivity assumes 1-in-20 extreme weather conditions during the summer (July) for each state. System costs are higher due to requirements to meet additional peak load. Figure 8.48 summarizes resource portfolio impacts. Higher peak loads require more annual FOTs, 158 MW greater on average from 2019-2024, 220 MW more 2025-2027 and 36 MW thereafter. Renewables and storage are decreased by 304 MW, offset by an increase of 210 MW in gas peakers and a 62 MW increase in DSM by the end of the study period.

Table 8.26 – Stochastic Mean PVRR (Benefit)/Cost of S-03 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-03**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$23,388	$181

Figure 8.48 – Increase/(Decrease) in Nameplate Capacity of S-03 Relative to Case P-45CNW



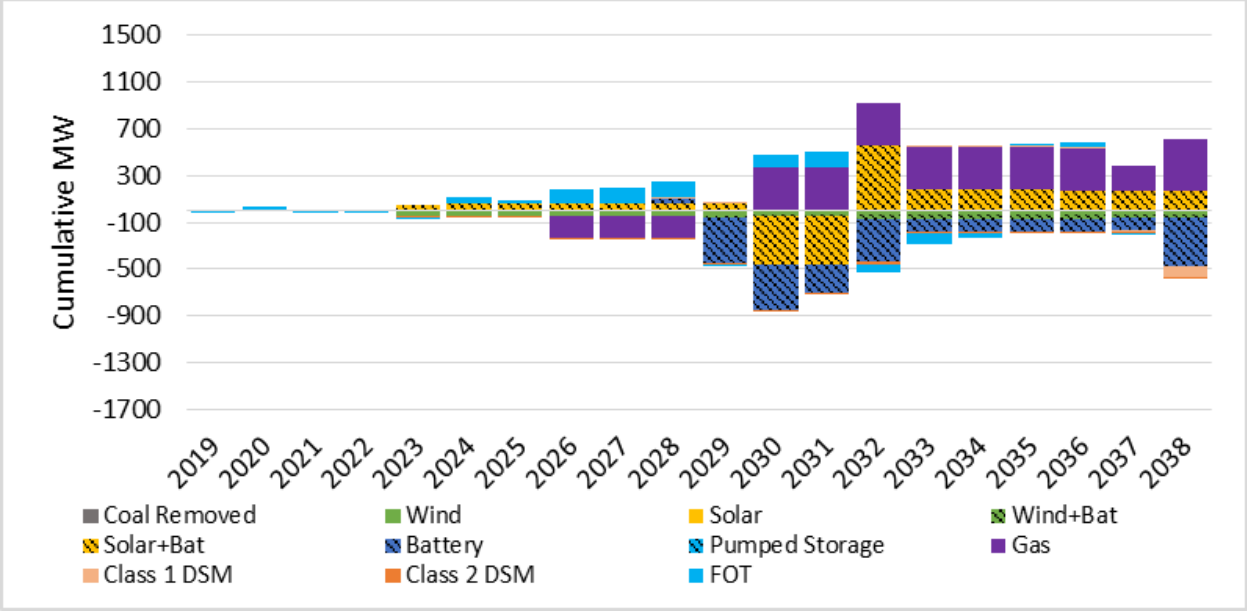
Low Private Generation Sensitivity (S-04)

Table 8.27 shows the PVRR impacts of the S-04 sensitivity relative to P-45CNW. The lower private generation assumption result in higher net loads, increasing system costs. Figure 8.49 summarizes portfolio impacts. Annual average FOTs increase by 6 MW from 2019-2024 and then 98 MW from 2025-2027, leveling out to 17 MW higher on average thereafter. Renewables and storage decrease by 305 MW over the long-term, along with 114 MW less DSM, which are offset by an increase of 443 MW in gas peakers.

Table 8.27 – Stochastic Mean PVRR (Benefit)/Cost of S-04 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-04**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$23,308	$101

Figure 8.49 – Increase/(Decrease) in Nameplate Capacity of S-04 Relative to Case P-45CNW



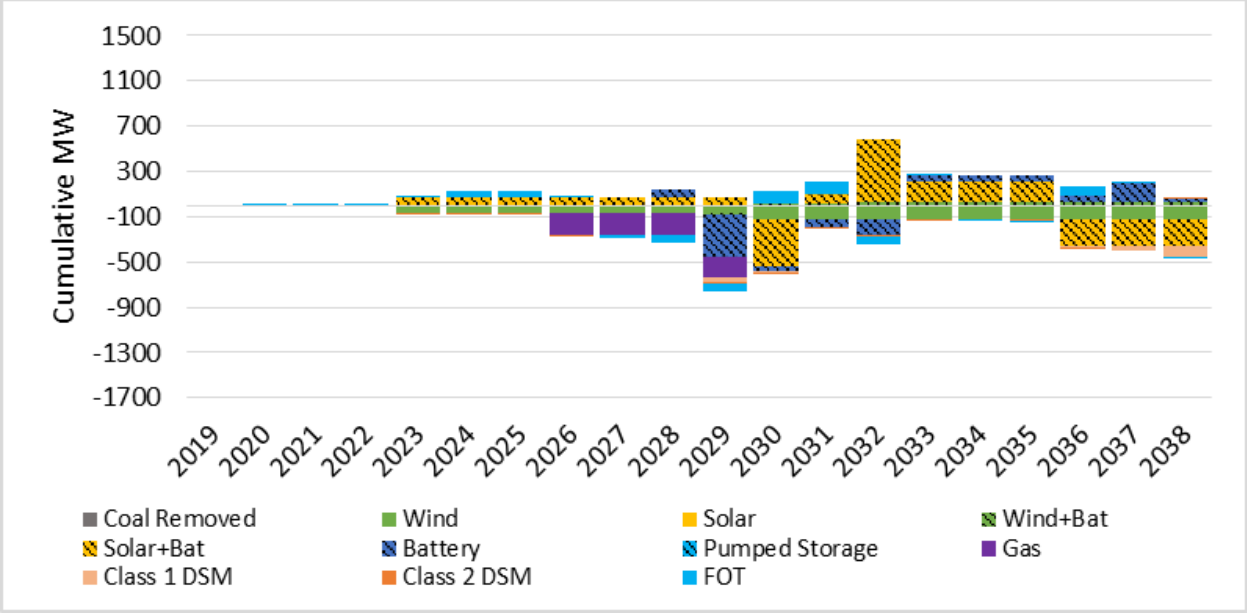
High Private Generation Sensitivity (S-05)

Table 8.28 shows the PVRR impacts of the S-05 sensitivity relative to P-45CNW. The higher private generation assumptions decrease net load, which in turn decreases system costs. Figure 8.50 summarizes portfolio impacts, which are minor for FOTs and natural gas over the long-term. There is 300 MW less renewable capacity and 92 MW less DSM.

Table 8.28 – Stochastic Mean PVRR (Benefit)/Cost of S-05 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-05**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$22,970	($238)

Figure 8.50 – Increase/(Decrease) in Nameplate Capacity of S-05 Relative to Case P-45CNW



Business Plan Sensitivity (S-06)

Table 8.29 shows the PVRR impacts of the S-06 sensitivity relative to P-45CNW. System costs increase by $72m when studied in SO and $831m when analyzed using PaR. This sensitivity complies with Utah requirements to perform a business plan sensitivity consistent with the Public Service Commission of Utah's order in Docket No. 15-035-04, summarized as follows:

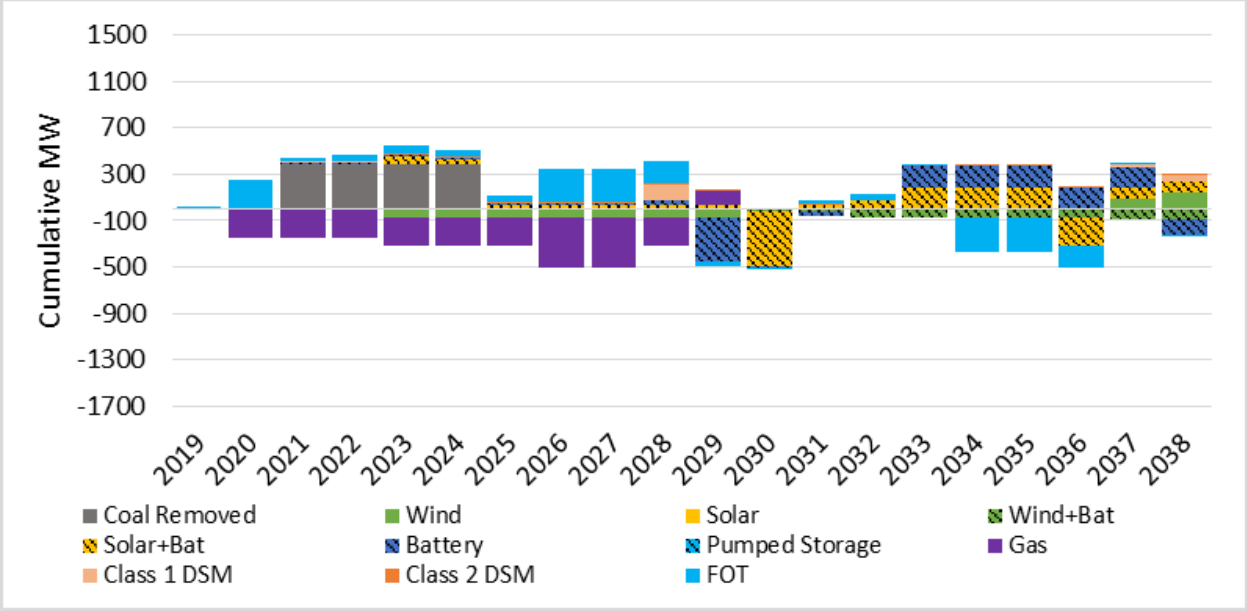
- Over the first three years, resources align with those assumed in PacifiCorp's December 2018 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Figure 8.51 summarizes resource portfolio impacts, showing differences associated with the preferred portfolio's assumptions of Naughton Unit 3's gas conversion and Cholla Unit 4's 2020 retirement. These are coupled with an average annual increase of 77 MW FOTs 2019-2024, 207 MW higher average annual FOTs 2025-2027 and then 51 MW less FOTs thereafter. There is a difference in the timing of new renewable resources and storage, which net 23 MW higher through the longer term. DSM increases by 57 MW.

Table 8.29 – Stochastic Mean PVRR (Benefit)/Cost of S-06 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-06**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$24,038	$831

Figure 8.51 – Increase/(Decrease) in Nameplate Capacity of S-06 Relative to Case P-45CNW



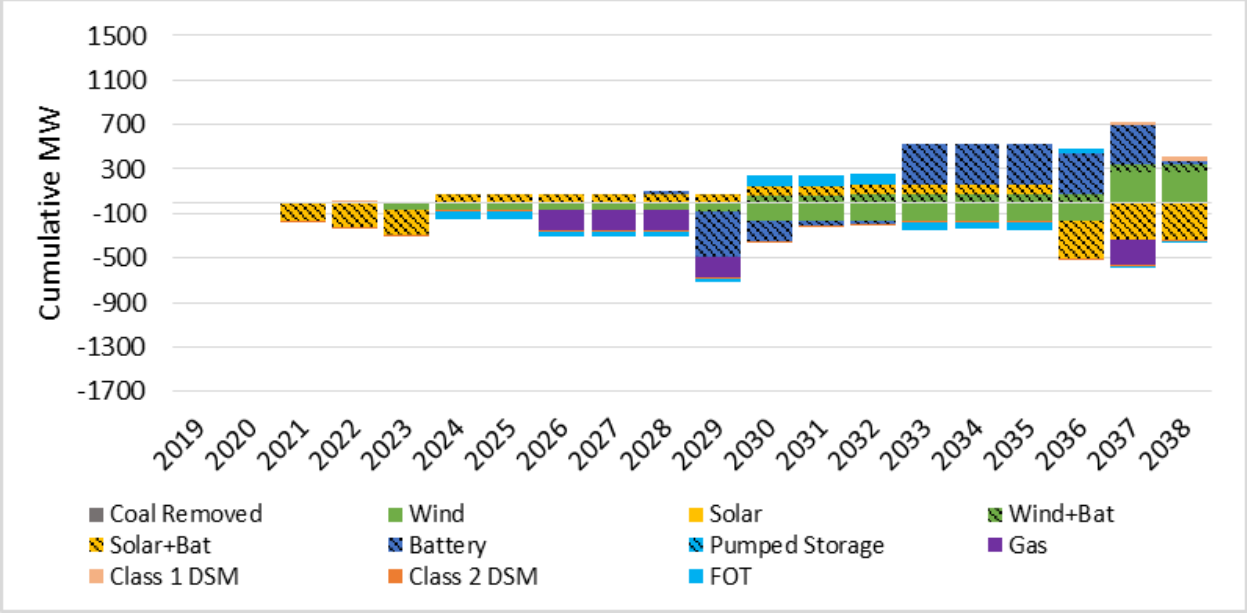
No Customer Preference Sensitivity (S-07)

Table 8.30 shows the PVRR impacts of the S-07 sensitivity relative to P-45CNW. The no customer preference sensitivity reflects no renewable resources specifically assigned to customer preference, compared to base renewable resource proxy options. Figure 8.52 summarizes portfolio impacts, which are zero for FOTs until 2024, when FOTs are 77 MW less, followed by an annual FOT average decrease of 55 MW 2025-2027 and an average annual increase of 3 MW thereafter. There is a 30 MW increase in renewable and storage capacity and 32 MW more DSM. Gas peaking resources are postponed and net to zero.

Table 8.30 – Stochastic Mean PVRR (Benefit)/Cost of S-07 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-07**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$23,126	($81)

Figure 8.52 – Increase/(Decrease) in Nameplate Capacity of S-07 Relative to Case P-45CNW



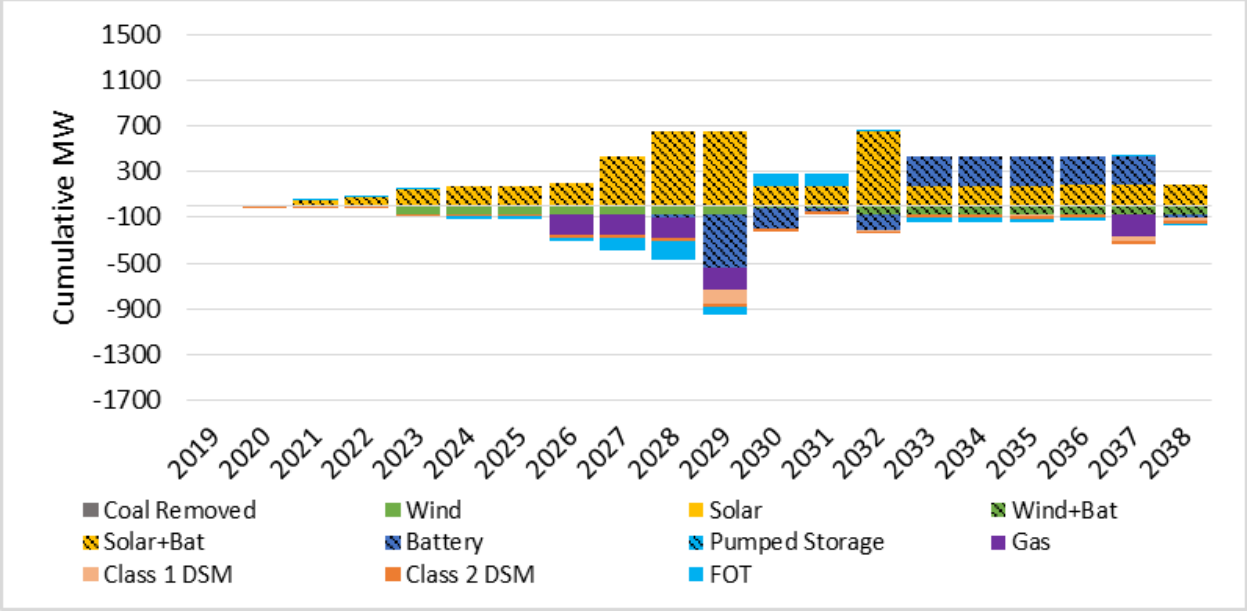
High Customer Preference Sensitivity (S-08)

Table 8.31 shows the PVRR impacts of the S-08 sensitivity relative to P-45CNW. The high customer preference sensitivity reflects a wider range of renewable resources assigned to customer preference, compared to base renewable resource proxy options. Figure 8.53 summarizes portfolio impacts, which are zero for natural gas over the long term, delaying peakers. The annual average FOTs are zero until a 2024 decrease of 20 MW followed by 51 MW less on average 2025-2027, and 12 MW less on average thereafter. Renewable resources and storage increase by 80 MW, slightly offset by a decrease of 62 MW DSM.

Table 8.31 – PVRR (Benefit)/Cost of S-08 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-08**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$23,186	($22)

Figure 8.53 – Increase/(Decrease) in Nameplate Capacity of S-08 Relative to Case P-45CNW



CHAPTER 9 – ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2019 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 2019 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases (front office transactions or FOTs), and the purchase and sale of renewable energy credits (RECs).
- The 2019 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, distributed generation, carbon dioxide (CO_2) emission polices, Regional Haze outcomes, and availability of purchases from the market.
- 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 2019 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.

Resources included in the 2019 IRP preferred portfolio help define the actions included in the action plan, focusing on the size, timing, type, and amount of resources needed to meet load obligations, and current and potential future state regulatory requirements.

The 2019 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 planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2019 IRP, such as capital and operating costs, are based upon recent cost-and-performance data. However, it is important to recognize that the resources identified in the plan are 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 commission orders.

In addition to presenting the 2019 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2019 IRP acquisition path analysis, Chapter 9 covers 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 2019 IRP Action Plan

The 2019 IRP action plan identifies specific actions PacifiCorp will take over the next two to four years to deliver its preferred portfolio. Action items are based on the 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 2019 IRP public-input process. Table 9.1 details specific 2019 IRP action items by resource category.

Table 9.1 – 2019 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Naughton Unit 3:** • PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory notices and filings, in 2020. Initiate procurement of materials in Q4 2019. Conversion completed in 2020.
1b	**Cholla Unit 4:** • PacifiCorp will initiate the process of retiring Cholla Unit 4, including all required regulatory notices and filings, as soon as practicable, but will remove Cholla Unit 4 from service no later than January 2023 and earlier if possible. • PacifiCorp will continue to coordinate with the plant operator to transition employees, develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans and confirm joint-ownership obligations; complete required regulatory notices and filings; administer termination, amendment, or close-out of existing permits, contracts and other agreements; and coordinate with state and local stakeholders as appropriate. • By the end of Q1 2020, the plant operator will be requested to develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans, and confirm joint-ownership obligations. • By the end of Q2 2020, the plant operator will be requested to file required transmission interconnection and transmission services unit retirement notices/request for study. • By the end of Q4 2020, PacifiCorp will finalize an employee transition agreement with the plant operator.
1c	**Jim Bridger Unit 1:** • PacifiCorp will initiate the process of retiring Jim Bridger Unit 1 by the end of December 2023, including completion of all required regulatory notices and filings. By the end of Q2 2020, file a request with PacifiCorp transmission to study the year-end 2023 retirement of Jim Bridger Unit 1. By the end of Q2 2021, confirm transmission system reliability assessment and year-end 2023 retirement economics in 2021 IRP filing. • By the end of Q2 2021, finalize an employee transition plan. • By the end of Q2 2021, develop a community action plan in coordination with community leaders. • By the end of Q4 2021, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Jim Bridger Unit 1.

	• By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
1d	**<u>Naughton Units 1-2:</u>** • PacifiCorp will initiate the process of retiring Naughton Units 1-2 by the end of December 2025, including completion of all required regulatory notices and filings. By the end of Q2 2022, file a request with PacifiCorp transmission to study the year-end 2025 retirement of Naughton Units 1 and 2. • By the end of Q2 2022, finalize an employee transition plan. • By the end of Q2 2022, develop a community action plan in coordination with community leaders. • By the end of Q2 2023, confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, 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. • By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
1e	**<u>Craig Unit 1:</u>** • The plant operator will be requested to administer termination, amendment, or close-out of existing permits, contracts, and other agreements to support retiring Craig Unit 1, including completion of all required regulatory notices and filings, by the end of December 2025.
Action Item	**2. New Resource Actions**
2a	**<u>Customer Preference Request for Proposals:</u>** • PacifiCorp will work with customers to achieve their respective resource preference requirements. By the end of Q4 2019, sign a fifteen year 80 megawatt (MW) Power Purchase Agreement (PPA) for Utah solar for six Utah Schedule 34 customers. By the end of Q4 2019, sign two 20-year PPAs of approximately 80 MW for a large Utah Schedule 34 customer. Monitor the finalization of rules by the Public Service Commission of Utah for House Bill (HB) 411 (anticipated by the end of Q1 2020), that provides a path forward for development of a program for participating communities to begin procuring renewable resources.
2b	**<u>All Source Request for Proposals:</u>** • PacifiCorp will issue an all-source request for proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2023. • By the end of Q4 2019, file a request for interconnection queue reform with the Federal Energy Regulatory Commission (FERC) and make state filings to initiate the process of identifying an independent evaluator. • In Q1 2020, file a draft all-source RFP with the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, as applicable.

	• In Q2 2020, receive approval from FERC to reform the interconnection queue. • In Q2 2020, receive approval of the all-source RFP from applicable state regulatory commissions and issue the RFP to the market. • In Q3 2020, identify a preliminary final shortlist from the all-source RFP and initiate transmission interconnection studies consistent with queue reform as approved by FERC. • In Q2 2021, 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 2022 execute definitive agreements with winning bids from the all-source RFP. • By Q4 2023, winning bids from the all-source RFP achieve commercial operation.
Action Item	**3. Transmission Action Items**
3a	**<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.
3b	**<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.
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.
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. • Yakima Washington Reinforcements: 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 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.
3e	**Yakima Washington Reinforcements:** • 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 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 Hemmingway:** • 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.
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 support the projects by providing information and participating in public outreach.

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

Energy Efficiency Targets:

- PacifiCorp will acquire cost-effective Class 2 DSM (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 will be provided in Appendix D in Volume II of the 2019 IRP.

<table>
<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2019</td><td>562</td><td>126</td></tr>
<tr><td>2020</td><td>536</td><td>132</td></tr>
<tr><td>2021</td><td>538</td><td>133</td></tr>
<tr><td>2022</td><td>571</td><td>143</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.

- Energy Efficiency Bundling: PacifiCorp will continue to evaluate alternate bundling methodologies of Class 2 DSM in the 2019 IRP.
- Direct-Load Control: PacifiCorp will acquire cost-effective Class 1 DSM (i.e., demand response) in Utah targeting approximately 29 MW of incremental capacity from 2020 through 2023.

</td></tr>
<tr><th>Action Item</th><th>5. Front Office Transactions</th></tr>
<tr><td>5a</td><td>

Market Purchases:

- 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></tr>
<tr><th>Action Item</th><th>6. Renewable Energy Credit Actions</th></tr>
<tr><td>6a</td><td>

Renewable Portfolio Standards (RPS):

- 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 then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington RPS targets.

</td></tr>
<tr><td>6b</td><td>

Renewable Energy Credit Sales:

- Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

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

Progress on Previous Action Plan Items

This section describes progress that has been made on previous action plan items documented in the 2017 IRP and the 2017 IRP Update reports filed with the state commissions on April 4, 2017 and May 1, 2018, respectively. Many of these action items have been superseded in some form by items identified in the current IRP action plan. The status for all action items is summarized in Table 9.2.

Table 9.2 – 2017 IRP Action Plan Status Update

Action Item	Activity	Status
1a	**Wind Repowering** • PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016. – Continue to refine and update the economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed. – By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills). – Pursue regulatory review and approval as necessary. – By May 2018, issue the engineering, procurement, and construction (EPC) notice to proceed to begin implementing the wind repowering for specific projects consistent with updated financial analysis.	PacifiCorp has continued to refine and update its economic analysis of wind repowering, which has been provided in regulatory filings in California, Idaho, Oregon, Utah, and Wyoming. PacifiCorp completed technical and economic analysis of repowering Goodnoe Hills in 2018 and included this facility is in the scope of the wind repowering project described in regulatory filings. PacifiCorp completed technical and economic analysis of Foote Creek I in 2019, which demonstrated that repowering the facility provides economic benefits to customers. Regulatory approval of the wind repowering project was received from the Idaho Public Service Commission on December 28, 2017; the Public Service Commission of Wyoming on December 18, 2018, the Public Service Commission of Utah on May 29, 2018, and the Public Utility Commission of Oregon on September 16, 2019. Regulatory approval is pending in California. In June 2018, PacifiCorp issued notices to proceed to begin implementing certain wind repowering projects, consistent with the updated financial analysis. Except for Foote Creek I, PacifiCorp issued notices to proceed for the remainder of the wind repowering projects by the end of December 2018.

Action Item	Activity	Status
	– By December 31, 2020, complete installation of wind repowering equipment on all identified projects.	In July 2019, PacifiCorp acquired the Eugene Water & Electric Board's minority interest in the Foote Creek I wind project and cancelled the power purchase agreement with Bonneville Power Administration. PacifiCorp issued notices to proceed related to repowering efforts at Foote Creek I in late July 2019. The Public Service Commission of Wyoming issued a Certificate of Public Convenience and Necessity related to repowering the Foote Creek I facility on September 12, 2019. PacifiCorp is on track to complete installation of the wind repowering equipment on all of its existing projects by December 31, 2020.
1b	**<u>Wind Request for Proposals</u>** • PacifiCorp will issue a wind resource request for proposals (RFP) for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020. – April 2017, notify the Utah Public Service Commission of intent to issue the Wyoming wind resource RFP. – May-June, 2017, file a draft Wyoming wind RFP with the Utah Public Service Commission and the Washington Utilities and Transportation Commission. – May-June, 2017, file to open a Wyoming wind RFP docket with the Public Utility Commission of Oregon and initiate the Independent Evaluator RFP. – June-July, 2017, file a draft Wyoming wind RFP with the Public Utility Commission of Oregon and file a Public Convenience and	PacifiCorp completed all of the notice and draft filing requirements related to the RFP (the 2017R Request for Proposals (2017R RFP)). In accordance with the Utah and Oregon RFP proceedings, the 2017R RFP was issued on September 27, 2017. Bid results were received, evaluated and PacifiCorp established a final shortlist that included four wind projects in Wyoming totaling 1,311. PacifiCorp ultimately executed contracts to move forward with four projects totaling 1,150 MW. The 2017R RFP was monitored by two independent evaluators. On April 12, 2018, PacifiCorp received conditional CPCNs for the TB Flats I & II wind project, the Cedar Springs wind project, the Ekola Flats wind project, and associated network upgrades from the Wyoming Public Service Commission. These conditional CPCNs were required to secure the necessary rights-of-way. Final CPCNs to allow construction to initiate were issued by the Wyoming Public Service Commission on March 12, 2019 for TB Flats I &

Action Item	Activity	Status
	Necessity (CPCN) application with the Public Service Commission of Wyoming. – By August 2017, obtain approval of the Wyoming wind resource RFP from the Public Utility Commission of Oregon, the Utah Public Service Commission, and the Washington Utilities and Transportation Commission. – By August 2017, issue the Wyoming wind RFP to the market. – By October 2017, Wyoming wind RFP bids are due. – November-December, 2017, complete initial shortlist bid evaluation. – By January 2018, complete final shortlist bid evaluation, seek acknowledgement of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission. – By March 2018, receive CPCN approval from the Wyoming Public Service Commission. – Complete construction of new wind projects by December 31, 2020.	II, April 17, 2019 for Ekola Flats and network upgrades, and September 6, 2019 for Cedar Springs. All of the new wind projects resulting from the 2017R RFP are underway and on track to achieve commercial operation by the end of 2020.
1c	**<u>Renewable Portfolio Standard Compliance</u>** • PacifiCorp will issue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements. – As needed, issue RFPs seeking then-current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2020.	PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed for both California Oregon, and Washington. PacifiCorp will issue an RFP seeking unbundled RECs in the fourth quarter of 2019 to meet state RPS compliance requirements in California and Washington.

Action Item	Activity	Status
	– As needed, issue RFPs seeking low-cost then-current-year, forward-year, or older vintage unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets, deferring the currently projected 2035 initial shortfall after accounting for preferred portfolio renewable resources.	
1d	**<u>Renewable Energy Credit Optimization</u>** • Before filing the 2017 IRP Update, evaluate potential opportunities to re-allocate RECs from Utah, Wyoming, and Idaho to Oregon, Washington, or California. • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp issued reverse RFPs in June 2017, September 2017, My 2018, October 2018, and April 2019. 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.
Action Item	**2. Transmission Actions**	**Status**
2a	**<u>Aeolus to Bridger/Anticline</u>** • By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary – June-July 2017, file a CPCN application with the Public Service Commission of Wyoming. – By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way.	PacifiCorp filed a CPCN application with the Public Service Commission of Wyoming on June 30, 2017. On April 12, 2018, PacifiCorp received a conditional CPCN for the Aeolus-to-Bridger/Anticline transmission line from the Wyoming Public Service Commission. This CPCN was required to secure the necessary rights-of-way. The Wyoming Industrial Siting Counsel issued the siting permit on October 24, 2018. On April 9, 2019, the Public Service Commission of Wyoming issued the full CPCN. PacifiCorp issued full notice to proceed to the EPC contractors. Construction began on April 10, 2019

Action Item	Activity	Status
	– By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed. – By April 2019, issue EPC final notice to proceed. – Complete construction of the transmission line by December 31, 2020.	The 140-mile, 500 kV Aeolus to Bridger transmission project is underway and on-track to achieve commercial operation by the end of 2020.
2b	**<u>Energy Gateway Permitting</u>** • Continue permitting for the Energy Gateway transmission plan, with the following near-term targets: – For Segments D1, D3, E, and F, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. – For Segments D, E, and F, continue to support the projects by providing information and participating in public outreach. – For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.	Final environmental and records of decision have been issued for Gateway Segments D1, D3, E and F. PacifiCorp will continue the work necessary to meet requirements within the records of decision and will continue to meet regularly with the Bureau of Land Management to review progress. PacifiCorp continues to support Gateway Segment H (Boardman-to-Hemingway) consistent with the Joint Permit Funding Agreement. As a participant in the project PacifiCorp continues to collaborate with Idaho Power, the lead organization in the permitting process, by providing guidance on activities and plans associated with the permitting phase of the project.
2c	**<u>Wallula to McNary 230 kV Transmission Line</u>** • Complete Wallula to McNary project construction per plan with a 2018 expected in-service date. Continue to support the permitting and construction process for Walla Walla to McNary.	Wallula to McNary project is complete, and the line went in-service January 2019.

2d	**<u>Planning Studies</u>** • Complete planning studies that include proposed coal unit retirement assumptions from the 2017 IRP preferred portfolio and two other scenarios. • Summarize studies in the 2017 IRP Update.	Planning studies were completed in 2018 and included in PacifiCorp's 2017 IRP Update.
3a	**<u>Front Office Transactions</u>** • Acquire economic short-term firm market purchases for on-peak summer deliveries from 2017 through 2019 consistent with the Risk Management Policy and Commercial and Trading 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 the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month-forward, balance-of-month, day-ahead, and hour-ahead non-brokered transactions.	For 2018, PacifiCorp acquired approximately 2,225 MW to 2,765 MW of short-term firm market purchases inclusive of forward hedging transactions, not accounting for any offsetting hedging or balancing sales for delivery during the on-peak summer period. For 2019, as of end of September 2019, the company has acquired approximately 1,100 MW to 2,030 MW of short-term market purchases inclusive of forward hedging transactions, not accounting for any offsetting hedging sales for delivery during the on-peak summer period. For 2020, as of end of September 2019, the company has acquired approximately 150 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period inclusive of forward hedging transaction, not accounting for any offsetting hedging sales for delivery during the on-peak summer period.
4a	**<u>Class 2 DSM</u>** • Acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2017 IRP.	In 2017, PacifiCorp achieved the Action Plan target of 646 gigawatt hours (GWh). In 2018, PacifiCorp achieved 98 percent of the Action Plan target of 559 GWh.

<table>
<tr><td></td><td>
<table>
<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr>
<tr><td>2017</td><td>646</td><td>154</td></tr>
<tr><td>2018</td><td>559</td><td>128</td></tr>
</table>
*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.
</td><td></td></tr>
<tr><td>5a</td><td><u>Hunter Units 1 and 2</u>
• The U.S. Environmental Protection Agency (EPA)'s final Regional Haze Federal Implementation Plan (FIP) for Utah requires the installation of selective catalytic reduction (SCR) on Hunter Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
• As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.</td><td>PacifiCorp continues to support the state of Utah in its appeal of the EPA's FIP for Utah as it pertains to Hunter Units 1 and 2. The state of Utah submitted a revised Regional Haze State Implementation Plan (SIP) on July 3, 2019, for EPA review and approval. The EPA requested an additional minor revision to the SIP which Utah anticipates it will submit before year-end 2019. Litigation of the FIP appeal is currently held in abeyance while EPA reviews the revised SIP. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.</td></tr>
<tr><td>5b</td><td><u>Huntington Units 1 and 2</u>
• The EPA's final Regional Haze FIP for Utah requires the installation of SCR on Huntington Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
• As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.</td><td>PacifiCorp continues to support the state of Utah in its appeal of the EPA's FIP for Utah as it pertains to Hunter Units 1 and 2. The state of Utah submitted a revised Regional Haze State Implementation Plan (SIP) on July 3, 2019, for EPA review and approval. The EPA requested an additional minor revision to the SIP which Utah anticipates it will submit before year-end 2019. Litigation of the FIP appeal is currently held in abeyance while EPA reviews the revised SIP. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.</td></tr>
</table>

5c	**Dave Johnston Unit 3** • The EPA's final Regional Haze FIP requires the installation of SCR at Dave Johnston Unit 3 in 2019 or a commitment to shut down Dave Johnston Unit 3 by the end of 2027. PacifiCorp's commitment to the latter must be included in a permit before the 2019 compliance deadline. • PacifiCorp will update its analysis of the commitment to shut down Dave Johnston Unit 3 by the end of 2027 as part of its 2017 IRP Update.	PacifiCorp studied retirement of Dave Johnston Unit 3 in the 2017 IRP Update and the 2019 IRP. PacifiCorp does not plan to proceed with installation of SCR on Dave Johnston Unit 3, and will submit a permit revision before the end of 2019 to make the 2027 shut down date enforceable. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates in future IRP filings as applicable.
5d	**Jim Bridger Units 1 and 2** • The Wyoming Regional Haze SIP and EPA's final Regional Haze FIP for Wyoming require the installation of SCR on Jim Bridger Units 1 and 2 in 2021 and 2022. • PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units and will provide the associated analysis in its 2017 IRP Update.	PacifiCorp developed a Jim Bridger Regional Haze compliance alternative for the state of Wyoming and EPA to consider in 2018, and submitted a permit application with the state of Wyoming in February 2019. The state of Wyoming has incorporated the compliance alternative into a revised Wyoming Regional Haze SIP and a state permit. Wyoming is currently in the process of responding to public comments on the plan. It is expected that the state of Wyoming will submit the revised Wyoming Regional Haze SIP by year-end 2019 for EPA review and approval. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and analysis on Jim Bridger Units 1 and 2 in future IRP filings as applicable.
5e	**Naughton Unit 3** • PacifiCorp will update its economic analysis of natural gas conversion in its 2017 IRP Update.	PacifiCorp studied Naughton Unit 3 gas conversion in the 2017 IRP Update and the 2019 IRP. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information.
5f	**Wyodak** • Continue to pursue PacifiCorp's appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the	PacifiCorp continues to support the state of Wyoming in its appeal of the EPA's FIP for Wyoming as it pertains to Wyodak. The requirement for SCR at Wyodak is currently stayed as part of the FIP litigation proceedings. Please see

	compliance deadline for SCR under the FIP is currently stayed by the court. • If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.
5g	**<u>Cholla Unit 4</u>** • EPA has approved the Arizona SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025, with the option of natural gas conversion thereafter. • PacifiCorp will update its evaluation of Cholla Unit 4 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.
5h	**<u>Craig Unit 1</u>** • EPA is yet to approve the Colorado SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Craig Unit 1 as a coal-fueled resource by the end of 2025, with an option for natural gas conversion. • PacifiCorp will update its evaluation of Craig Unit 1 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update, as required.	Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings as applicable.

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define portfolio cost and risk analysis in the 2019 IRP. This analysis reflects a combination of specific planning assumptions related to coal unit retirements, potential Regional Haze compliance outcomes, Energy Gateway transmission investments, customer-preference renewable resources, targeted resource procurement outcomes (i.e., no new natural gas), market-reliance risk, market price assumptions, and CO_2 price assumptions. PacifiCorp further analyzed 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 2019 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 that qualify for federal income tax credits, FOTs, and energy efficiency resources are consistently selected. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2019 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 2019 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 (2019-2028) and long-term (2029-2038) resource strategies.

Acquisition Path Decision Mechanism

The Utah Commission 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 DSM target-setting/valuation processes. PacifiCorp uses the IRP and the IRP modeling tools to serve as decision support tools that can be used to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost. Table 9.3 summarizes PacifiCorp's 2019 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 9.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Higher sustained load growth	High economic drivers and high Utah and Wyoming industrial loads	• 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. • Increase acquisition of summer FOTs: on average, annual purchases are up 460 MW per year. • Increase and accelerate solar+battery procurement: solar+battery capacity begins to rise as early as 2021—by 2028, solar+battery capacity is increased by 103 MW. • Increase and accelerate stand-alone battery procurement: 165 MW of stand-alone battery capacity is accelerated into 2026. • Increase flexible capacity procurement: in 2028, new gas-peaking capacity increases by 370 MW. • Accelerate Class I DSM procurement: in 2028, new direct-load control capacity increases by 149 MW.	• Accelerate flexible capacity procurement: new peaking gas capacity is accelerated—increased by 759 MW in 2029 and by 959 MW in 2033. By the end of 2038, gas capacity is similar to a base load forecast case. • Defer procurement of stand-alone battery capacity: with an accelerated deployment of new gas capacity, stand-alone battery storage capacity is down by 450 MW in 2029, down by 255 MW by 2033.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Lower sustained load growth	Low economic drivers suppress load requirements with reduced demand from Utah and Wyoming industrial loads	• 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. • Reduce acquisition of summer FOTs: on average, annual purchases are down 220 MW per year. • Reduce and defer solar+battery capacity procurement: solar+battery capacity begins to fall as early as 2021—by 2028, solar+battery capacity is reduced by 220 MW. • Reduce and defer stand-alone battery procurement: stand-alone battery storage capacity declines beginning 2028 (180 MW). • Reduce flexible capacity procurement: 185 MW of new peaking gas capacity is deferred from 2026 to 2030. • Reduce energy efficiency procurement: through 2028, incremental energy efficiency procurement is down by 67 MW.	• Defer flexible capacity procurement: new peaking gas capacity remains relatively stable from 2030 through 2036—by 2038 new peaking gas capacity is down by 221 MW. • Adjust timing of solar+battery procurement: the timing for solar+battery capacity shifts—reduced by 720 MW by 2031, higher by 109 MW by 2035, and down by over 300 MW by 2038. • Increase stand-alone solar procurement: stand-alone solar is higher through the last ten years of the planning period—by 2038 it's up by 162 MW. • Reduce stand-along battery storage procurement: stand-alone battery storage capacity is down through the last ten years of the planning period—by 2038 it is reduced by 420 MW.
Higher sustained private generation penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• 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. • Delay procurement of flexible resource capacity: a 185 MW gas peaking plant is deferred by one year from 2026 to 2027.	• Small changes to the portfolio would require minimal changes to the resource acquisition strategy. • Timing differences in stand-alone solar, stand-alone battery and solar+battery 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 (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Lower sustained private generation penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• 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. • Delay procurement of flexible resource capacity: a 185 MW gas peaking plant is deferred by three years from 2026 to 2029.	• Accelerate procurement of flexible resource capacity: new gas peaking capacity increases by 370 MW in 2030. • Timing differences in stand-alone solar, stand-alone battery and solar+battery capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.
High CO_2 prices with accelerated coal retirements	Fossil-fired generation is faced with a high CO_2 price beginning in 2025 at $22.57/ton and reaching $83.69/ton by 2038 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 procurement of flexible resource capacity: new gas peaking capacity increases by 195 MW as early as 2023 and is 514 MW higher than the base case by 2028. • Increase procurement of market purchases: summer FOTs increase with the potential for accelerated coal retirements. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by 80 MW by 2028. • Accelerate procurement of direct-load control resources: by 2028, direct-load control capacity is up by 194 MW.	• Accelerate and increase procurement of flexible resource capacity: by 2029, new gas peaking capacity is 1,151 MW higher than in the base case and by 2038 it is 434 MW higher than the base case. • Accelerate and increase procurement of battery storage capacity: by 2038 battery storage capacity is increased by over 1,200 MW. • Accelerate procurement of direct-load control resources: by 2030, direct-load control capacity is up by 68 MW and in the 2031-2037 timeframe it is up by over 240 MW.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Jim Bridger and Naughton Units retire by the end of 2025	Retirements for Naughton Units 1-2 and Jim Bridger Units 3-4 all occur by the end of 2025.	• 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. • Increase procurement of market purchases: summer FOTs increase beginning 2026 and through 2028 by as much as 960 MW per year. • Accelerate procurement of flexible resource capacity: new gas peaking capacity is 210 MW higher in 2028. • Adjust timing and volumes for procurement of battery storage capacity: battery storage capacity is down by about 100 MW in 2024, but increases by about by about 500 MW by 2026. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by over 40 MW by 2028. • Accelerate procurement of direct-load control resources: by 2028, direct-load control capacity is up by 161 MW.	• Accelerate procurement of flexible resource capacity: new gas peaking capacity is between about 400 MW and 600 MW higher over the 2029 to 2034 timeframe, over 800 MW higher in the 2035-2036, and down by about 300 MW in 2037-2038. • Increase procurement of battery storage capacity: battery storage capacity is up by over 100 MW from 2030-2036, and is up by about 700 MW by 2038. • Accelerate procurement of renewable capacity: total renewable capacity is up by between 350 MW and over 1,200 MW from 2029-2037.
Low market prices	On average, levelized gas and power prices are down by approximately 25 percent relative to the base 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. • The near-term RFP process would assess potential changes to the resource mix, based on market bids that maximize value for customers, with potential changes to wind, solar, battery storage, and battery storage collated with solar.	• Accelerate procurement of flexible resource capacity: new gas peaking capacity increases by 342 MW in 2029 and by 1,518 MW in 2038. • Shifts in the precise timing and need for wind, solar, battery storage, and battery storage collated with solar would need to be evaluated through future competitive solicitation processes. • Reduce energy efficiency procurement: energy efficiency capacity is down by about 100 MW in this timeframe.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
High market prices	On average, levelized gas prices are up by about 25 percent and power prices by about 10 percent relative to the base 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. • Increase renewable procurement and battery storage procurement in the 2023 timeframe: higher prices increase renewable capacity by about 260 MW and battery storage capacity by over 400 MW. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by over 60 MW by 2028.	• Increase renewable procurement: higher prices increase renewable capacity by 720 MW in 2029 rising to over 1,200 MW by 2038. • Accelerate procurement of flexible resource capacity: new gas peaking capacity is higher by between 130 MW and 370 MW in the 2032-2036 timeframe, but down by over 500 MW in the 2037-2038 timeframe. • Battery storage capacity procurement would be adjusted in accordance with changes to gas capacity: battery storage capacity is down by about 300 MW in the 2032-2036 timeframe and up by 300-700 MW in the 2037-2038 timeframe. • Increase procurement of direct-load control resources: direct-load control capacity is up by between 40 MW and over 200 MW over the long term.
No customer-preference resource demand	No resources are added to meet customer-preference targets	• 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. • Reduce procurement of customer-preference renewables: total renewable capacity is down by nearly 300 MW through 2023, but up by 10 MW from 2024-2028.	• Longer term, the total volume of renewables is similar without customer preference resource demand. • Future RFP processes would evaluate timing adjustments for battery storage capacity and new gas peaking capacity; however, in aggregate, these capacity resources are not materially different from the base case.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
High customer-preference resource demand	Additional resources are added to meet higher customer-preference targets that exceed base case levels by over 3.5x in 2025 (5.7 GWh) rising to over 4.8x by 2038 (9.3 GWh).	• 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 procurement of renewable resources: by the 2024-2025 timeframe, renewable capacity is up by about 100 MW and by 2028, it is up by over 550 MW. • Accelerate procurement of battery storage capacity: by the 2024-2025 timeframe, battery storage capacity is up by about 50 MW and by 2028, it is up by over 130 MW. • Delay procurement of flexible resource capacity: new gas peaking capacity is 185 MW lower from 2026-2029. • Reduce procurement of market purchases: summer FOTs increase beginning 2026 and through 2028 by 20 to 160 MW over the 2024-2028 timeframe.	• Accelerate procurement of renewable resources: in the 2029-2038 timeframe, renewable capacity is up by over 570 MW in 2029 and up by 100 MW by 2030. • Accelerate procurement of battery storage capacity: in 2029 battery storage capacity is up by over 550 MW and in the 2029-2038 timeframe, battery storage capacity is up by over 280 MW.

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 the 2019 IRP. 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 the target 13 percent 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 2019 IRP includes a sensitivity (case S-06) 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 2018 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.

Differences between PacifiCorp's 2019 IRP preferred portfolio and case S-07 are driven by assumptions for Naughton Unit 3 and Cholla Unit 4. Case S-07 does not include the Naughton Unit 3 gas conversion and assumes Cholla Unit 4 retires in early 2025 instead of 2020. In the near-term, the preferred portfolio has lower summer FOTs, slight changes in the volumes and timing associated with DSM resources, and slight changes in customer-preference renewable resources. None of these differences have any bearing on the 2019 IRP action plan, which calls for, among other things, issuance of an all-source RFP and advancement of transmission investments that will enable adding new renewable resources to the system. Over the long term, the change in resources from case S-06 relative to the preferred portfolio are largely associated with timing; however, the overall long-term portfolio resource mix is similar to the resources included in the preferred portfolio and would not materially alter PacifiCorp's long-term resource procurement plans. Table 9.4 compares the 2019 IRP preferred portfolio with portfolio from sensitivity case S-06.

Table 9.4 – Comparison of the 2019 IRP Preferred Portfolio with Sensitivity Case S-06

2019 IRP Preferred Portfolio

	Capacity (MW)																				Resource Totals
Resource	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2019-2038**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	**505**
Gas- Peaking	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	813	-	**1,367**
DSM - Energy Efficiency	126	132	133	143	147	151	147	144	143	138	126	120	114	110	99	82	77	65	58	59	**2,315**
DSM - Load Control	4	-	7	-	18	-	8	7	-	-	133	8	-	12	-	-	15	4	59	169	**444**
Renewable - Wind	-	-	-	-	69	1,920	-	-	-	-	-	1,040	-	-	-	-	-	-	-	-	**3,029**
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	-	10	-	-	60	-	-	-	-	11	-	**81**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Utility Solar+Storage	-	-	159	64	3	2,154	-	-	-	-	359	500	-	-	475	-	-	419	909	702	**5,745**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage - Other	-	-	-	-	-	-	-	-	-	180	435	-	30	120	-	-	-	-	-	600	**1,365**
Front Office Transactions - Summer	998	719	493	503	498	131	126	191	264	1,163	1,375	1,274	1,249	1,281	1,373	1,375	1,374	1,277	1,374	1,375	**921**
Front Office Transactions - Winter	151	131	268	303	314	44	51	53	100	232	222	173	192	128	63	-	35	-	-	-	**123**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	(280)	(387)	-	-	(351)	-	(439)	(82)	(148)	(356)	-	-	-	-	-	-	-	-	-	**(2,042)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	(755)	-	-	(77)	-	(356)	-	-	-	(909)	(702)	**(2,799)**
Retire - Hydro	-	(1)	(169)	-	(1)	(20)	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	**(282)**
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	**(40)**
Expire - Wind PPA	-	(27)	(17)	(224)	(0)	(41)	-	(65)	(3)	-	(93)	(109)	(200)	(65)	(201)	(80)	-	(70)	(90)	-	**(1,284)**
Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	(2)	-	-	(67)	(49)	-	-	(36)	(209)	(1,024)	(11)	**(1,399)**
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	**(33)**
Coal Plant Gas Conversion Additions	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	**-**
Total	**1,279**	**922**	**488**	**788**	**1,048**	**3,988**	**333**	**75**	**422**	**800**	**2,211**	**3,089**	**1,234**	**1,598**	**1,453**	**1,301**	**1,467**	**1,485**	**1,706**	**2,160**	

Study includes Naughton 3 conversion at the beginning of 2020.
FOT in resource total are 20-year averages.

2019 IRP Preferred Portfolio less Sensitivity Case S-06

	Capacity (MW)																				Resource Totals
Resource	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2019-2038**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Gas- Peaking	-	-	-	-	-	-	-	185	-	(185)	(370)	370	-	-	-	-	-	-	-	-	**-**
DSM - Energy Efficiency	(9)	(2)	3	0	(5)	-	0	(4)	(0)	(0)	2	(0)	5	7	(0)	0	1	(1)	(1)	(3)	**(7)**
DSM - Load Control	-	-	(8)	-	8	-	-	-	-	(126)	126	8	(8)	-	-	-	-	-	(23)	(26)	**(50)**
Renewable - Wind	-	-	-	-	69	-	-	-	-	-	-	(60)	-	-	-	-	-	-	(92)	(58)	**(141)**
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	-	10	-	-	60	-	-	-	-	11	-	**81**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Utility Solar+Storage	-	-	-	-	(69)	36	-	-	-	-	-	500	(500)	(45)	(100)	-	-	419	(338)	-	**(97)**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage - Other	-	-	(15)	-	-	-	-	-	-	(30)	420	(360)	30	(45)	(195)	-	-	15	-	315	**135**
Front Office Transactions - Summer	(13)	(245)	(28)	(52)	(62)	(60)	(60)	(280)	(281)	(195)	37	4	(32)	(45)	(2)	298	298	191	(1)	5	**(526)**
Front Office Transactions - Winter	2	8	9	9	9	(9)	(9)	(9)	(11)	(11)	3	1	4	(8)	(4)	(300)	(299)	(305)	-	-	**(46)**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	(280)	(387)	-	-	(351)	-	(439)	(82)	(148)	(356)	-	-	-	-	-	-	-	-	-	**(2,042)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	(755)	-	-	(77)	-	(356)	-	-	-	(909)	(702)	**(2,799)**
Retire - Hydro	-	(1)	(169)	-	(1)	(20)	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	**(282)**
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	**(40)**
Expire - Wind PPA	-	(27)	(17)	(224)	(0)	(41)	-	(65)	(3)	-	(93)	(109)	(200)	(65)	(201)	(80)	-	(70)	(90)	-	**(1,284)**
Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	(2)	-	-	(67)	(49)	-	-	(36)	(209)	(1,024)	(11)	**(1,399)**
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	**(33)**
Coal Plant Gas Conversion Additions	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	**-**
Total	**(20)**	**(300)**	**(611)**	**(267)**	**(51)**	**(446)**	**(69)**	**(614)**	**(378)**	**(1,459)**	**(221)**	**67**	**(852)**	**(191)**	**(859)**	**(158)**	**(36)**	**38**	**(2,467)**	**(512)**	

FOT in resource total are 20-year averages.

Sensitivity Case S-06

	Capacity (MW)																				Resource Totals
Resource	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2019-2038**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	**505**
Gas- Peaking	-	-	-	-	-	-	-	-	-	185	370	-	-	-	-	-	-	-	813	-	**1,367**
DSM - Energy Efficiency	135	134	129	142	151	151	147	148	144	138	124	120	109	104	100	81	76	67	59	63	**2,322**
DSM - Load Control	4	-	15	-	10	-	8	7	-	126	7	-	8	12	-	-	15	4	83	195	**494**
Renewable - Wind	-	-	-	-	-	1,920	-	-	-	-	-	1,100	-	-	-	-	-	-	92	58	**3,170**
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Utility Solar+Storage	-	-	159	64	73	2,118	-	-	-	-	359	-	500	45	575	-	-	-	1,247	702	**5,842**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Storage - Other	-	-	15	-	-	-	-	-	-	210	15	360	-	165	195	-	-	(15)	-	285	1,230
Front Office Transactions - Summer	1,010	964	521	555	560	191	187	472	545	1,357	1,338	1,269	1,281	1,327	1,375	1,077	1,077	1,086	1,375	1,370	947
Front Office Transactions - Winter	149	123	259	294	305	53	60	62	111	243	219	172	188	136	67	300	334	305	-	-	**169**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Total	**1,299**	**1,222**	**1,099**	**1,055**	**1,099**	**4,433**	**402**	**688**	**800**	**2,259**	**2,432**	**3,022**	**2,087**	**1,788**	**2,312**	**1,459**	**1,503**	**1,447**	**4,173**	**2,672**	

Study includes Naughton 3 retirement at the end of 2019.
FOT in resource total are 20-year averages.

Resource Procurement Strategy

To acquire resources outlined in the 2019 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 2019 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, which is also being considered in revised rules being developed in Washington. 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

PacifiCorp offers a robust portfolio of Class 1 (demand response and direct-load control) and Class 2 (energy efficiency) 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 bases. 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 evaluate how to best incorporate potential Class 1 DSM programs into the broader all-source RFP process discussed above.

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 is being implemented with the wind repower project analyzed in the 2017 IRP), use the site for additional resources in the future, change fueling strategies or sources (as is being implemented for the Naughton Unit 3 gas conversion), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize 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.

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. Purchase power 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 2019 IRP, known and prospective environmental regulations can impact utilization of resources and investment decisions.

Compliance strategies will be affected by how and whether states or the federal government choose to implement greenhouse gas policies. 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, when commercially proven. 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. The purpose is solely to reduce customer exposure to net power cost volatility and adverse price movement. 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 periodically 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. PacifiCorp's current policy is also consistent with the guidelines that resulted from collaborative hedging workshops with parties in Utah, Oregon, Idaho and Wyoming that took place in 2011 and 2012.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits, value-at-risk (VaR) limits and time to expiry VaR (TEVaR) 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 these open 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 at fixed prices in gradual stages in advance of when it is required to reduce the size of this short position and associated customer risk. Likewise, on the power side, PacifiCorp either purchases or sells power in gradual stages in advance of anticipated open short or long positions to manage price volatility on behalf of customers.

Since 2003, PacifiCorp's hedge program has employed a portfolio approach of dollar cost averaging to progressively reduce net power cost risk exposure over a defined time horizon while adhering to best practice risk management governance and guidelines. PacifiCorp's current portfolio hedging approach is defined by increasing risk tolerance levels represented by progressively increasing percentage of net power costs across the forward hedging period. PacifiCorp incorporated a time to expiry value at risk (TEVaR) metric in May 2010. In May 2012, as a result of multiple hedging collaboratives, the company reintroduced natural gas percent hedge

volume limits of forecast requirements into its policy. There has been no conflict to-date between the new volume limits and PacifiCorp's VaR and TEVaR limits, although the volume limits would supersede in such conflict, consistent with the guidelines from the hedging collaboratives.

The primary governance of PacifiCorp's hedging activities is documented in the company's Risk Management Policy. In May 2010, PacifiCorp moved from hedging targets based on volume percentages to targets based on the "to expiry value-at-risk" or TEVaR metric. The primary goal of this change was to increase the transparency of the combined natural gas and power exposure by period. It enhances the progressive approach to hedging that PacifiCorp has employed for many years and provides the benefit of a more sophisticated measure of risk that responds to changes in the market and changes in open natural gas and power positions. Importantly, the TEVaR metric automatically reduces hedge requirements as commodity price volatility decreases and increases hedge requirements as correlations among commodities diverge, all the while maintaining the same customer risk exposure.

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 VaR and TEVaR and natural gas percent hedge volume limits.

The result of these program changes in combination with changes in the market (such as reduced volatility to which PacifiCorp's program automatically responds), has been a significant decrease in PacifiCorp's longer-dated hedge activity, *i.e.*, four years forward on a rolling basis.

As a result of the hedging collaboratives, PacifiCorp made the following material changes to its policy in May 2012: (l) a reduction in the standard hedge horizon from 48 months to 36 months and (2) a percent hedged range guideline for natural gas for each of the three forward l2-month periods, which includes a minimum natural gas open position in each of the forward 12-month periods. The percent hedged range guideline is greater for the first rolling twelve months and gradually smaller for the second and third rolling twelve-month periods. PacifiCorp also agreed to provide a new confidential semi-annual hedging report.

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. In addition, PacifiCorp reduces the amount of hedging required to achieve a given risk tolerance through its portfolio hedge management approach, which takes into account offsetting exposures when these commodities are correlated, as opposed to hedging commodity exposures to natural gas and power in isolation without regard for offsets.

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 economic generation relative to customer load requirements at a given point in time.

PacifiCorp hedges its net energy (combined natural gas and power) position on a portfolio basis to take full advantage of any natural offsets between its long power and short natural gas positions. Analysis has shown that a "hedge only power" or "hedge only natural gas" approach results in higher risk (*i.e.*, a wider distribution of outcomes). There is a natural need for an electric company with natural gas fired electricity generation assets to have a hedge program that simultaneously manages natural gas and power open positions with appropriate coordinated metrics. PacifiCorp's risk management department incorporates daily updates of forward prices for natural gas, power, volatilities and correlations to establish daily changes in open positions and risk metrics which inform the hedging decisions made every day by company traders.

PacifiCorp's hedge program does not rely on a long power position. However, the company's hedge program takes into account its full portfolio and utilizes continuously updated correlations of natural gas and power prices and thereby takes advantage of offsetting natural gas and power positions in circumstances when prices are correlated and a forecast long power position offsets a forecast short natural gas position. This has the effect of reducing the amount of natural gas hedging that PacifiCorp would otherwise pursue. Ignoring this correlation would instead result in the need for more natural gas hedges to achieve the same level of customer risk reduction.

PacifiCorp's customers have benefited from offsetting power and natural gas positions. Power and natural gas prices are closely related because natural gas is often the fuel on the margin in efficient dispatch, as is practiced throughout the western U.S. This means power sales tend to be more valuable in periods when natural gas is high cost, producing revenues that are a credit or offset to the high cost fuel. If spot natural gas prices depart from prior forward prices, power prices will tend to do so in the same direction, thereby naturally hedging some of the unexpected cost variance.

Effectiveness Measure

The goal of the hedging program is to reduce volatility in PacifiCorp's net power costs primarily due to changes in market prices. The goal is not to "beat the market" and, therefore, should not be measured on the basis of whether it has made or lost money for customers. This reduction in volatility is calculated and reported in the company's confidential semi-annual hedging report which it began producing as a result of the hedging collaborative.

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. The company also considers, with respect to options, the likelihood of disallowance of the option premium in its six jurisdictions. There is no functional difference between financial swaps and fixed price physical transactions; both instruments are equally effective in hedging the PacifiCorp's fixed price exposure.

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 2019 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.

2019 Integrated *resource plan*

VOLUME II – APPENDICES A-L
OCTOBER 18, 2019

This 2019 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Marengo Wind Project
Transmission Line
Electric Meter
Pavant III Solar Plant

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APPENDIX A – LOAD FORECAST DETAILS

Introduction

This appendix reviews the load forecast used in the modeling and analysis of the 2019 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 in order 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

PacifiCorp updated its load forecast in September 2018. The compound annual energy growth rate for the 10-year period (2019 through 2028) is 0.87 percent. Relative to the load forecast prepared for the 2017 IRP Update, PacifiCorp 2028 energy forecasted energy requirement increased in all jurisdictions other than Wyoming and Idaho, while PacifiCorp system energy requirement increased approximately 3.15 percent. Figure A.1 has a comparison of energy forecasts from the 2019 IRP to the 2017 IRP Update.

Figure A.1 – PacifiCorp System Energy Load Forecast Change, at Generation, pre-DSM

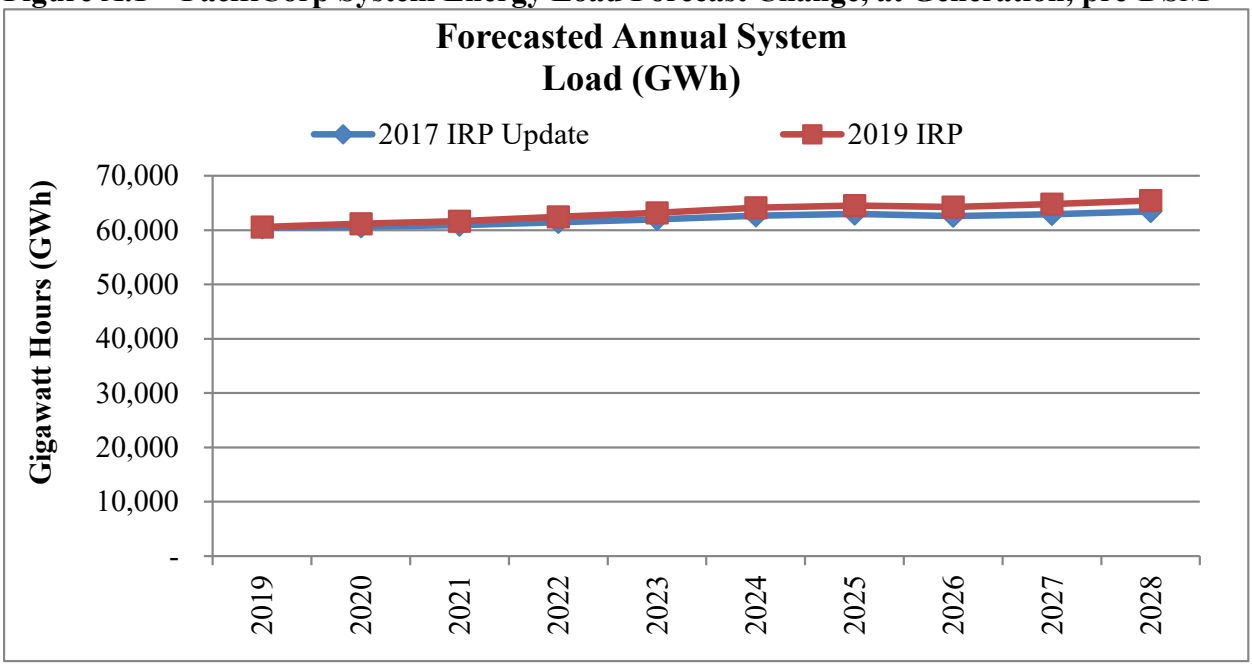


Table A.1 and Table A.2 show the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures (Class 2 DSM).[1] Table A.3 and Table A.4 show the forecast changes relative to the 2017 IRP Update load forecast for loads and coincident system peak, respectively.

Table A.1 Forecasted Annual Load, 2019 through 2028 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2019	60,555,090	15,116,420	4,648,980	888,050	25,905,480	10,034,340	3,961,820
2020	61,200,990	15,458,460	4,683,290	894,090	26,240,960	9,947,800	3,976,390
2021	61,668,220	15,762,730	4,696,950	886,220	26,490,100	9,844,530	3,987,690
2022	62,430,120	16,073,620	4,724,840	883,300	26,889,210	9,851,110	4,008,040
2023	63,189,850	16,226,410	4,756,440	881,850	27,359,260	9,935,110	4,030,780
2024	64,099,060	16,422,560	4,802,810	882,180	27,876,700	10,058,210	4,056,600
2025	64,561,310	16,522,910	4,821,500	877,420	28,220,370	10,052,750	4,066,360
2026	64,235,860	16,669,290	4,855,450	873,460	27,647,290	10,110,510	4,079,860
2027	64,827,020	16,821,000	4,892,190	867,600	27,944,390	10,210,990	4,090,850
2028	65,443,430	17,016,870	4,944,450	863,690	28,255,530	10,260,170	4,102,720
Compound Annual Growth Rate							
2019 - 2028	**0.87%**	**1.32%**	**0.69%**	**-0.31%**	**0.97%**	**0.25%**	**0.39%**

[1] Class 2 demand-side management (DSM) load reductions are included as resources in the System Optimizer model.

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

Year	Total	OR	WA	CA	UT	WY	ID
2019	10,197	2,406	767	147	4,786	1,307	784
2020	10,279	2,447	774	146	4,827	1,301	785
2021	10,357	2,491	779	145	4,862	1,291	788
2022	10,468	2,526	786	144	4,928	1,293	791
2023	10,581	2,543	792	146	5,005	1,301	794
2024	10,687	2,555	788	141	5,088	1,324	791
2025	10,786	2,579	808	143	5,155	1,316	784
2026	10,818	2,596	815	142	5,144	1,322	799
2027	10,895	2,613	822	141	5,186	1,332	800
2028	10,985	2,629	830	141	5,250	1,337	799
Compound Annual Growth Rate							
2019 - 2028	**0.83%**	**0.99%**	**0.88%**	**-0.49%**	**1.03%**	**0.25%**	**0.21%**

Table A.3 – Annual Load Change: September 2018 Forecast less November 2017 Forecast (Megawatt-hours) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2019	106,560	(31,660)	46,810	(11,290)	33,630	28,140	40,930
2020	516,600	286,760	60,670	2,420	211,460	(81,630)	36,920
2021	715,580	544,030	76,140	2,350	279,490	(219,250)	32,820
2022	978,340	757,450	90,500	3,300	389,520	(288,990)	26,560
2023	1,206,810	803,410	103,860	5,170	556,490	(281,790)	19,670
2024	1,437,060	851,760	113,690	6,560	712,080	(257,650)	10,620
2025	1,556,540	893,570	120,030	8,490	842,170	(307,270)	(450)
2026	1,657,600	947,910	127,000	8,850	905,310	(318,900)	(12,570)
2027	1,904,560	1,004,000	137,810	6,900	1,069,810	(287,310)	(26,650)
2028	1,998,380	1,062,760	152,300	3,490	1,157,930	(332,600)	(45,500)

Table A.4 – Annual Coincident Peak Change: September 2018 Forecast less November 2017 Forecast (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2019	192	50	10	(0)	101	27	4
2020	241	88	10	0	123	18	2
2021	248	123	12	(0)	111	3	(1)
2022	278	149	13	(0)	125	(5)	(4)
2023	314	157	15	(0)	155	(5)	(7)
2024	344	164	5	(3)	185	7	(15)
2025	366	173	17	(0)	194	(8)	(10)
2026	396	182	19	(0)	222	(10)	(16)
2027	433	192	20	(1)	253	(8)	(23)
2028	449	201	22	(3)	272	(14)	(29)

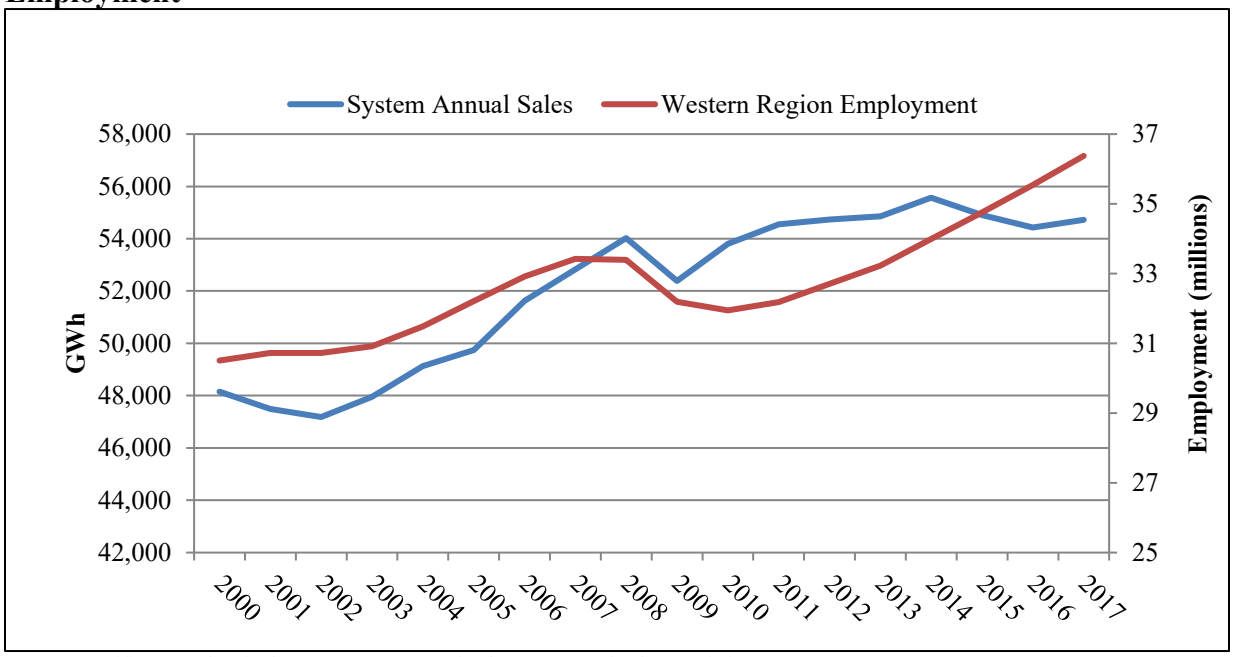
Load Forecast Assumptions

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 2017, 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 2008-2009 recession.

Figure A.2 – PacifiCorp Annual Retail Sales 2000 through 2017 and Western Region Employment

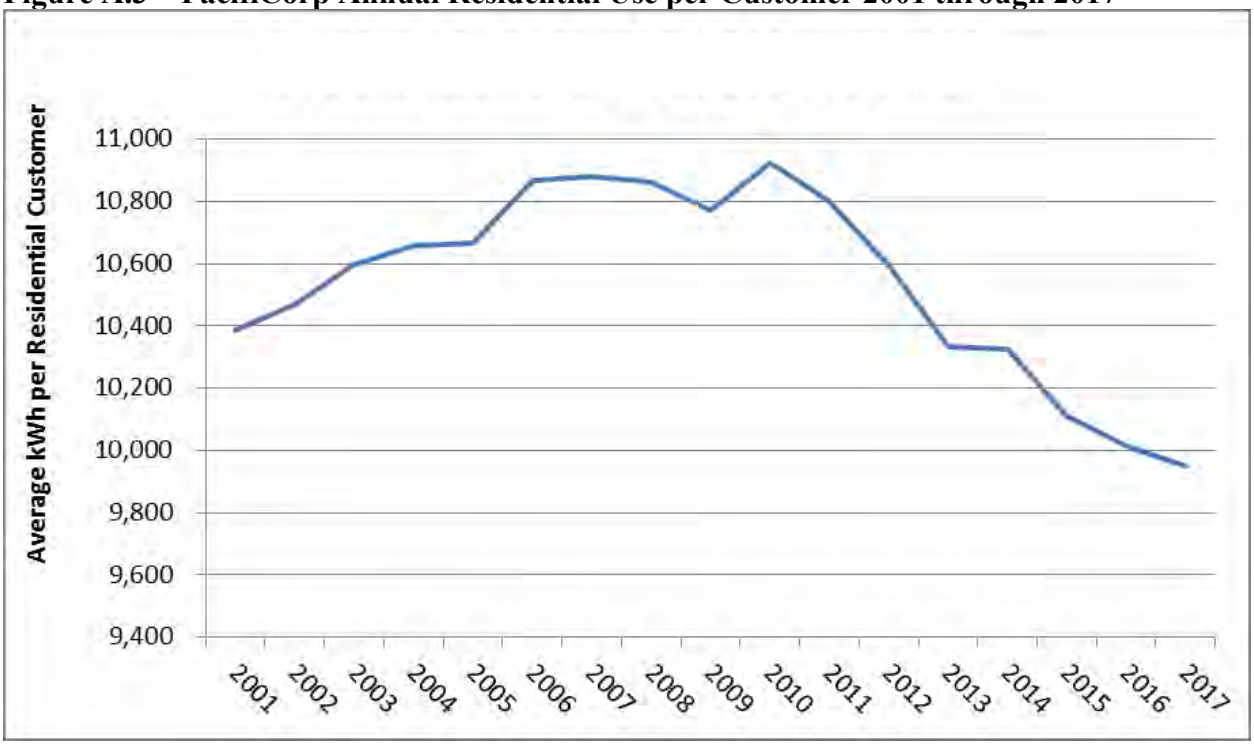


Sources: PacifiCorp and United States Department of Labor, Bureau of Labor Statistics

The 2019 IRP forecast utilizes the February 2018 release of IHS Markit economic driver forecast; whereas the 2017 IRP Update relies on the February 2017 release from IHS Markit. As discussed below, although both the economic and demographic forecast is relatively unchanged from the 2017 IRP Update, the load forecast has increased. There are two changes which are driving the 2019 IRP load and peak forecast higher. First, higher projected demand from data centers are driving up the commercial forecast; whereas, a higher residential customer forecast is driving a higher residential forecast.

Figure A.3 shows the weather normalized average system residential use per customer. As illustrated, residential use per customer has been decreasing since 2010.

Figure A.3 – PacifiCorp Annual Residential Use per Customer 2001 through 2017

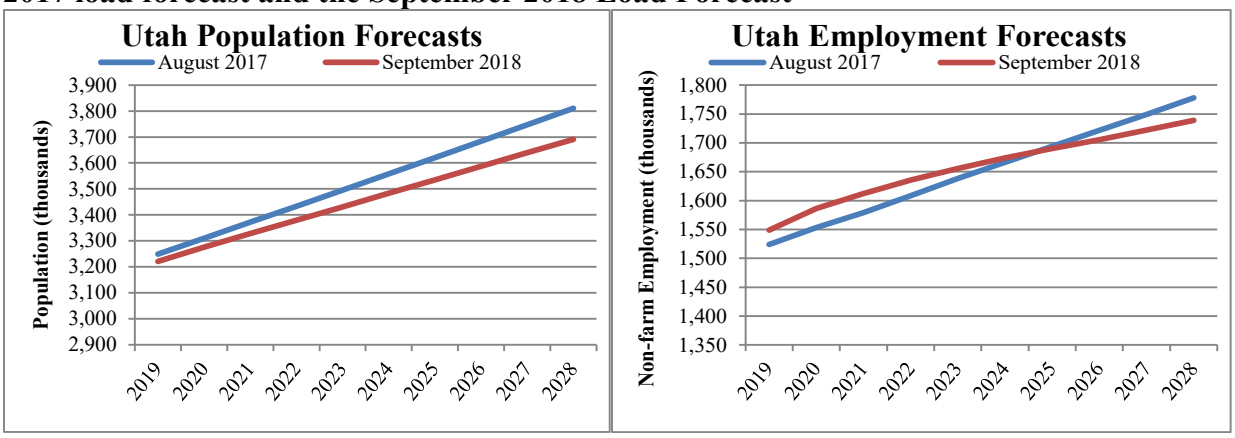


Residential use per customer across all six of PacifiCorp's states is changing due to increased energy efficiency driven primarily by lighting efficiency standards resulting from the 2007 Federal Energy legislation. In addition, there has been a shift from single-family and manufactured housing to multi-dwelling units and a trend of replacing older electric appliances with more energy efficient appliances.

Utah

PacifiCorp serves 26 of the 29 counties in the state of Utah, with Salt Lake City being the largest metropolitan area served by the company within the state. Utah is expected to experience an annual increase of 1.30 percent in non-farm employment over the next 10 years. Figure A.4 shows the change in population and employment forecasts between the 2017 IRP Update relative to the 2019 IRP forecast. This figure illustrates that the population forecast is slightly lower. The employment forecast is slightly higher over the 2019 through 2024 timeframe, while it is lower over the 2025 through 2028 timeframe. Relative to the load forecast prepared for the 2017 IRP Update, the Utah 2028 retail load forecast increased approximately 4.95 percent. This increase is attributable to higher projected demand from data centers driving up the commercial forecast and higher residential demand due to higher projected residential customers.

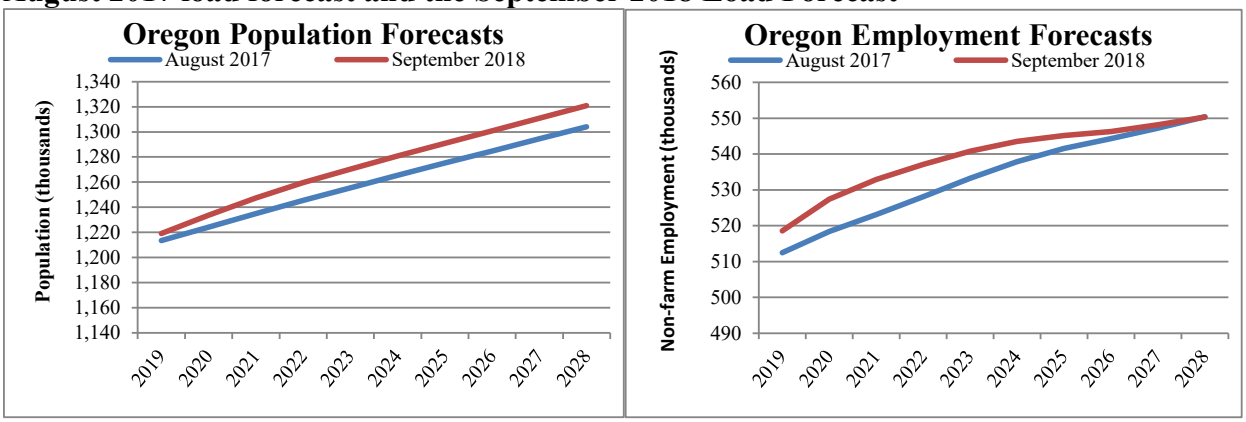
Figure A.4 – IHS Global Insight Utah Household and Employment forecasts from the August 2017 load forecast and the September 2018 Load Forecast



Oregon

PacifiCorp serves 25 of the 36 counties in Oregon, but provided only 26.6 percent of ultimate electric retail sales in the state of Oregon in 2017.[2] Figure A.5 shows the change in population and employment forecasts for the 2017 IRP Update relative to the 2019 IRP forecast. This figure illustrates that the Oregon forecast of population and employment have both increased slightly. Relative to the load forecast prepared for the 2017 IRP Update, the Oregon 2028 retail load forecast has increased approximately 5.73 percent.

Figure A.5 – IHS Global Insight Oregon Household and Employment forecasts from the August 2017 load forecast and the September 2018 Load Forecast



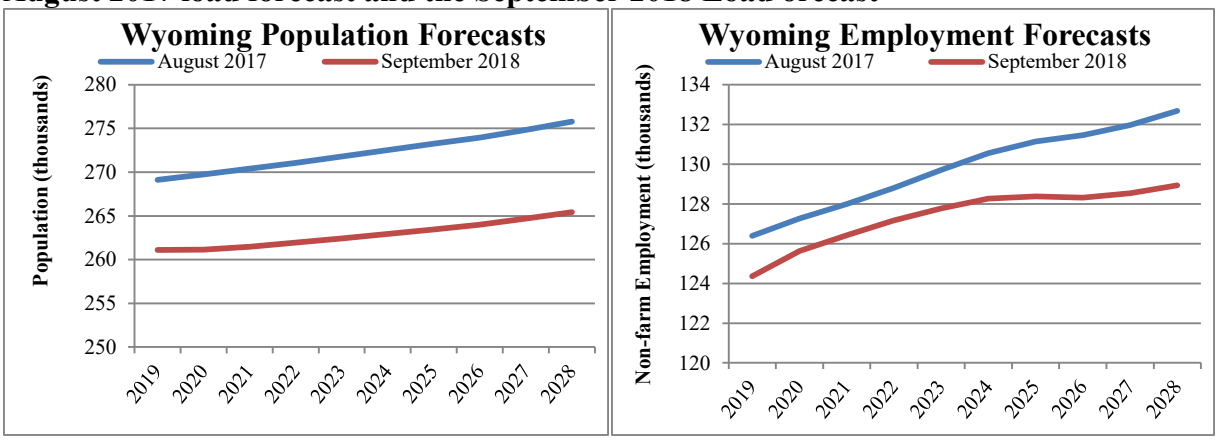
Wyoming

PacifiCorp serves 15 of the 23 counties in Wyoming, with Casper being the largest metropolitan area served by the company in the state. Industrial sales make up approximately 74 percent of PacifiCorp's Wyoming sales. Figure A.6 shows the change in population and employment forecasts for the 2017 IRP Update relative to the 2019 IRP forecast. This figure illustrates that the Wyoming population forecast used in the 2019 IRP forecast has decreased relative to the 2017 IRP Update. Similarly, the employment forecast has also decreased. Relative to the load forecast

[2] Source: Oregon Public Utility Commission, 2017 Oregon Utility Statistics.

prepared for the 2017 IRP Update, the Wyoming 2028 retail load forecast decreased approximately 4.27 percent.

Figure A.6 – IHS Global Insight Wyoming Household and Employment forecasts from the August 2017 load forecast and the September 2018 Load orecast

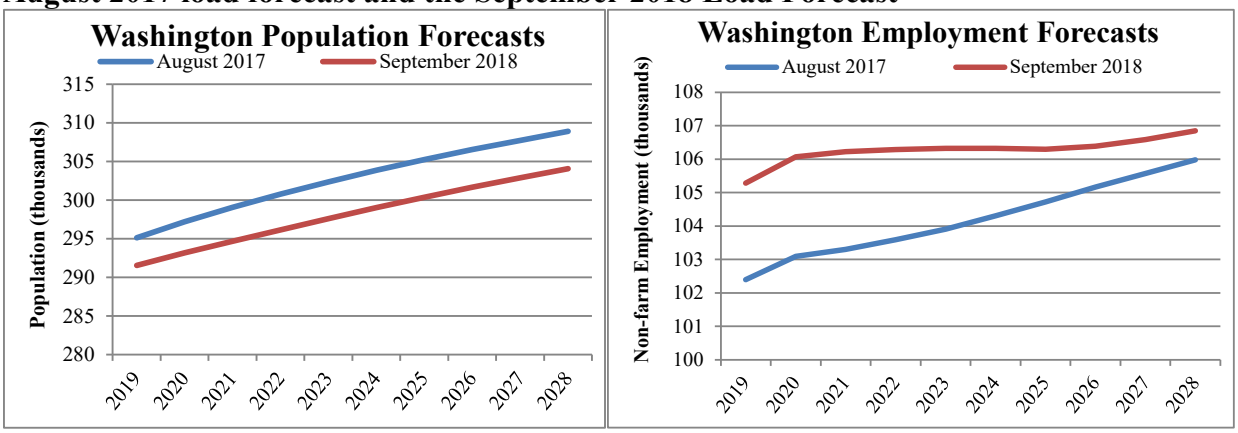


A risk to the Wyoming forecast is commodity prices, such as oil and natural gas, where volatility in prices and profitability can lead to swings in production and employment which translates to potential swings in the retail sales forecast.

Washington

PacifiCorp serves the following counties in Washington State: Benton, Columbia, Cowlitz, Garfield, Walla Walla, and Yakima. Yakima is the most populated county that the company serves in Washington State and has a large concentration of agriculture and food processing businesses. Residential and commercial sales are roughly equal in size each making up approximately 39 percent of PacifiCorp's Washington sales. Figure A.7 shows the change in population and employment forecasts for the 2017 IRP Update relative to the 2019 IRP forecast. This figure illustrates that the population forecast is lower, while the employment forecast has increased. Relative to the load forecast prepared for the 2017 IRP Update, the Washington 2028 retail load forecast increased approximately 1.78 percent.

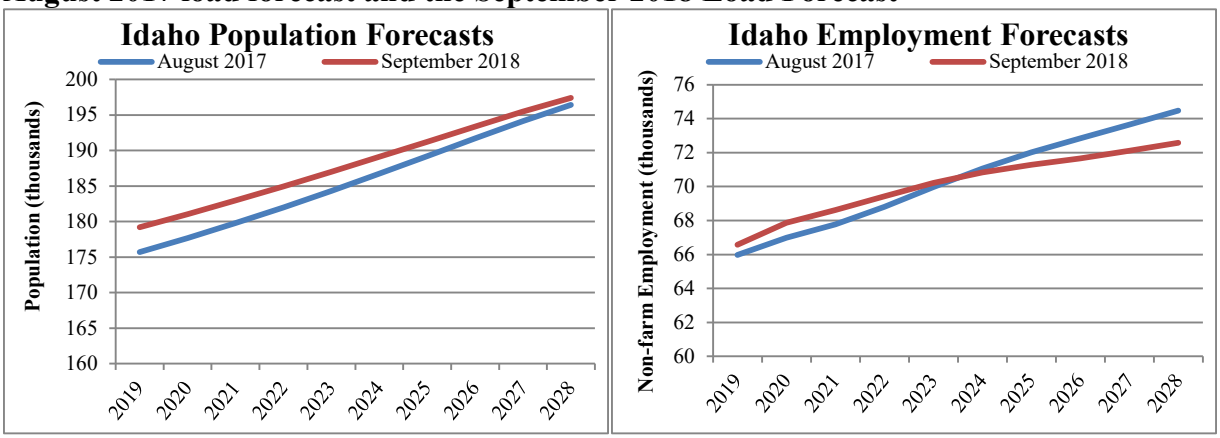
Figure A.7 – IHS Global Insight Washington Household and Employment forecasts from the August 2017 load forecast and the September 2018 Load Forecast



Idaho

PacifiCorp serves 14 of the 44 counties in the state of Idaho, with the majority of the company's service territory in rural Idaho. Industrial sales make up approximately 50 percent of the company's Idaho sales. Figure A.8 shows the change in population and employment forecasts for the 2017 IRP Update relative to the 2019 IRP forecast. This figure illustrates that the forecast for population has increased, while the employment forecast has increased over the 2019 to 2023 timeframe and declined over the 2024 to 2028 timeframe. Relative to the load forecast prepared for the 2017 IRP Update, the Idaho 2028 retail load forecast decreased approximately 1.32 percent.

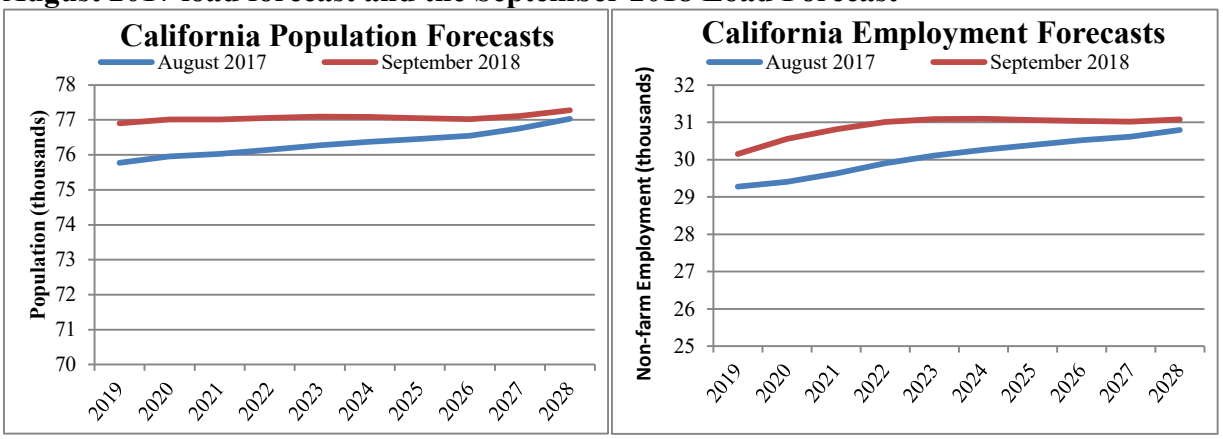
Figure A.8 – IHS Global Insight Washington Household and Employment forecasts from the August 2017 load forecast and the September 2018 Load Forecast



California

The four northern California counties served by PacifiCorp are largely rural, which include Del Norte, Modoc, Shasta and Siskiyou Counties. Crescent City is the largest metropolitan area served by the company in California. Residential sales make up approximately 50 percent of the company's California sales. Figure A.9 shows the change in population and employment forecasts for the 2017 IRP Update relative to the 2019 IRP forecast. This figure illustrates that the population and employment forecasts have increased. Relative to the load forecast prepared for the 2017 IRP Update, the California 2028 retail load forecast increased 0.40 percent before energy efficiency (and decreased 0.85% after accounting for energy efficiency savings).

Figure A.9 – IHS Global Insight California Household and Employment forecasts from the August 2017 load forecast and the September 2018 Load Forecast

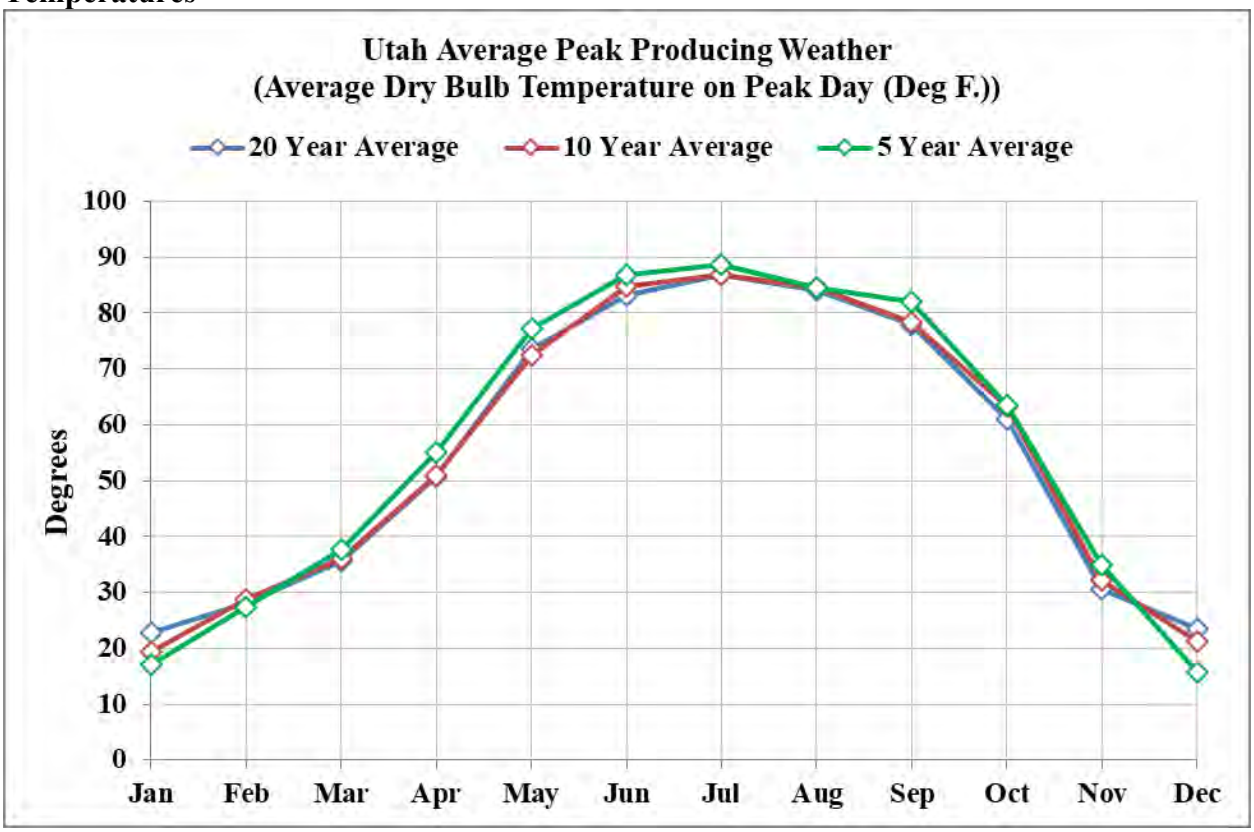


Weather

PacifiCorp's load forecast is based on normal weather defined by the 20-year time period of 1998-2017. The company updated its temperature spline models to the five-year time period of 2013-2017. PacifiCorp's spline models are used to model the commercial and residential class temperature sensitivity at varying temperatures.

PacifiCorp has reviewed the appropriateness of using the average weather from a shorter time period as its "normal" peak weather. Figure A.10 indicates that peak producing weather does not change significantly when comparing five, 10, or 20 year average weather.

Figure A.10 - Comparison of Utah 5, 10, and 20 Year Average Peak Producing Temperatures



Statistically Adjusted End-Use ("SAE")

PacifiCorp 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. PacifiCorp uses ITRON for its load forecasting software and services, as well as 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

PacifiCorp 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 PacifiCorp through a regional business manager (RBM).

Actual Load Data

With the exception of the industrial class, PacifiCorp uses actual load data from January 2000 through February 2018. The historical data period used to develop the industrial monthly sales is from January 2000 through February 2018 in Utah, Wyoming, and Washington, January 2002 through February 2018 in Idaho, and January 2003 through February 2018 in California and January 2008 through February 2018 in Oregon.

The following tables are the annual actual retail sales, non-coincident peak, and coincident peak by state used in calculating the 2019 IRP retail sales forecast.

Table A.5 - Weather Normalized Jurisdictional Retail Sales 2000 through 2017

System Retail Sales - Megawatt-hours (MWh)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	776,330	3,094,742	14,047,381	18,765,857	4,099,269	7,373,138	**48,156,718**
2001	778,256	2,987,391	13,529,960	18,490,759	4,020,032	7,680,903	**47,487,300**
2002	800,256	3,218,294	13,097,842	18,642,679	4,017,549	7,405,485	**47,182,104**
2003	819,413	3,243,349	13,071,848	19,279,071	4,067,427	7,471,935	**47,953,042**
2004	845,263	3,300,658	13,188,745	19,880,615	4,101,526	7,808,927	**49,125,734**
2005	835,878	3,232,797	13,199,197	20,253,628	4,211,933	8,011,258	**49,744,691**
2006	859,459	3,348,273	13,911,150	21,117,901	4,130,862	8,252,936	**51,620,581**
2007	874,813	3,384,194	14,023,385	21,983,724	4,076,966	8,481,524	**52,824,605**
2008	866,625	3,413,508	13,771,921	22,691,490	4,073,872	9,209,482	**54,026,899**
2009	828,967	2,965,022	13,128,912	22,157,832	4,048,793	9,258,055	**52,387,581**
2010	841,471	3,426,215	13,158,282	22,661,371	4,052,934	9,664,860	**53,805,133**
2011	803,462	3,472,522	13,029,055	23,457,892	4,018,089	9,765,559	**54,546,579**
2012	785,674	3,518,810	13,044,180	23,859,599	4,045,878	9,475,326	**54,729,467**
2013	775,001	3,549,834	13,081,879	23,839,238	4,059,599	9,551,554	**54,857,105**
2014	775,699	3,544,391	13,136,140	24,418,898	4,105,424	9,587,978	**55,568,531**
2015	747,798	3,468,932	13,093,004	24,117,031	4,102,238	9,377,276	**54,906,279**
2016	757,112	3,491,849	13,185,654	23,796,978	4,041,996	9,153,908	**54,427,497**
2017	760,943	3,574,912	13,164,078	23,707,035	4,080,132	9,433,527	**54,720,628**
Compound Annual Growth Rate							
2000-17	**-0.12%**	**0.85%**	**-0.38%**	**1.38%**	**-0.03%**	**1.46%**	**0.75%**

*System retail sales do not include sales for resale

Table A.6 - Non-Coincident Jurisdictional Peak 2000 through 2017

Non-Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	176	686	2,603	3,684	785	1,062	**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	**9,318**
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	1,338	**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**
Compound Annual Growth Rate							
2000-17	**0.06%**	**1.13%**	**0.68%**	**1.73%**	**1.09%**	**1.44%**	**1.27%**

*Non-coincident peaks do not include sales for resale

Table A.7- Jurisdictional Contribution to Coincident Peak 2000 through 2017

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**
Compound Annual Growth Rate							
2000-17	**-0.08%**	**0.74%**	**0.48%**	**1.70%**	**0.24%**	**1.71%**	**1.17%**

*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, 2017.

Forecast Methodology Overview

Class 2 Demand-side Management Resources in the Load Forecast

PacifiCorp modeled Class 2 DSM as a resource option to be selected as part of a cost-effective portfolio resource mix using the company's capacity expansion optimization model, System Optimizer. The load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM; System Optimizer then determines the amount of Class 2 DSM—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 Class 2 DSM supply curves, along with the economic screening provided by System Optimizer, determines the cost-effective mix of Class 2 DSM 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 forecast 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 2018. For the residential class, PacifiCorp forecasts the number of customers using IHS Global Insight's forecast of each state's number of population as the major driver.

For the 2019 IRP, PacifiCorp improved its residential customer forecasting methodology by adopting a differenced model approach in the development of the residential customer forecast. Rather than directly forecasting the number of customers as has been done in previous years, the differenced model predicts the monthly change in number of customers. The changes are accumulated and added to the initial number of customers to generate the final customer forecast. PacifiCorp had observed that directly forecasted customers, as done in previous years, consistently produced an under forecast of residential customers. PacifiCorp performed a historical comparison of the forecasted results using both methods against actual customer counts and determined the differenced model produced a more accurate customer forecast. As such the model was used to forecast load for the 2019 IRP, and resulted in an increase in the overall residential customer projections.

PacifiCorp 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 PacifiCorp'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, PacifiCorp prepares individual forecasts based on input from the customer and information provided by the RBM's.

After PacifiCorp 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 average monthly historical peak-producing weather for the 20-year period, 1998 through 2017. Second, PacifiCorp 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 as identified above, 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.

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.8 – System Annual Retail Sales Forecast 2019 through 2028, post-DSM

System Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2019	16,212,700	18,034,090	18,920,232	1,466,024	133,696	**54,766,743**
2020	15,854,942	18,459,331	18,954,765	1,462,213	133,807	**54,865,059**
2021	15,638,202	18,734,789	18,834,645	1,458,187	132,854	**54,798,677**
2022	15,616,831	18,954,503	18,818,871	1,454,137	132,066	**54,976,408**
2023	15,631,036	19,074,719	18,859,396	1,449,880	131,097	**55,146,128**
2024	15,713,571	19,209,491	18,950,500	1,444,465	130,381	**55,448,408**
2025	15,659,140	19,230,120	18,896,281	1,437,742	128,815	**55,352,098**
2026	15,674,375	19,326,384	17,955,352	1,430,140	127,588	**54,513,839**
2027	15,702,419	19,410,838	18,013,973	1,421,958	126,313	**54,675,500**
2028	15,792,344	19,488,236	18,053,413	1,413,928	125,383	**54,873,304**
Compound Annual Growth Rate						
2019-28	**-0.29%**	**0.87%**	**-0.52%**	**-0.40%**	**-0.71%**	**0.02%**

Residential

Over the 2019-2028 timeframe, the average annual growth of the residential class sales forecast decreased from -0.28 percent in the 2017 IRP Update to -0.29 percent in the 2019 IRP. The number of residential customers across PacifiCorp's system is expected to grow at an annual average rate of 1.33 percent, reaching approximately 1.9 million customers in 2028, with Rocky Mountain Power states adding 1.64 percent per year and Pacific Power states adding 0.84 percent per year.

Commercial

Average annual growth of the commercial class sales forecast increased from 0.18 percent annual average growth in the 2017 IRP Update to 0.87 percent expected average annual growth. The number of commercial customers across PacifiCorp's system is expected to grow at an annual average rate of 0.95 percent, reaching approximately 233,000 customers in 2028, with Rocky Mountain Power states adding 1.20 percent per year and Pacific Power states adding 0.61 percent per year.

Industrial

Average annual growth of the industrial class sales forecast decreased from -0.23 percent annual average growth in the 2017 IRP Update to -0.52 percent expected annual growth. 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.9 summarizes Oregon state forecasted retail sales growth by customer class.

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

Oregon Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2019	5,633,553	5,434,085	1,793,918	327,801	39,963	**13,229,320**
2020	5,585,633	5,629,864	1,801,507	327,928	40,220	**13,385,151**
2021	5,556,225	5,790,809	1,794,568	327,934	40,180	**13,509,716**
2022	5,556,664	5,918,154	1,786,929	327,933	40,220	**13,629,900**
2023	5,560,848	5,902,220	1,782,399	327,944	40,250	**13,613,661**
2024	5,585,036	5,896,025	1,782,806	327,778	40,386	**13,632,030**
2025	5,562,845	5,865,984	1,778,446	327,419	40,289	**13,574,983**
2026	5,564,157	5,851,239	1,781,633	327,076	40,308	**13,564,414**
2027	5,571,868	5,840,305	1,784,666	326,715	40,326	**13,563,879**
2028	5,605,191	5,846,409	1,791,562	326,393	40,460	**13,610,015**
Compound Annual Growth Rate						
2019-28	**-0.06%**	**0.82%**	**-0.01%**	**-0.05%**	**0.14%**	**0.32%**

Washington

Table A.10 summarizes Washington state forecasted retail sales growth by customer class.

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

Washington Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2019	1,592,714	1,578,131	784,573	158,742	9,629	**4,123,789**
2020	1,570,960	1,592,676	786,855	158,600	9,645	**4,118,735**
2021	1,554,764	1,588,547	783,146	158,437	9,592	**4,094,486**
2022	1,548,303	1,585,273	778,282	158,162	9,546	**4,079,565**
2023	1,545,173	1,580,260	773,376	157,836	9,484	**4,066,130**
2024	1,548,861	1,578,084	772,198	157,483	9,442	**4,066,068**
2025	1,540,807	1,566,204	768,629	157,091	9,342	**4,042,072**
2026	1,538,798	1,560,228	768,325	156,638	9,270	**4,033,259**
2027	1,537,675	1,556,561	768,111	156,191	9,197	**4,027,735**
2028	1,543,009	1,559,989	769,585	155,719	9,154	**4,037,455**
Compound Annual Growth Rate						
2019-28	**-0.35%**	**-0.13%**	**-0.21%**	**-0.21%**	**-0.56%**	**-0.23%**

California

Table A.11 summarizes California state forecasted sales growth by customer class.

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

California Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2019	367,897	235,353	58,162	85,073	1,862	**748,349**
2020	361,826	233,214	67,127	84,597	1,862	**748,625**
2021	355,511	229,650	66,226	84,195	1,848	**737,430**
2022	352,031	226,864	65,636	83,848	1,836	**730,214**
2023	349,717	223,699	64,992	83,434	1,820	**723,662**
2024	348,835	220,828	64,281	82,916	1,808	**718,667**
2025	345,089	216,362	63,212	82,405	1,782	**708,850**
2026	341,104	212,623	62,272	81,891	1,760	**699,651**
2027	335,738	208,827	61,282	81,350	1,738	**688,935**
2028	331,144	205,609	60,463	80,790	1,718	**679,724**
Compound Annual Growth Rate						
2019-28	**-1.16%**	**-1.49%**	**0.43%**	**-0.57%**	**-0.90%**	**-1.06%**

Utah

Table A.12 summarizes Utah state forecasted sales growth by customer class.

Table A.12 – Forecasted Retail Sales Growth in Utah, post-DSM

Utah Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2019	6,958,632	8,924,202	7,530,762	227,083	68,050	**23,708,729**
2020	6,722,640	9,127,823	7,641,629	226,518	67,972	**23,786,583**
2021	6,585,633	9,255,377	7,650,500	225,843	67,339	**23,784,691**
2022	6,586,282	9,355,618	7,689,331	225,172	66,786	**23,923,189**
2023	6,610,009	9,503,731	7,719,130	224,471	66,122	**24,123,463**
2024	6,664,829	9,652,768	7,763,907	223,747	65,575	**24,370,827**
2025	6,659,418	9,744,139	7,768,559	222,910	64,592	**24,459,618**
2026	6,686,629	9,887,868	6,828,384	222,092	63,782	**23,688,755**
2027	6,722,653	10,010,002	6,850,869	221,261	62,940	**23,867,725**
2028	6,788,210	10,091,495	6,900,904	220,444	62,269	**24,063,321**
Compound Annual Growth Rate						
2019-28	**-0.28%**	**1.38%**	**-0.97%**	**-0.33%**	**-0.98%**	**0.17%**

Idaho

Table A.13 summarizes Idaho state forecasted sales growth by customer class.

Table A.13 – Forecasted Retail Sales Growth in Idaho, post-DSM

Idaho Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2019	708,653	507,405	1,784,522	642,926	2,590	**3,646,095**
2020	699,473	517,175	1,784,139	640,292	2,580	**3,643,660**
2021	695,588	520,131	1,781,940	637,612	2,548	**3,637,819**
2022	697,223	524,387	1,780,536	634,963	2,518	**3,639,627**
2023	699,948	527,991	1,778,654	632,234	2,481	**3,641,308**
2024	706,271	531,511	1,777,222	628,727	2,446	**3,646,179**
2025	706,162	529,386	1,773,991	624,315	2,393	**3,636,249**
2026	709,090	527,395	1,771,600	619,091	2,345	**3,629,521**
2027	710,493	525,432	1,769,234	613,336	2,294	**3,620,789**
2028	710,115	525,478	1,767,661	607,711	2,249	**3,613,214**
Compound Annual Growth Rate						
2019-28	**0.02%**	**0.39%**	**-0.11%**	**-0.62%**	**-1.55%**	**-0.10%**

Wyoming

Table A.14 summarizes Wyoming state forecasted sales growth by customer class.

Table A.14 – Forecasted Retail Sales Growth in Wyoming, post-DSM

Wyoming Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2019	951,251	1,354,914	6,968,294	24,398	11,603	**9,310,460**
2020	914,411	1,358,579	6,873,509	24,277	11,528	**9,182,304**
2021	890,481	1,350,275	6,758,266	24,167	11,347	**9,034,535**
2022	876,329	1,344,207	6,718,156	24,060	11,161	**8,973,913**
2023	865,341	1,336,818	6,740,843	23,962	10,940	**8,977,905**
2024	859,738	1,330,275	6,790,086	23,814	10,724	**9,014,636**
2025	844,820	1,308,045	6,743,444	23,601	10,416	**8,930,325**
2026	834,596	1,287,030	6,743,137	23,352	10,123	**8,898,239**
2027	823,992	1,269,711	6,779,811	23,106	9,818	**8,906,437**
2028	814,676	1,259,257	6,763,239	22,872	9,532	**8,869,576**
Compound Annual Growth Rate						
2019-28	**-1.71%**	**-0.81%**	**-0.33%**	**-0.72%**	**-2.16%**	**-0.54%**

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 higher than normal temperatures.

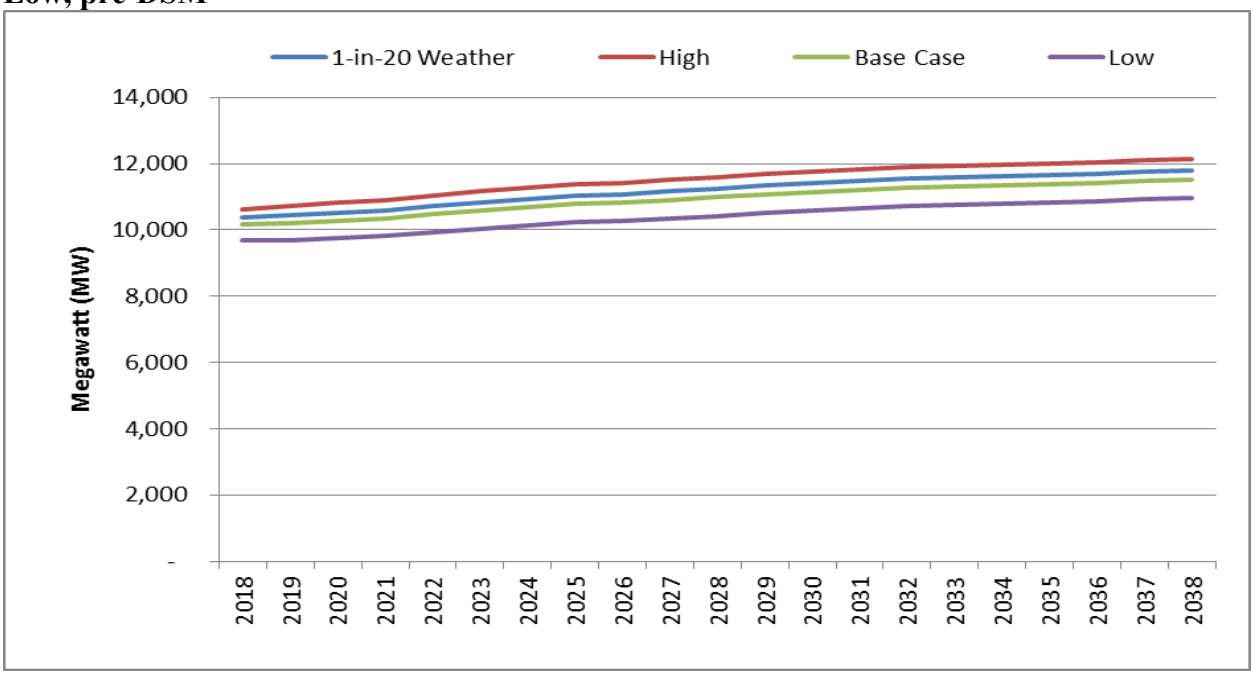
The September 2018 forecast is the baseline scenario. For the high and low load growth scenarios, optimistic and pessimistic economic driver assumptions from IHS Markit were applied to the economic drivers in PacifiCorp's load forecasting models. These growth assumptions were extended for the entire 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 percent prediction interval around the base IRP forecast.

The 95 percent 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 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 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, PacifiCorp 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.

Figure A.11 shows the comparison of the above scenarios relative to the base case scenario.

Figure A.11 – Load Forecast Scenarios for 1-in-20 Weather, High, Base Case and Low, pre-DSM



APPENDIX B - IRP REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2019 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 2017 Integrated Resource Plan (2017 IRP) 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.[1]
- Table B.2 - Provides a description of how PacifiCorp addressed the 2017 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 guidelines issued in January 2006.
- 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 also serves to inform all parties on the planning issues and approach. The public input process for this IRP, described in Volume I, Chapter 2 (Introduction), as well as Volume II, Appendix C (Public Input Process) fully complies with IRP standards and guidelines.

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

[1] California Public Utilities Code Section 454.5 allows utility with less than 500,000 customers in the state to request an exemption from filing an IRP. However, PacifiCorp files its IRP and IRP supplements with the California Public Utilities Commission to address the company plan for compliance with the California RPS requirements.

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 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (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 7 (Modeling and Portfolio Evaluation Approach).

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 8 (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 9 (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 2017 IRP and 2017 IRP Update.

The 2019 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.

On August 1, 2018, PacifiCorp resubmitted its 2017 IRP in compliance with D.18-02-018, and the CPUC approved PacifiCorp's resubmission in D.19-04-040 and deemed it to be in compliance.

On September 20, 2019 the CPUC issued a ruling in Docket R.16.02.007 setting forth proposed IRP filing requirements; CPUC Staff continues to recommend a nonstandard IRP filing plan for multi-jurisdictional utilities, including PacifiCorp. The company submitted comments in support of these filing requirements on October 14, 2019.

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) 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 2019, 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[2]). Consistent with the earlier guidelines (Order 89-507), 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.3 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

2 Public Utility Commission of Oregon, Order No. 12-013, Docket No. 1461, January 19, 2012.

and Order on Standards and Guidelines"). Table B.4 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 least cost planning (Washington Administrative Code 480-100-238) (as amended, January 2006). In addition to a least cost plan, the rule requires provision of a two-year action plan and a progress report that "relates the new plan to the previously filed plan."

The rule requires PacifiCorp to submit a work plan for informal commission review not later than 12 months prior to the due date of the plan. The work plan is required to lay out the contents of the IRP, the resource assessment method, and timing and extent of public participation. PacifiCorp filed a work plan with the WUTC on March 28, 2018, in Docket UE-180259. Table B.5 provides detail on how this IRP addresses each of the rule requirements.

Wyoming

Wyoming Public Service Commission issued new rules that replaced the previous set of rules on 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.6 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)	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.	File biennially.	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 12 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, and environmental risks, 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.

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 identified risks and uncertainties. • Portfolio analysis shall include fuel transportation and	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis. • Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds. • A cost effectiveness methodology. • An evaluation of the financial, competitive, 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. • A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using	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

	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.		"lowest reasonable cost" criteria. • 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.		

Table B.2 – Handling of 2017 IRP Acknowledgment and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2019 IRP
Idaho		
Case No. PAC-E-17-03, Order No. 34018, p. 14	Expect the company to consider public input meeting process concerns raised in the 2017 IRP as related to the Energy Vision 2020 projects and continue to evaluate all resource options and the best interest of customers when developing the 2019 IRP.	For the 2019 IRP, PacifiCorp expanded the public-input meeting process from seven to 18 public-input meetings and presented its preferred portfolio and draft action plan at the October 3-4, 2019 public-input meeting. See Volume II, Appendix C (Public Input Process).
Case No. PAC-E-17-03, Order No. 34018, p. 14	The company should let its modeling fully assess when a coal plant should be retired, and provide resource portfolios that are least-cost based on modeling, and not assumed coal plan retirement.	Recognizing limitations in modeling regarding endogenous transmission retirements, PacifiCorp conducted comprehensive coal studies as part of its 2019 IRP. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results) and Volume II, Appendix R (Coal Studies) in particular for more information.
Case No. PAC-E-17-03, Order No. 34018, p. 14	Expect the company to continue improving its forecasting methodologies by analyzing a broad and diverse range of measures to avoid disadvantageous or unfair forecasting treatment of certain resources over others, including coal and wind.	See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).
Oregon		
Order No. 14-252, p. 3	Beginning in the third quarter of 2014, PacifiCorp will appear before the Commission to provide quarterly updates on coal plant compliance requirements, legal proceedings, pollution control investments, and other major capital expenditures on its coal plants or transmission projects. PacifiCorp may provide a written report and need not appear if there are no significant changes between the quarterly updates.	Order No. 14-288 modified the requirements, moving the date of the first meeting from the third quarter of 2014 to the fourth quarter of 2014. Order No. 16-071 further streamlined this requirement by requiring the company to continue to provide twice yearly updates on the status of demand-side management (DSM) IRP acquisition goals at public meetings and include in these updates information on future coal plant and transmission investment decisions. Also include information on 111(d) rule compliance analysis; Environmental/coal and transmission expenditures quarterly presentations were made at Commission special public meetings on October 28, 2014 and March 16, 2015. Quarterly presentations via written reports were provided on June 30, 2015 and October 1, 2015. The 2015 fourth quarter presentation was made at the Commission special public meeting on December 17, 2015. A biannual DSM update was provided at the Commission public meetings on March 10, 2015 and December 15, 2015 Biannual presentations for both Environmental/coal and transmission

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2019 IRP
		expenditures/111(d) and DSM were provided on August 30, 2016 and December 20, 2016. Please see Commission website for public meeting history and Docket RE 163 for presentations and written reports provided.
Order No. 14-252, p. 3	In future IRPs, PacifiCorp will provide: • Timelines and key decision points for expected pollution control options and transmission investments; and • Tables detailing major planned expenditures with estimated costs in each year for each plant or transmission project, under different modeled scenarios.	PacifiCorp has included two Regional Haze scenarios in the 2019 IRP. See Volume II, Appendix M (Case Study Fact Sheets) for discussion on specific Regional Haze assumptions. For modeling purposes PacifiCorp has included incremental transmission costs associated with specific resources. See Volume I, Chapter 6 (Resource Options) for discussion of these potential costs. Additional detail is provided on the data discs included with the 2019 IRP filing.
Order No. 14-252, p. 13	In the acknowledgement order the Commission provided the following recommendation: As part of the 2015, 2017, and 2019 IRPs, PacifiCorp will provide an updated version of the screening tool spreadsheet model that was provided to participants in the 2011 (docket LC 52) IRP Update.	The screening tool is no longer used to model competing retirement scenarios. In the 2019 IRP, PacifiCorp conducted comprehensive coal studies. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results) and Volume II, Appendix R (Coal Studies) in particular for more information.
Order No. 14-252, p. 16	In future IRPs, PacifiCorp will provide yearly Demand Response (Class 1) and Energy Efficiency (Class 2) DSM acquisition targets in both GWh and MW for each year in the planning period, by state.	See Volume II, Appendix D (Demand-Side Management Resources) for the breakdown by state and year for both energy and capacity selected for the preferred portfolio.
Order No. 16-071, p. 4	The Commission expects the company to update its Clean Power Plan modeling in its 2015 IRP update or its next IRP (depending on when Oregon's compliance plan is known) to correctly reflect the final rule and Oregon's implementation plan.	PacifiCorp's 2019 IRP notes that the Clean Power Plan rule is stayed and that no implementation plans or compliance measures impacted the 2019 IRP.
Order No. 16-071, p. 5	In addition to the action item 3a irrigation pilot program, the Oregon PUC directs PacifiCorp to design and present additional pilots.	PacifiCorp presented information on potential demand response pilot opportunities at the Oregon PUC's August 16, 2016 public input meeting and explained that the 2017 IRP would inform whether the company would propose additional pilot programs.
Order No. 16-071, Appendix A, p.1 (action item 3b)	Continue to provide twice yearly updates on the status of DSM IRP acquisition goals at public meetings. Include in these updates information on future coal plant and transmission investment decisions, as a streamlined continuation of Order No. 14-288.	PacifiCorp provided updates on the status of DSM acquisition goals to the Oregon PUC on October 5, 2018 and August 5, 2019. PacifiCorp did not conduct a sensitivity on accelerated DSM in the 2019 IRP.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2019 IRP
	Also include information on 111 (d) rule compliance analysis; Provide more risk analysis on portfolios that include accelerated energy efficiency as a resource; Include annual incremental summer and winter peak demand capacity (MW) corresponding to 2015 through 2018 Energy Efficiency (Class 2) DSM annual energy savings targets; For the 2015 IRP Update, provide model run results of the preferred portfolio with base case DSM and with accelerated DSM for comparison purposes; Perform stochastic modeling on all portfolios with accelerated DSM.	See Volume I, Chapter 8 (Modeling Portfolio Selection Results) for the annual summer and winter peak demand capacity (MW) for Energy Efficiency DSM.
Order No. 16-071, Appendix A, p.2 (action item 5a) and Order No. 16-071, p. 9.	Continue permitting Energy Gateway Segments D, E, F, and H until PacifiCorp files its 2017 IRP. The Oregon PUC acknowledges this action item only to the extent of PacifiCorp's permitting actions. The Oregon PUC expects to see updated analysis in the next IRP or before the company makes significant commitments to these transmission lines.	See Chapter 4 (Transmission), Chapter 7 (Modeling and Portfolio Evaluation Approach), Chapter 8 (Modeling and Portfolio Selection Results), and Chapter 9 (Action Plan) for updated analysis on the company's Energy Gateway transmission segments. See also Volume II, Appendix M (Case Fact Sheets Overview) for additional detail regarding the Energy Gateway transmission segments studied in the 2019 IRP.
Order No. 16-071, Appendix A, p.2 (additional actions - modeling)	1. Include more robust analysis regarding the west BAA winter peak load/resource balance and portfolios to meet this peak load; 2. Provide quantitative justification for the planning reserve margin of 13 percent; 3. Utilize the Balancing Authority's Area Control Error (ACE) Limit (BAAL) NERC standard in forthcoming wind integration studies, and confirm and demonstrate that the study is based on implementation of the BAAL standard; 4. Use the same regional haze assumptions when directly comparing portfolios.	1. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results) including winter and summer peak load and resource tables. 2. See Volume II, Appendix I (Planning Reserve Margin Study). The study concludes with a planning criteria that meets one day in 10 year planning targets at the lowest reasonable cost. 3. The company's Flexible Reserve Study (Appendix H) incorporates the specific requirements of the BAAL standard (BAL-001-2). 4. Regional haze compliance is embedded in the portfolio-development process. Top performing portfolios reflected in PacifiCorp's 2019 IRP reflect consistent regional haze compliance requirements.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2019 IRP
Order No. 18-138, Appendix A p. 19	PacifiCorp must: 1. Provide an updated economic analysis with the request for acknowledgement of the final shortlist from the 2017R RFP 2. Update its analysis of the Energy Vision 2020 projects as part of its 2017 IRP Update, including any changes resulting from the 2017R RFP or changes to critical assumptions, such as availability of tax credits corporate tax rate, then-current cost-and-performance data for repowered wind resources, cost-and-performance data from the 2017R RFP final shortlist, and cost assumptions for the transmission projects; and 3. Provide quarterly updates to the Oregon PUC and Staff as development of the projects chosen in the 2017R RFP and the transmission projects proceed (through the date the projects go into service).	1. RFP information was provided in the 2017 IRP Update, Chapter 7 (Energy Vision 2020 Update). 2. An update on Energy Vision 2020 was provided in the 2017 IRP Update, Chapter 7 (Energy Vision 2020 Update). 3. PacifiCorp has provided quarterly updates in Docket No. LC-70 starting July 11, 2018. Subsequent updates were provided on October 30, 2018, January 7, 2019, May 7, 2019 and August 2, 2019.
Order No. 18-138, Appendix A p. 20	PacifiCorp must provide the Dave Johnston early retirement transmission analysis to the Oregon PUC and parties in LC 67 once the third-party review and validation has been finalized.	See 2017 IRP Update Filing, Chapter 6 (Portfolio Development).
Order No. 18-138, Appendix A p. 20	1. PacifiCorp is to report back in its 2017 IRP Update as to the current and forecasted use of front office transactions through 2036 and any changes in assumptions impacting front office transaction use from the initial filing of LC 67 in April 2017. 2. PacifiCorp should repeat its study of trading hub liquidity and also the market reliance risk analysis of front office transactions prior to the 2019 IRP. 3. For the 2019 IRP, if a generating resource is included in the preferred portfolio with an associated action item, then PacifiCorp will report on the cost and risk tradeoffs between the preferred portfolio and alternatives that do not include a generating resource.	1. See 2017 IRP Update Filing, Chapter 5 (Modeling and Assumptions Update). 2. See 2019 IRP, Volume II, Appendix J (Western Resource Adequacy Evaluation) for an updated study. 3. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
Order No. 18-138, Appendix A p. 21 as modified by Order No. 18-420	1. PacifiCorp, in coordination with staff and the Energy Trust of Oregon (ETO) will conduct an analysis before the 2019 IRP that identifies and	1. PacifiCorp conducted an analysis in cooperation with Navigant and the Energy Trust of Oregon as part of the 2019 IRP analysis. The report with recommendations was presented at public-input

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2019 IRP
	compares the ongoing differences between ETO and PacifiCorp's near to long-term energy efficiency forecast with ETO's actual achieved savings. PacifiCorp will report on this analysis, including any recommendations to both organizations regarding forecast improvements, in the 2019 IRP. PacifiCorp will present the analysis as a public input IRP meeting. 2. Early in the public input process for the 2019 IRP, prior to finalizing energy efficiency supply curves, PacifiCorp will hold a DSM technical workshop to review and receive input regarding how the company models energy efficiency potential in the IRP and supporting studies such as the Conservation Potential Assessment.	meetings (see below) and is available on PacifiCorp's website. 2. PacifiCorp provided demand-side management workshops as part of its 2019 IRP public-input meetings on June 28-29, 2018 and July 12, 2019.
Order No. 18-138, Appendix A p. 21	PacifiCorp will perform 25 system optimizer (SO) runs, one for each coal unit and a base case. PacifiCorp will summarize the results providing a table of the difference in the PVRR resulting from the early retirement of each unit, an itemized list of coal unit retirement cost assumptions used in each SO run, and a list of coal units that would free up transmission along the path from the proposed Wyoming wind projects if retired. PacifiCorp is to provide this information by June 30, 2018. If there is a dispute about modeling in the meantime, PacifiCorp, staff and parties should first attempt to resolve it informally, but if that fails, staff may report back to the Oregon PUC at a public meeting before the 2019 IRP is filed. An Oregon PUC commissioner workshop will likely be scheduled to review this analysis once it is complete.	PacifiCorp provided the requested information in a public-input meeting presentation on June 28-29, 2018, and the presentation is available on the company's website. PacifiCorp presented an update on its coal studies at a special meeting at the Oregon PUC on December 18, 2018.
Order No. 18-138, Appendix A p. 21	PacifiCorp will continue to model the assumption that EPA regional haze litigation against the company is successful and that PacifiCorp will be required to comply with the current requirements of the State Implementation Plan (SIP) and Federal Implementation Plan (FIP).	PacifiCorp has included two Regional Haze scenarios in the 2019 IRP. See Volume II, Appendix M (Case Study Fact Sheets) for discussion on specific Regional Haze assumptions.
Order No. 18-138, Appendix A p. 21	In the IRP Update PacifiCorp will explain the reasons for the (sometimes) low correlation in the short-term forecast.	See 2017 IRP Update Filing, Chapter 5 (Modeling and Assumptions Update).

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2019 IRP
Order No. 18-138, Appendix A p. 22	In the IRP Update PacifiCorp will model natural gas and storage for meeting flexible reserve study needs.	See 2017 IRP Update Filing, Chapter 5 (Modeling and Assumptions Update).
Order No. 18-138, Appendix A p. 22	PacifiCorp will work with staff and parties to advance distributed energy resource forecasting and representation in the IRP, and define a proposal for opening a distribution system planning investigation.	In the 2019 IRP, PacifiCorp discussed distributed energy resources at its July 26-27, 2019 public-input meeting along with a workshop specific to energy storage.
Order No. 18-138, Appendix A p. 22	PacifiCorp will work with staff and parties to explore the use of AMI data in future IRPs.	AMI data will further enhance the granularity of load forecasting and PacifiCorp will continue to evolve in its IRP process as more AMI data becomes available.
Order No. 18-138, Appendix A p. 22	PacifiCorp, staff and parties should discuss a potential study of the capacity value of renewing QFs, and staff shall bring this issue to a public meeting before the 2017 IRP Update.	PacifiCorp discussed with Staff and parties over conference call and agreed to evaluate its 2019 IRP preferred portfolio load and resource balance with the assumption of QF renewal and provide that information subsequent to the filing of the 2019 IRP.
Utah		
Order, Docket No. 15-035-04, p.18	If PacifiCorp plans to use the System Benefit Tool type of transmission analytical tool in future IRPs, PacifiCorp should introduce and vet the tool in an IRP workshop setting prior to utilizing the tool.	The System Benefit Tool is not used in the 2019 IRP.
Order, Docket No. 15-035-04, p.19	Encourage PacifiCorp in future IRP processes, to provide a stronger demonstration of the reasonableness of the range of renewable resource costs analyzed.	PacifiCorp discussed its 2019 IRP supply-side resource table and inputs at the October 9, 2018 public-input meeting. The supply-side resource table was updated based on stakeholder feedback.
Order, Docket No. 15-035-04, p.20	Direct PacifiCorp to identify the amount of distributed generation in the baseload forecast in its load and resource table, as it does for existing DSM and curtailment.	See Volume I, Chapter 5 (Load and Resource Balance), which breaks out private generation in the same manner as DSM and interruptible load curtailment.
Order, Docket No. 15-035-04, p.21	Direct PacifiCorp to continue to evaluate the depth of the western wholesale market, and to use sensitivity cases and acquisition path analysis, including development of a contingency plan, to monitor the feasibility of long-term reliance on Front Office Transactions to meet near-term load growth.	See Volume II, Appendix J (Western Resource Adequacy Evaluation) for an evaluation of market depth, and also cases studied to assess impacts of higher market prices provided in Volume I, Chapter 8 (Modeling and Portfolio Selection Results). Also refer to acquisition path analysis for contingencies in Volume I, Chapter 9 (Action Plan).
Order, Docket No. 15-035-04, p.21	Recommend continued analysis of the planning reserve margin in future IRPs using results from both loss of load probability studies and analysis of the tradeoffs between reliability and cost.	See Volume II, Appendix I (Planning Reserve Margin Study). The study concludes with a planning criteria that meets one day in 10 year planning targets at the lowest reasonable cost.

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2019 IRP
Order, Docket No. 15-035-04, p.25	Analysis behind Near-Term and Long-Term Resource Acquisition Paths (Table 9.3 in the 2015 IRP) could be improved in terms of identifying potential exogenous changes that would cause a significant change in acquisition path. Encourage PacifiCorp in future IRPs to further define the critical contingencies it is monitoring and identify the magnitude of changes that would be required to potentially trigger movement to any of the different paths listed in the table.	See acquisition path analysis for contingencies in Volume I, Chapter 9 (Action Plan).
Order, Docket No. 15-035-04, p.31	Remind PacifiCorp of the requirement to future IRPs to present the Business Plan as a sensitivity case. If PacifiCorp has substantive objections to this requirement, PacifiCorp should file a motion for Commission action within 90 days of this order explaining the objection and requesting relief.	Please refer to the Sensitivity S-06- presented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results) consistent with the Order in Docket No. 15-035-04.
Order, Docket No. 17-035-16, p.22	Encourage PacifiCorp and stakeholders to review recommendations of the DPU on process at the start of the 2019 IRP process.	PacifiCorp met with Utah stakeholders on August 9, 2018 and discussed recommendations of the Division of Public Utilities (DPU). PacifiCorp made best efforts to implement recommendations for timely materials and also shortened the lunch break and started earlier on the second day of public-input meetings.
Order, Docket No. 17-035-16, p.31	Encourage all parties to communicate in advance of the 2019 IRP about whether a training session on IRP capacity expansion and stochastic models would be appropriate and helpful. There is a distinction between requiring PacifiCorp to create opportunity for public involvement as required by the Guidelines, and requiring PacifiCorp to conduct analyses on behalf of parties.	PacifiCorp held a modeling workshop as part of its June 28-29, 2018 public-input meeting and provided information on its System Optimizer model and Planning and Risk model. PacifiCorp provided details on its models, functionality and planning assumptions throughout the public-input meeting process.
Order, Docket No. 17-035-16, p.35	To satisfy Guideline 3, any changes to the DSM modeling assumptions must be circulated during the IRP development process.	PacifiCorp provided a demand-side management workshop as part of a public-input meeting June 28-29, 2018. An additional workshop was held July 12, 2019. PacifiCorp discussed updates related to demand-side management modeling throughout its 2019 IRP process.
Order, Docket No. 17-035-16, p.37	PacifiCorp commits to conduct a workshop specific to energy storage as part of the 2019 IRP public input process prior to finalizing the supply-side resource table inputs for battery and energy storage.	PacifiCorp held an energy storage workshop August 30, 2018, and the presentation is available on the company's website.
Order, Docket No. 17-035-16, p.43	Expect PacifiCorp and stakeholders to review the DPU's recommendations on transmission modeling at the start of the 2019 IRP process.	PacifiCorp met with Utah stakeholders on August 9, 2018 and discussed recommendations of the Division of Public Utilities (DPU). PacifiCorp provided a transmission overview and update as

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2019 IRP
		part of a public-input meeting September 27-28, 2018.
Washington		
UE-140546, Acknowledgement Letter, p.1	Encourage the company to continue the practice of including data discs with the filing in future IRP filings.	Data discs have provided as part of the 2019 IRP filing.
UE-140546, Acknowledgement Letter, p.2	Encourage the company to continue to evaluate how its method of developing capacity value of renewable resources compares to the effective load carrying capability method on which it was based, to ensure that the company's model is yielding accurate results.	See Volume II, Appendix N (Capacity Contribution Study), analyzing updated hourly profiles and transmission availability impacts to determine effectiveness in meeting system load. The 2019 IRP includes winter peak (in addition to summer peak) in its assumptions, allowing enhanced insight into solar penetration concerns.
UE-140546, Acknowledgement Letter, p.4	The cost impacts in S-10 in the 2015 IRP were on a system basis and the commission would like to see them on a balancing authority area basis. Requests the analysis be redone in the 2017 IRP and that the company use inputs consistent with the staff MSP power flow data or explain why different inputs are more appropriate. Request that the company incorporate the balancing area analysis in all future IRPs.	PacifiCorp plans to incorporate this sensitivity as part of its 2019 IRP Update.
UE-140546, Acknowledgement Letter, p.8	Encourage the company to continue to integrate the EIM into its IRP model, in particular to develop modeling capability to capture how different resources with different generation profiles would interact with the EIM, based on the company's experience with the market.	PacifiCorp incorporated flexible ramping procurement diversity savings from the EIM in its Flexible Reserve Study. See Volume II, Appendix F (Flexible Reserve Study).
UE-160353, Acknowledgement Letter Attachment, p.4-6	Expect examination of Jim Bridger and Colstrip Units 3 & 4 pursuant to specific questions to be addressed in the 2019 IRP.	PacifiCorp plans to incorporate responses to these questions as part of its 2019 IRP Update pursuant to the Washington Utilities and Transportation Commission's July 3, 2019 letter.
UE-160353, Acknowledgement Letter Attachment, p.6-7	Balancing Area analysis in all future IRPs that includes a west control area and an east control area analysis with a robust description of the modeling interaction between the two discrete systems.	See Volume II, Appendix J (Western Resource Adequacy Evaluation).
UE-160353, Acknowledgement Letter Attachment, p.8	Expect the company to incorporate principles in the commission's policy statement on energy storage in the 2019 IRP.	See Volume II, Appendix Q (Energy Storage Potential Evaluation).
UE-160353, Acknowledgement Letter Attachment, p.8-9	Expect the company to provide a market reliance risk assessment in the 2019 IRP and expect the analysis will result in a quantified representation of risk that can be folded into the IRP analytical framework.	See Volume II, Appendix J (Western Resource Adequacy Evaluation). PacifiCorp's 2019 IRP also included analysis of the impact of higher market prices on select cases (FOT cases). See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results).

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2019 IRP
UE-160353, Acknowledgement Letter Attachment, p.9-10	In future IRPs, the company should more prominently display the Quick Reference Guides included in Appendix M of its 2017 IRP.	PacifiCorp expanded Volume II, Appendix M (Case Fact Sheets Overview) to include more portfolio specific materials that were included in public-input meeting presentations throughout the course of the 2019 IRP process. Discussion in Volume I of the 2019 IRP draws more direct references to Volume II, Appendix M (Case Fact Sheets Overview) for simplified navigation.
UE-160353, Acknowledgement Letter Attachment, p.10-11	In future IRPs, the company should incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations in its preferred portfolio. The cost estimate should come from a comprehensive, peer-reviewed estimate of the monetary cost of climate change damages, produced by a reputable organization. WUTC suggests using the Interagency Working Group on Social Cost of Greenhouse Gases estimate with a three percent discount rate. The company should also continue to model other higher and lower cost estimates to understand how the resource portfolio changes based on these costs.	In the 2019 IRP, PacifiCorp assumed a CO_2 price starting in 2025 in its base case analysis. It also performed assessments of certain top performing portfolios under a low gas/no CO_2, a high gas/high CO_2, and a social cost of carbon price-policy scenario that was developed using estimates by the Interagency Working Group on Social Cost of Greenhouse Gases. See Volume I, Chapter 8 (Modeling and Portfolio Selection Results).
UE-160353, Acknowledgement Letter Attachment, p.11	The company should develop a supply curve of emissions abatement and include this cost curve in the 2019 IRP. The analysis should identify all programs and technologies reasonably available in the company's service area, then use best available information to estimate the amount of emissions reductions each option might achieve, and at what cost.	PacifiCorp will use information from this analysis as part of its 2019 IRP Update.
Wyoming		
The Wyoming Public Service Commission accepted Rocky Mountain Power's 2017 Integrated Resource Plan (Docket No. 20000-512-EA-17) without further action on the matter pursuant to action taken at its open meeting on November 20, 2017 and by Letter Order issued January 29, 2019.		

Table B.3 – Oregon Public Utility Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2019 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	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 6 (Resource Options), and Chapter 7 (Modeling and Portfolio Evaluation Approach) document how PacifiCorp developed these resources

No.	Requirement	How the Guideline is Addressed in the 2019 IRP
	demand-side options which focus on conservation and demand response.	and modeled them in its portfolio analysis. All these resources were established as resource options in the company's capacity expansion optimization model, System Optimizer, 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 System Optimizer 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 7 (Modeling and Portfolio Evaluation Approach), Chapter 8 (Modeling and Portfolio Selection Results), and Volume II, Appendix K (Capacity Expansion Results Detail) and Appendix L (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 5 (Load and Resource Balance), Chapter 6 (Resource Alternatives), and Chapter 7 (Modeling and Portfolio Evaluation Approach) as well as Volume II, Appendix D (Demand-Side Management Resources).
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 6.92 percent to discount all cost streams.
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 Monte Carlo production cost simulation with the exception of CO_2 emission compliance costs, which are treated as a scenario risk and evaluated as part of a CO_2 price assumption and a no CO_2, a high CO_2, and a social cost of carbon price-policy scenario for specific studies. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Volume I, Chapter 8 (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 9 (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 (The

No.	Requirement	How the Guideline is Addressed in the 2019 IRP
		Planning Environment), Chapter 4 (Transmission), Chapter 7 (Modeling and Portfolio Evaluation Approach), and Chapter 8 (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 8 (Modeling and Portfolio Selection Results), Chapter 9 (Action Plan), and Volume II, Appendix K (Capacity Expansion Results Detail) 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 (2019-2038) 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 7 (Modeling and Portfolio Evaluation Approach) provides a description of the PVRR methodology.
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 (mean of highest three Monte Carlo iterations) 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 9 (Action Plan).
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Volume I, Chapter 8 (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 Approach) 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 (The Planning Environment). Volume I, Chapter 8 (Modeling and Portfolio Selection Results) provides the results. Volume I,

No.	Requirement	How the Guideline is Addressed in the 2019 IRP
		Chapter 9 (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 I, Chapter 2 (Introduction) provides an overview of the public process, all public-input meetings held for the 2019 IRP, which are documented in Volume II, Appendix C (Public Input Process). PacifiCorp also made use of a Stakeholder Feedback Form for stakeholders to provide comments and offer suggestions. Stakeholder Feedback Forms along with the public-input meeting presentations are available on PacifiCorp's webpage at: www.pacificorp.com/energy/integrated-resource-plan.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.	2019 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 protective order 18-216.
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 2019 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 2019 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 2019 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 subsequent to filing this IRP.

No.	Requirement	How the Guideline is Addressed in the 2019 IRP
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	This activity will be conducted subsequent to filing 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 subsequent to filing this 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 subsequent to filing 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 subsequent to filing this IRP.
Guideline 4. Plan Components: At a minimum, the plan must include the following elements		
4.a	An explanation of how the utility met each of the substantive and procedural requirements.	The purpose 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 System Optimizer model. Stochastic variability of loads was also captured in the risk analysis. See Volume I, Chapters 5 (Load and Resource Balance) and Chapter 7 (Modeling and Portfolio Evaluation Approach), and Volume II, Appendix A (Load Forecast Detail) for load forecast information.

No.	Requirement	How the Guideline is Addressed in the 2019 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 5 (Resource Needs Assessment) 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 7 (Modeling and Portfolio Evaluation Approach).
4.d	For gas utilities only.	Not applicable.
4.e	Identification and estimated costs of all supply-side and demand side resource options, taking into account anticipated advances in technology.	Volume I, Chapter 6 (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 see footnote 3 of this Appendix B.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	In addition to incorporating a 13 percent planning reserve margin for all portfolios evaluated, as supported by an updated Stochastic Loss of Load Study in Volume II, Appendix L (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 7 (Modeling and Portfolio Evaluation Approach).
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered.	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) describes the key assumptions and alternative scenarios used in this IRP. Volume II, Appendix M (Case Study Fact Sheets) includes summaries of assumptions used for each case definition analyzed in the 2019 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 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (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 8 (Modeling and Portfolio Selection Results) presents the stochastic portfolio modeling results, 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 8 (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 2019 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 9 (Action Plan) presents the 2019 IRP action plan.
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.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	A multi-state demand-side management potential study was completed in 2018, and those results were incorporated into this plan.
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 6 (Resource Options), the results in Volume I, Chapter 8 (Modeling and Portfolio Selection Results), the targeted amounts in Volume I, Chapter 9 (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.

No.	Requirement	How the Guideline is Addressed in the 2019 IRP
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 (Class 1 DSM) on a consistent basis with other resources.
Guideline 8: Environmental Costs		
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 7 (Modeling and Portfolio Evaluation Approach). In the 2019 IRP, PacifiCorp modeled a price on CO_2 starting in 2025.
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 L (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 7 (Modeling and Portfolio Evaluation Approach) 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.
8.c	Trigger point analysis: The utility should identify at least one CO_2 compliance "turning	See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) for a description of initial

No.	Requirement	How the Guideline is Addressed in the 2019 IRP
	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 CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent that the identified trigger point will be mandated.	portfolio-development definitions. Comparative analysis of these case results is included in Volume I, Chapter 8 (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 8 (Modeling and Portfolio Selection Results).
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 2019 IRP conforms to the multi-state planning approach as stated in Volume I, Chapter 2 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 8 (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.

No.	Requirement	How the Guideline is Addressed in the 2019 IRP
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 Navigant 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 O (Private Generation Study).
Guideline 13: Resource Acquisition		
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.	Chapter 9 (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 9 (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 2019 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.	See 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.	See 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.	See Volume II, Appendix F (Flexible Reserve Study).

Table B.4 – Utah Public Service Commission IRP Standard and Guidelines

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 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.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 IRP
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the 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 Process). 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 7 (Modeling and Portfolio Evaluation Approach) 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 PacifiCorp's capacity expansion optimization model. 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 9 (Action Plan) describes the linkage between the 2019 IRP preferred portfolio and December 2018 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.
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers,	Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) outlines the portfolio performance evaluation and preferred portfolio selection process, while Chapter 8 (Modeling and Portfolio Selection Results) chronicles the modeling and preferred portfolio selection process. This IRP

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 IRP
	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.	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 April 4, 2017, and filed this IRP on October 18, 2019 meeting the requirement. PacifiCorp requested and was granted an extension of time to file the 2019 IRP in Docket No. 19-035-02.
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 is provided in Volume II, Appendix C (Public Input Process).
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 2019 IRP are provided in Volume I, Chapter 5 (Resource Needs Assessment) and Volume II, Appendix A (Load Forecast Details).
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 5 (Resource Needs Assessment) and Volume II, Appendix A (Load Forecast Details). 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 Details) documents how demographic and price factors are used in PacifiCorp's load forecasting methodology.
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 System Optimizer model and Planning and Risk production cost model using both supply side and demand side alternatives. See explanation in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and the results in Volume I, Chapter 8 (Modeling and Portfolio

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 IRP
		Selection Results). Resource options are summarized in Volume I, Chapter 6 (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 (Class 1) DSM (dispatchable/schedulable load control) and Energy Efficiency (Class 2) DSM in its capacity expansion model. Details are provided in Volume I, Chapter 6 (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. Volume I, Chapters 6 (Resource Options) and 7 (Modeling and Portfolio Evaluation Approach) 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. Dispatchability is accounted for in both IRP models used; however, the Planning and Risk model provides a more detailed representation of unit dispatch than System Optimizer, and includes modeling of unit commitment and reserves.
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 9 (Action Plan).
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2019-2038).
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 9 (Action Plan). A status report of the actions outlined in the previous action plan (2017 IRP Update) is provided in Volume I, Chapter 9 (Action Plan). In Volume I, Chapter 9 (Action Plan) Table 9.1 identifies actions anticipated in the next two years and in the next four years.
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 9 (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.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 IRP
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 6 (Resource Options). The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: ● Top performing 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 (The 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 8 (Modeling and Portfolio Selection Results). ● Volume II, Appendix G (Plant Water Consumption) reports historical water consumption for PacifiCorp's thermal plants.
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 9 (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 Chapter 4 (Transmission). Resource capital cost uncertainty and technological risk is addressed in Volume I, Chapter 6 (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 9 (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 9 (Action Plan), specifically, Table 9.1.
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 8 (Modeling and Portfolio Selection Results).
4.k	A range, rather than attempts at precise quantification, of estimated external costs which	PacifiCorp incorporated environmental externality costs for CO_2 and costs for complying with current

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 IRP
	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.	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 7 (Modeling and Portfolio Evaluation Approach).
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 (The 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 6 (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 2019 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 2019 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 2019 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 2019 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.
7	Acknowledgment of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 IRP
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.

Table B.5 – Washington Utilities and Transportation Commission IRP Standard and Guidelines (RCW 19.280.030 and WAC 480-100-238)

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 IRP
Requirements prior to IRP Filing		
(4)	Work plan filed no later than 12 months before next IRP due date.	PacifiCorp filed the 2019 IRP work plan on July 17, 2019 in Docket No. UE-180259, given an anticipated IRP filing date of October 18, 2019. PacifiCorp was granted approval in Docket No. UE-180259 on July 26, 2019 to file the IRP October 18, 2019.
(4)	Work plan outlines content of IRP.	See pages 1-2 of the Work Plan document for a summarization of anticipated IRP contents.
(4)	Work plan outlines method for assessing potential resources. (See LRC analysis below)	See pages 3-5 of the Work Plan document for a summarization of anticipated resource analysis.
(5)	Work plan outlines timing and extent of public participation.	See pages 5-6 of the Work Plan. Table 1, page 6, document for the anticipated IRP schedule. PacifiCorp was granted approval in Docket No. UE-180259 on July 26, 2019 to file the 2019 IRP on October 18, 2019.
(4)	Integrated resource plan submitted within two years of previous plan.	The WUTC issued an Order on December 11, 2008, under Docket No. UE-070117, granting the company permission to file its IRP on March 31 of each odd numbered year. PacifiCorp filed the 2017 IRP on April 4, 2017. PacifiCorp was granted approval in Docket No. UE-180259 on July 26, 2019 to file the IRP October 18, 2019.
(5)	WUTC issues notice of public hearing after company files plan for review.	This obligation is not applicable to the company; this is a WUTC obligation.
(5)	WUTC holds public hearing.	This obligation is not applicable to the company; this is a WUTC obligation.
Requirements specific to IRP filing		
(2)(a)	Plan describes the mix of energy supply resources.	Volume I, Chapter 5 (Resource Needs Assessment) describes the mix of existing resources, while Volume I, Chapter 8 (Modeling and Portfolio Selection Results) describes the 2019 IRP preferred portfolio.
(2)(a)	Plan describes conservation supply.	See Volume I, Chapter 6 (Resource Options) for a description of how conservation supplies are represented and modeled, and Volume I, Chapter 8 (Modeling and Portfolio Selection Results) for conservation supply in the preferred portfolio. Additional information on energy efficiency resource characteristics is available on PacifiCorp's IRP website.
(2)(a)	Plan addresses supply in terms of current and future needs at the lowest reasonable cost to the utility and its ratepayers.	The 2019 IRP preferred portfolio was based on a resource needs assessment that accounted for forecasted load growth, expiration of existing power purchase contracts, resources under construction, contract, or reflected in the company's capital budget, as well as a capacity planning reserve margin. Details on PacifiCorp's findings of resource need are described in Volume I, Chapter 5 (Resource Needs Assessment).
(2)(b)	Plan uses lowest reasonable cost (LRC) analysis to select the mix of resources.	PacifiCorp uses portfolio performance measures based on the Present Value of Revenue Requirements (PVRR) methodology. See the section on portfolio performance measures in Volume I, Chapter

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 IRP
		7 (Modeling and Portfolio Evaluation Approach) and Volume I Chapter 8 (Modeling and Portfolio Selection Results).
(2)(b)	LRC analysis considers resource costs.	Volume I, Chapter 6 (Resource Options), provides detailed information on costs and other attributes for all resources analyzed for the IRP.
(2)(b)	LRC analysis considers market-volatility risks.	PacifiCorp employs Monte Carlo production cost simulation with a stochastic model to characterize market price and gas price volatility. Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) provides a summary of the modeling approach.
(2)(b)	LRC analysis considers demand side resource uncertainties.	PacifiCorp captured demand-side resource uncertainties through the development of numerous portfolios based on different sets of input assumptions.
(2)(b)	LRC analysis considers resource dispatchability.	PacifiCorp uses two IRP models that simulate the dispatch of existing and future resources based on such attributes as heat rate, availability, fuel cost, and variable O&M cost. The chronological production cost simulation model also incorporates unit commitment logic for handling start-up, shutdown, ramp rates, minimum up/down times, and run up rates, and reserve holding characteristics of individual generators.
(2)(b)	LRC analysis considers resource effect on system operation.	PacifiCorp's IRP models simulate the operation of its entire system, reflecting dispatch/unit commitment, forced/unforced outages, access to markets, and system reliability and transmission constraints.
(2)(b)	LRC analysis considers risks imposed on ratepayers.	PacifiCorp explicitly models risk associated with uncertain CO_2 regulatory regimes, wholesale electricity and natural gas price escalation and volatility, load growth uncertainty, resource reliability, renewable portfolio standard requirement uncertainty, plant construction cost escalation, and resource affordability. These risks and uncertainties are handled through stochastic modeling and scenarios depicting alternative futures. In addition to risk modeling, the IRP discusses a number of resource risk topics not addressed in the IRP system simulation models. For example, Volume I, Chapter 9 (Action Plan) covers the following topics: (1) managing carbon risk for existing plants, (2) assessment of owning vs. purchasing power, (3) purpose of hedging, (4) procurement delays and (5) treatment of customer and investor risks. Volume I, Chapter 4 (Transmission) covers similar risks associated with transmission system expansion.
(2)(b)	LRC analysis considers public policies regarding resource preference adopted by Washington state or federal government.	In Volume I, Chapter 7 (Modeling and Portfolio Evaluation) the IRP modeling incorporates resource expansion constraints tied to renewable portfolio standards (RPS) currently in place for Washington. I-937 conservation requirements are explicitly accounted for in developing Washington conservation resource costs.
(2)(b)	LRC analysis considers cost of risks associated with environmental effects including emissions of carbon dioxide.	See (2)(b) above.
(2)(c)	Plan defines conservation as any reduction in electric power consumption that results from increases in the efficiency of energy use, production, or distribution.	A description of how PacifiCorp classifies and defines energy conservation is provided in Volume I, Chapter 6 (Resource Options).

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 IRP
(3)(a)	Plan includes a range of forecasts of future demand.	PacifiCorp implemented a load forecast range. Details concerning the load forecasts used in the 2017 IRP (high, low, and extreme peak temperature) are provided in Volume II, Appendix A (Load Forecast Details).
(3)(a)	Plan develops forecasts using methods that examine the effect of economic forces on the consumption of electricity.	PacifiCorp's load forecast methodology employs econometric forecasting techniques that include such economic variables as household income, employment, and population. See Volume II, Appendix A (Load Forecast Details) for a description of the load forecasting methodology.
(3)(a)	Plan develops forecasts using methods that address changes in the number, type and efficiency of electrical end-uses.	Residential sector load forecasts use a statistically-adjusted end-use model that accounts for equipment saturation rates and efficiency. See Volume II, Appendix A (Load Forecast Details), for a description of the residential sector load forecasting methodology.
(3)(b)	Plan includes an assessment of commercially available conservation, including load management.	PacifiCorp updated the system-wide demand-side management potential study in the 2019 IRP, which served as the basis for developing DSM resource supply curves for resource portfolio modeling. The supply curves account for technical and achievable (market) potential, while the IRP capacity expansion model identifies a cost-effective mix of DSM resources based on these limits and other model inputs. The DSM potential study is included on the data disc, and available on PacifiCorp's IRP website at: www.pacificorp.com/energy/integrated-resource-plan/support.html.
(3)(b)	Plan includes an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	A description of the current status of DSM programs and on-going activities to implement current and new programs is provided in Volume I, Chapter 5 (Resource Needs Assessment).
(3)(c)	Plan includes an assessment of a wide range of conventional and commercially available nonconventional generating technologies.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), customer standby generation, power purchases, thermal resources, energy storage, and transmission. Volume I, Chapters 6 (Resource Options) and Chapter 7 (Modeling and Portfolio Evaluation Approach) document how PacifiCorp developed and assessed these technologies.
(3)(d)	Plan includes an assessment of transmission system capability and reliability; to the extent such information can be provided consistent with applicable laws.	PacifiCorp modeled transmission system capability to serve its load obligations, factoring in updates to the representation of major load and generation centers, regional transmission congestion impacts, import/export availability, external market dynamics, and significant transmission expansion plans explained in Volume I, Chapter 4 (Transmission) and Chapter 7 (Modeling and Portfolio Evaluation Approach). System reliability given transmission capability was analyzed using stochastic production cost simulation and measures of insufficient energy and capacity for a load area (Energy Not Served and Unmet Capacity, respectively).
(3)(e)	Plan includes a comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using LRC.	PacifiCorp's capacity expansion optimization model (System Optimizer) is designed to compare alternative resources—including transmission expansion options—for the least-cost resource mix. System Optimizer was used to develop numerous resource portfolios for comparative evaluation on the basis of cost, risk, reliability, and other performance attributes. Potential energy savings associated with conservation voltage reduction are discussed in Volume I, Chapter 5 (Resource Needs Assessment).
(3)(f)	Plan includes integration of the demand forecasts and resource evaluations into a long range integrated resource plan describing	PacifiCorp integrates demand forecasts, resources, and system operations in the context of a system modeling framework described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). The portfolio evaluation covers a 20-year period (2019-

No.	Requirement	How the Standards and Guidelines are Addressed in the 2019 IRP
	the mix of resources that is designated to meet current and project future needs at the lowest reasonable cost to the utility and its ratepayers.	2038). PacifiCorp developed its preferred portfolio of resources judged to be least-cost after considering load requirements, risk, uncertainty, supply adequacy/reliability, and government resource policies in accordance with this rule.
(3)(g)	Plan includes a two-year action plan that implements the long range plan.	See Table 9.1 in Volume I, Chapter 9 (Action Plan), for PacifiCorp's 2019 IRP action plan.
(3)(h)	Plan includes a progress report on the implementation of the previously filed plan.	See Table 9.2 for a status report on action plan implementation from the 2017 IRP and 2017 IRP Update in Volume I, Chapter 9 (Action Plan).
Requirements from RCW 19.280.030 not discussed above		
(1)(e)	An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio;	See Volume I, Chapter 6 (Resource Options) for discussion of resource options in the 2019 IRP. Also see Volume II, Appendix P (Renewable Resources Assessment).
(1)(f)	The integration of the demand forecasts and resource evaluations into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events, at the lowest reasonable cost and risk to the utility and its ratepayers;	See Volume II, Appendix A (Load Forecast Details) for a discussion of the load forecasts, supply-side and demand-side resources are discussed in Volume I, Chapter 6 (Resource Options). Also included is a discussion of DSM in Volume II, Appendix D (DSM Resources) are included in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results) discuss the modeling methodology and selection of the preferred portfolio using least cost/least risk metrics.

Table B.6 – Wyoming Public Service Commission Guidelines Regarding Electric IRP

No.	Requirement	How the Guideline is Addressed in the 2019 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 Process).
B	The utility's strategic goals and resource planning goals and preferred resource portfolio;	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) documents the preferred resource portfolio and rationale for selection. Volume I, Chapter 9 (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 5 (Resource Needs Assessment).
D	A study detailing the types of resources considered;	Volume, I Chapter 6 (Resource Options), presents the resource options used for resource portfolio modeling for this IRP.
F	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 2017 IRP Update is presented in Volume I, Chapter 9 (Action Plan). A chart comparing the peak load forecasts for the 2017 IRP, 2017 IRP Update, and 2019 IRP is included in Volume II, Appendix A (Load Forecast Details).
G	The environmental impacts considered;	Portfolio comparisons for CO_2 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 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio

No.	Requirement	How the Guideline is Addressed in the 2019 IRP
		Selection) as well as Volume II, Appendix L (Stochastic Simulation Results).
H	Market purchases evaluation;	Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in the 2019 IRP.
I	Reserve Margin analysis; and	PacifiCorp's planning reserve margin study, which documents selection of a capacity planning reserve margin is in Volume I, Appendix I (Planning Reserve Margin Study).
J	Demand-side management and conservation options;	See Volume I, Chapter 6 (Resource Options) 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.

Stakeholders have been involved in the development of the 2019 IRP from the beginning. The public-input meetings held beginning in June 2018 were the cornerstone of the direct public-input process. There were a total of 18 public-input meetings, with eight lasting two days, the remainder being single days. Meetings were held jointly in both Salt Lake City, Utah and Portland, Oregon via video conference, with expanded video conference locations in Denver, Colorado and Cheyenne, Wyoming. Three meetings were held via phone conference. For all meetings, attendees off-site were able to conference in via phone.

The IRP public-input process also included state-specific stakeholder dialogue sessions held in June and August of 2018. The goal of these sessions was to capture key IRP issues of most concern to each state, as well as discuss how to tackle these 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 housed feedback form discussed earlier in Chapter 2 - Introduction. This standardized form allowed stakeholders opportunities to provide comments, questions, and suggestions. PacifiCorp also posted its response to the feedback forms at the same location. Feedback forms and PacifiCorp's responses can be found via the following link: (www.pacificorp.com/energy/integrated-resource-plan/comments.html).

Participant List

PacifiCorp's 2019 IRP was a robust process involving input from many parties throughout. Organizations actively participated in the development of material, modeling process, and public meetings. Participants included commissions, stakeholders, and industry experts. Among the organizations that were represented and actively involved in this collaborative effort were:

Commissions

- Idaho Public Utilities Commission
- Oregon Public Utilities Commission
- Public Service Commission of Utah
- Washington Utilities and Transportation Commission

- Wyoming Public Service Commission

Stakeholders and Industry Experts

- Alliance of Western Energy Consumers
- Applied Energy Group
- Avangrid
- Black & Veatch
- Breathe Utah
- Burns & McDonnell Engineering Company
- Cascade Natural Gas
- City of Kemmerer Wyoming
- Clarke Investments, LLC
- Enel Green Power
- Energy Trust of Oregon
- First Solar
- Gardner Energy
- Glenrock Energy
- Heal Utah
- Holladay United Church of Christ
- Idaho Conservation League
- Idaho Power Company
- Idaho Public Utility Commission Staff
- Individual Customers
- Industrial Customers of Northwest Utilities
- Intermountain Wind
- Lincoln County Commission
- Magnum Development
- National Grid Ventures
- Natural Resources Defense Council
- Navigant Consulting, Inc.
- Northwest Pipeline GP
- Oregon Department of Energy
- Oregon Department of Justice
- Oregon Public Utility Commission Staff
- Portland General Electric
- Power Quip
- Renewables Northwest
- Sierra Club
- Utah Clean Energy
- Utah Division of Public Utilities
- Utah Office of Consumer Services
- Utah Office of Energy Development
- Washington Office of Attorney General, Public Council Unit
- Western Resource Advocates
- Westmoreland

- Wyoming Coalition of Local Governments & Lincoln County
- Wyoming Department of Workforce Services
- Wyoming House District 18
- Wyoming Infrastructure Authority
- Wyoming Liberty Group
- Wyoming Office Of Consumer Advocate

PacifiCorp extends its gratitude for the time and energy participants have given to the IRP process. Their participation has contributed significantly to the quality of this plan and their continued participation will help PacifiCorp as it strives to improve its planning efforts going forward.

Public-Input Meetings

As mentioned above, PacifiCorp hosted 18 public-input meetings, as well as six state meetings during the public-input process. During the 2019 IRP public-input process presentations and discussions covered various issues regarding inputs, assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public-input meetings; the presentations cab be located at: www.pacificorp.com/energy/integrated-resource-plan.html.

General Meetings

June 28-29, 2018 – General Public Meeting

Day One (Confidential Discussion)
- Introductions
- Model Overview (System Optimizer / Planning and Risk)
- Unit-by-Unit Coal Study Results

Day Two (Public Discussion)
- 2017 IRP Update Highlights / 2019 IRP Topics and Timeline
- Demand-Side Management Workshop

July 26-27, 2018 – General Public Meeting

Day One
- Energy Storage Workshop
- Renewable Resource Schedules and Load Forecast
- Distribution System Planning
- Supply-Side Resource Study Efforts

Day Two
- Environmental Policy
- Renewable Portfolio Standards
- 2019 IRP Modeling Assumptions and Study Updates
    - Intra-Hour Dispatch Credit
    - Stochastic Parameters Update
    - Overview of Planning Reserve Margin and Capacity Contribution Studies

August 30-31, 2018 – General Public Meeting

Day One

- Private Generation Study
- Conservation Potential Assessment and Energy Efficiency Credits
- Portfolio Development Process / Initial Sensitivity Studies
- Flexible Reserve Study
- Process Improvement / Next Steps

Day 2

- Market Reliance Assessment
- Planning Reserve Margin Study / Capacity Contribution Study

September 26-27, 2018 – General Public Meeting

Day One

- Draft Supply-Side Resource Table
- Intra-Hour Flexible Resource Credit
- Environmental Policy / Price-Policy Scenarios
- Transmission Overview and Updates
- Stakeholder Feedback Form Recap

Day Two

- Flexible Reserve Study Cost Results
- Planning Reserve Margin / Capacity Contribution Results
- Portfolios Discussion / Coal Studies Next Steps
- Demand-Side Management Transmission and Distribution Credit / Conservation Potential Assessment

October 9, 2018 – General Public Meeting (Conference Call Only)

- Supply-Side Resource Table Levelized Costs
- Intra-Hour Flexible Resource Credits
- Updated CO_2 Assumption

November 1, 2018 – General Public Meeting

- Supply-Side Resource Table
- Modeling Improvements and Updates
- Update on Coal Analysis
- Stakeholder Feedback Form Recap

December 3-4, 2018 – General Public Meeting

Day One

- Coal Studies Discussion

Day Two

- Coal Studies Discussion (continued)
- Stakeholder Feedback Form Recap

January 24, 2019 – General Public Meeting

- Capacity-Contribution Values for Energy-Limited Resources
- Coal Studies Discussion
- Stakeholder Feedback Form Recap

February 21, 2019 – General Public Meeting (Conference Call Only)

- General Updates
- Summary of Oregon Energy Efficiency Analysis Results
- Stakeholder Feedback Form Recap

March 21, 2019 – General Public Meeting

- Coal Studies Modeling Improvements and Updates
- Modeling Next Steps
- Stakeholder Feedback Form Recap

April 25, 2019 – General Public Meeting

- Coal Studies Discussion
- Stakeholder Feedback Form Recap

May 20-21, 2019 – General Public Meeting

Day One

- Conservation Potential Assessment Cost Correction
- DSM Bundling Portfolio Methodology
- Updated Portfolio Matrix
- Portfolio Analysis Results Discussion

Day Two

- Portfolio Analysis Results Discussion (continued)
- Stakeholder Feedback Form Recap

June 20-21, 2019 – General Public Meeting

Day One

- Modeling Updates
- Portfolio Analysis Results

Day Two

- Portfolio Analysis Results
- Stakeholder Feedback Form Recap

July 12, 2019 – DSM Workshop

- Conservation Potential Assessment
- Demand-Side Management Portfolio Methodology

July 18, 2019 – General Public Meeting (Conference Call Only)

- General Updates
- Stakeholder Feedback Form Recap

September 5, 2019 – General Public Meeting

- Portfolio Analysis Results
- Stakeholder Feedback Form Recap

October 3-4, 2019 – General Public Meeting

Day One

- Preferred Portfolio and Action Plan
- Portfolio Development and Selection

Day Two

- Portfolio Development and Selection
- Sensitivities
- Stakeholder Feedback Form Recap

November 12, 2019 – General Public Meeting (Planned)

- Stakeholder Q&A
- Transmission Modeling Workshop

State-Specific Input Meetings

June 11, 2018 – Oregon State Stakeholder Meeting
June 12, 2018 – Washington State Stakeholder Meeting
June 18, 2018 – Idaho State Stakeholder Meeting
June 19, 2018 – Wyoming State Stakeholder Meeting
June 20, 2018 – Utah State Stakeholder Meeting
August 9, 2018 – Utah State Stakeholder Meeting

Stakeholder Comments

For the 2019 IRP, PacifiCorp offered a Stakeholder Feedback Form which provided stakeholders a direct opportunity to provide comments, questions, and suggestions outside 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.

During the 2019 IRP development process, PacifiCorp received 132 Stakeholder Feedback Forms with a combined 564 questions. The Stakeholder Feedback Form allowed the company to review and summarize issues by topic as well as identify specific recommendations that were provided. Information collected was used to inform the 2019 IRP development process, including feedback related to process improvements and input assumptions, as well as responding directly to stakeholder questions. Stakeholder Feedback Forms were received from the following stakeholders:

- City of Kemmerer, Wyoming
- Energy Strategies, LLC
- First Solar
- Gridflex Energy, LLC

- Idaho Conservation League
- Idaho Public Utility Commission Staff
- Individual Stakeholders
- Interwest Energy Alliance
- Key Capture Energy
- Lawrence Berkeley National Laboratory
- Lincoln County School District
- National Grid Ventures
- Northwest Energy Coalition
- Northwest Power and Conservation Council
- Oregon Citizens' Utility Board
- Oregon Public Utility Commission Staff
- Oyster Ridge BOCES
- Powder River Basin Resource Council
- Renewable Northwest
- Sierra Club
- Sound Geothermal Corporation
- South Lincoln EMS
- South Lincoln Medical Center
- Southwest Energy Efficiency Project
- Utah Association of Energy Users
- Utah Clean Energy
- Washington Utilities and Transportation Commission Staff
- Western Resource Advocates
- Wyoming Business Council
- Wyoming Coalition of Local Governments & Lincoln County
- Wyoming House District 18
- Wyoming Office of Consumer Advocate

Some topics of note addressed in the forms include:

- Capacity Factors
- Coal Analysis
- Coal Combustion Residuals
- Coal Studies
- Conservation Credit
- Conservation Potential Assessment
- Consultant Reports
- Demand Response
- Demand-Side Management
- Demand-Side Management Modeling
- Distribution System Planning
- Energy Efficiency
- Energy Storage
- Environmental Policy
- Flexible Reserve Study

- General Comments
- Inflation Assumption
- Initial Sensitivity Studies
- Intra-hour Dispatch Credits
- IRP Filing Date
- IRP Public-Input Meeting Process
- Legislation
- Levelized Cost Curves
- Load Forecasting
- Market Purchases
- Market Reliance Assessment
- Modeling Assumptions
- Modeling Improvements
- Planning Reserve Margin
- Portfolio Analysis
- Private Generation Study
- Reliability Assessment
- Renewable Energy Resources
- Sensitivity Studies
- Supply-side Resource Costs
- Supply-side Resource Table
- Transmission
- Unit Specific Questions

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

Phone Number:
(503) 813-5245

APPENDIX D – DEMAND-SIDE MANAGEMENT RESOURCES

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 2019 Integrated Resource Plan (IRP). In addition, it provides information on the economic DSM selections in the 2019 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 2019-2038

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 2019-2038,[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 resource acquisition. Study results were incorporated into PacifiCorp's 2019 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 classifications, differentiated by two primary characteristics: reliability and customer choice. These resources classifications can be defined as: demand response (Class 1 DSM) (e.g., a firm, capacity focused resource such as a load control), energy efficiency (Class 2 DSM) (e.g., a firm energy intensity resource such as conservation), Class 3 DSM (e.g., a non-firm, capacity focused such as pricing response or load shifting), and Class 4 DSM (e.g., a behavioral-based resource such as 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, Class 4 DSM 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

[1] PacifiCorp's Demand-Side Resource Potential Assessment for 2017-2036, completed by AEG, can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

to occur over a certain period of time. Class 3 and Class 4 DSM activities involve greater customer choice and control. This assessment estimates potential from demand response, energy efficiency, and Class 3 DSM.

The CPA excludes an assessment of Oregon's energy efficiency resource potential, as this work is performed by the 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 bases. 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 the 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 Class 3 DSM offerings currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), residential seasonal inverted block rates (Idaho and Utah) and residential year-round inverted block rates (California, Oregon, Washington, and Wyoming). System-wide, approximately 17,500 customers were participating in metered time-of-day and time-of-use programs as of December 31, 2017.

All of PacifiCorp's residential customers not opting for Class 3 DSM time-of-use rates are currently subject to seasonal or year-round inverted block rate plans. Savings associated with these resources are captured within the company's load forecast and are thus captured in the integrated resource planning framework. PacifiCorp continues to evaluate Class 3 DSM programs for applicability to long-term resource planning.

PacifiCorp provides Class 4 DSM offerings. 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 Class 4 DSM 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 ***watt***smart 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.htmland 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		√	√		√	
Energy Saving Kits	√	√	√	√	√	√
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						
Air Conditioner Direct Load Control		√		√	√	
Irrigation Load Control		√		√	√	
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		√			√	

Wattsmart Outreach & Communications (incremental to program specific advertising)	California	Oregon	Washington	Idaho	Utah	Wyoming
Social Media	√	√	√	√	√	√
Public Relations	√	√	√		√	√
Business Advocacy (awards at customer meetings, sponsorships, chamber partnership, university partnership)	√	√	√	√	√	√
Wattsmart Workshops and Community Outreach	√	√	√	√	√	√
Be wattsmart, 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.

California
On September 15, 2017, PacifiCorp filed Application 17-09-010 requesting authorization to continue offering its energy efficiency programs (through 2020). The Commission issued Decision 18-11-033 on December 6, 2018, approving the company's application to continue administering its programs through 2020. PacifiCorp expects to submit an application for the continuation of energy efficiency programs beyond 2020.

Oregon
Energy efficiency programs for Oregon customers are planned for and delivered by the Energy Trust of Oregon in collaboration with PacifiCorp. The 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.

APPENDIX E – SMART GRID

Introduction

The smart grid is the application of advanced communications and controls to the electric power system. Areas of installation include generation, transmission, distribution, and customer facilities. A wide array of applications can be defined under the smart grid umbrella. Smart grid includes technologies such as dynamic line rating, phasor measurement units (synchrophasors), energy storage, power line sensors, distribution automation, integrated volt/var optimization, advanced metering infrastructure, automated demand response, and smart renewable and/or distributed generation controls (e.g., smart inverters).

PacifiCorp has reviewed relevant smart grid technologies for transmission, substation, and distribution systems. When considering smart grid technologies, the communications network is often the most critical infrastructure decision. This network must have high speed, reliability, and security. It must be interoperable for many device types, manufacturers, and generations of technology and must be scalable in order to support PacifiCorp's entire service territory.

PacifiCorp regularly evaluates integrating smart grid technologies and implements those that show a positive net benefit for its customers. PacifiCorp has tested or implemented smart grid devices and functions such as dynamic line rating, synchrophasors, and communicating faulted circuit indicators. Advanced metering infrastructure, distribution automation, and distributed energy resource systems (including electric vehicles) are also underway or under consideration.

PacifiCorp will leverage smart grid technologies to align investments with the least-cost/least-risk goals of the Integrated Resource Plan (IRP). 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 and recommend them for demonstration or integration if they are found to be appropriate investments. PacifiCorp 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 is able to improve estimates of the costs and benefits of smart grid technologies. Progressing large-scale deployments and demonstration projects will reveal the effect of large-scale rollouts and assist PacifiCorp in identifying the best suited technologies for implementation.

Transmission System Efforts

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 on line loading calculations given a set of worst-case weather assumptions such as high ambient temperatures and very low wind speeds. Dynamic line rating allows an increase in current-carrying capacity when more favorable weather conditions are present and the

transmission path is not constrained by other operating elements. Two dynamic line rating projects were implemented in 2014, Miners-Platte and West-of-Populus.

The Miners-Platte project uses a dynamic line rating system 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 Miners-Platte 230 kV transmission line was one of the limitations of the TOT4A transmission path with wind farms significantly impacting the loading of the line. As a result of this project, the TOT4A Western Electricity Coordinating Council (WECC) non-simultaneous path rating was increased.

The West-of-Populus project was the second dynamic line rating project in 2014. The dynamic line rating enabled lines experienced low line loading due to peak loads between Pacific Power and Rocky Mountain Power coinciding over time. As a result of this low loading, the thermal reading of the lines is dependent upon ambient weather conditions without being greatly affected by line loading. Until higher line loading is experienced from high flow scenarios or outages, conclusions concerning the dynamic line rating project in West-of-Populus are difficult to ascertain. PacifiCorp will continue to collect and analyze future data as high line loading is experienced.

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. It may or may not align with the expected transmission need of future projects. PacifiCorp will continue to look for opportunities to cost-effectively employ dynamic line rating systems.

Thermal Replicating Relays

PacifiCorp extensively considered a project to install thermal replicating relays to adhere to protection and control compliance standards in the Soda Springs area of Idaho. Thermal replicating relays utilize dynamic line rating to monitor the thermal properties of the line, then send a trip signal if the thermal limit has been exceeded. These relays may only be used where line tripping will not cause cascading outages. A remedial action scheme (RAS) was also analyzed as an alternative to thermal replicating relays for the Soda Springs area. In this particular case, because the remedial action scheme was deemed more cost-effective, the thermal replicating relay project alternative will not be employed.

Synchrophasors

Synchrophasors, also called phasor measurement units, can lead to a more reliable transmission network by comparing phase angles of certain network elements with a base element measurement. Phasor measurement units can also be used to increase reliability by relaying line condition data through the communication network quickly. Phasor measurement unit implementation may enable transmission operators to integrate variable resources and energy storage more effectively while minimizing service disruptions.

PacifiCorp participated in the Western Interconnection Synchrophasor Project (WISP). The project resulted in eight phasor measurement units installed in eight PacifiCorp substations. These devices are currently collecting data and will support PacifiCorp's and Peak Reliability's[1] goal of maintaining power system stability. The system of synchrophasors will be used to identify and analyze system vulnerabilities and disturbances. It will also assist in preventing system blackouts and provide historical data for the analysis of any future power system failure. Peak Reliability is continuing to develop data access for utility participants. PacifiCorp has discontinued sending data to Peak Reliability as part of their WISP program since they currently do not operationally utilize the data. Once Peak Reliability has their advanced application functionality enabled, which is expected in 2017, PacifiCorp expects to reinitiate data flow to Peak Reliability.

Phasor measurement units will also be used to satisfy the validation requirements in North American Electric Reliability Corporation (NERC)-MOD-033, a reliability standard proposed to improve accurate data collection and planning models. Planning models analyzing the transmission system reliability are required to compare model results to real-world values in order to meet model validation requirements.

Distribution System Efforts

Distribution Automation

Distribution automation (DA) is a wide field of smart grid technology and applications, which focuses on using sensors and data collection on the distribution system, as well as automatically adjusting the system to optimize performance. It can also provide operational efficiency, peak load management, equipment failure prediction, and decreased restoration times after failure. PacifiCorp is working on several distribution automation initiatives.

- In Oregon, PacifiCorp has identified 40 circuits on which a DA cost benefit analysis will be performed. These 40 circuits were selected based on a set of criteria intended to minimize the cost of implementation and maximize the reliability benefit. The feasibility of utilizing an advanced metering infrastructure network for the communications of the distribution automation system will also be addressed.
- PacifiCorp has installed Fusesaver™ devices and electronic reclosers with the capability of enabling communications through a retrofit in the future.
- A pilot project in Walla Walla, Washington is underway to demonstrate the feasibility and effectiveness of distribution automation, including a fault location isolation and restoration application.
- A feasibility study to determine the cost and benefit of retrofitting an existing source/transfer scheme to a distribution automation scheme is underway in Salt Lake City, Utah.
- PacifiCorp installed communicating faulted circuit indicators on five circuits in eastern Utah in March 2014. These devices have proven capable of improving reliability by reducing the time required to report and locate a fault. PacifiCorp is still evaluating the cost and feasibility of integrating these devices in its outage management system before further deployment.

[1] Peak Reliability (Peak) is a company wholly independent of WECC that performs the Reliability Coordinator (RC) function in its RC Area in the Western Interconnection.

Customer Information Efforts

Advanced Metering Infrastructure

A key effort for PacifiCorp in 2016 was the development of a detailed business case for advanced metering infrastructure in Oregon. Advanced metering infrastructure is an integrated system of smart meters, communications networks, and data management systems with two-way communication. PacifiCorp's objectives were to identify a solution and strategy that would deliver tangible projected benefits to our customers and deliver economically-driven financial results while minimizing the impact on consumer rates. A request for information followed by a request for proposals was solicited to further evaluate the economics and impacts of an advanced metering infrastructure rollout in Oregon. The financial analysis of proposals indicated a positive business case due to decreasing costs of advance metering technology and increasing operations and maintenance costs. As a result, Pacific Power committed to proceed with deployment of an advanced metering infrastructure system in Oregon.

The advanced metering infrastructure program in Oregon will replace 590,000 existing customer meters with smart meters and install an advanced metering system to remotely read and operate customer meters. The project will provide a web portal for customers, capture hourly meter data, perform on demand meter reads, remotely connect and disconnect power, verify outage inquiries, remotely reprogram meters, and collect data on power quality and tampering. This advanced metering infrastructure project will provide a network and metering infrastructure to improve customer service and enable future smart grid applications. Project benefits include reduced operations and maintenance costs, a platform for future smart grid applications, increased worker safety, reduced emissions, and increased data for efficient management of the network. Meter installations began in 2017 and the project completion date is scheduled for the end of 2019.

Future Smart Grid

PacifiCorp is continuing to evaluate smart grid technologies and piloted projects that might benefit customers. PacifiCorp regularly develops smart grid reports to examine the quantifiable costs and benefits of individual components of the smart grid. While the net present value of implementing a comprehensive smart grid system throughout PacifiCorp is negative at this time, PacifiCorp has implemented specific projects and programs that have positive benefits for customers, and continues to explore pilot projects in other areas of interest. In order to reduce risks to the company, grid, customers, and supporting systems, it is essential to identify affordable leading technologies and implement industry best practices.

APPENDIX F – FLEXIBLE RESERVE STUDY

Introduction

This 2019 Flexible Reserve Study (FRS) estimates the regulation reserve required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation (NERC) reliability standards as well as the incremental cost of this regulation reserve. The FRS also compares PacifiCorp's overall operating reserve requirements, including both regulation reserve and contingency reserve, to its flexible resource supply over the Integrated Resource Plan (IRP) study period.

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,[1] as well as the amount of contingency reserve required in order to comply with NERC standard BAL-002-WECC-2.[2] BAL-001-2 is a regulation reserve standard that became effective July 1, 2016, and BAL-002-WECC-2a is a contingency reserve standard that became effective January 24, 2017. 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."[3]

Apart from disturbance events that are addressed through contingency reserve, regulation reserve is necessary to compensate for changes in load demand and generation output, so as 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[4] (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 2017 through December 2017 for load, wind, solar, and Non-VERs. PacifiCorp's primary analysis, focuses on the

1 NERC Standard BAL-001-2, www.nerc.com/files/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.

2 NERC Standard BAL-002-WECC-2a, www.nerc.com/files/BAL-002-WECC-2a.pdf, which became effective January 24, 2017. BAL-002-WECC-2a clarified that non-traditional resources can qualify as spinning reserves if they meet technical and performance requirements.

3 NERC Glossary of Terms: www.nerc.com/files/glossary_of_terms.pdf, updated May 13, 2019.

4 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 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").

variability of load, wind, solar, and Non-VERs during 2017. A supplemental analysis discusses how the total variability of the PacifiCorp system changes with varying levels of load, 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 as a result 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 similar to that employed in PacifiCorp's previous regulation reserve requirement analysis in the 2017 IRP, but has been enhanced in some key ways.[5] First, regulation reserve requirements are co-optimized in a quantile regression model. Second, actual hourly load schedules are employed as compared to the proxy schedules developed in the previous study. Third, the FRS uses actual solar schedules reflecting the widespread penetration of utility scale solar facilities that has occurred since the previous study. Fourth, the FRS reflects updated data based on actual operational experience, including the data and benefits from PacifiCorp's participation in the EIM.[6]

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 was applied in the Planning and Risk (PaR) production cost model to determine the cost of the reserve requirements associated with incremental wind and solar capacity. These integration costs are applied to potential wind and solar resource options in the System Optimizer (SO) model portfolio expansion model, which does not otherwise account for regulation reserve requirements. When a portfolio is studied in the PaR model, the regulation reserve requirements specific to that portfolio are calculated and included in the study inputs, such that the production cost of the requirements is incorporated in the reported results, so it is not necessary to add integration costs to the PaR results.

Overview

The FRS first estimates 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.

[5] 2017 Flexible Reserve Study, Appendix F in Volume II of PacifiCorp's 2017 IRP report: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf

[6] PacifiCorp presented the FRS for the 2019 IRP to the Technical Review Committee (TRC) that reviewed the FRS for the 2017 IRP. In light of the robust methodology developed for the 2017 IRP, and the relatively limited modifications for the 2019 IRP, TRC members indicated that continuing the formal review process was unnecessary.

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 the 2017 IRP is shown in Table F.1 and Table F.2.

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)
2017 Base Case	2,757	1,050	998	38%	617
2019 Base Case	2,750	1,021	994	47%	531

Table F.2 - 2019 FRS Flexible Resource Costs as Compared to 2017 Costs, $/MWh

	Wind 2017 FRS (2016$)	Solar 2017 FRS (2016$)	Wind 2019 FRS (2018$)	Solar 2019 FRS (2018$)
Study Period	2017	2017	2018-2036	2018-2036
Intra-hour Reserve	$0.43	$0.46	$1.11	$0.85
Inter-hour System Balancing	$0.14	$0.14	n/a	n/a
Total Flexible Resource Cost	$0.57	$0.60	$1.11	$0.85

In the 2017 FRS, PacifiCorp calculated an inter-hour system balancing integration cost reflecting sub-optimal gas plant commitment based on day-ahead load, wind, and solar forecasts, rather than actuals. However, gas plants are dispatched in EIM to meet regional demand, not just the PacifiCorp demand reflected in the PaR model, and quick-start gas plants can be committed within EIM. In light of the minimal impact of the calculated cost in the 2017 IRP, and possible interaction with EIM, the company opted not to include inter-hour system balancing integration costs in the 2019 IRP.

The 2019 FRS results are applied in the 2019 IRP portfolio development process as a cost for wind and solar generation resources. Once candidate resource portfolios are developed using the SO model, the PaR model is used to evaluate portfolio risks. The PaR model inputs include regulation reserve requirements specific to the resource portfolio developed using the SO model. As a result, the IRP risk analysis using PaR includes the impact of differences in regulation reserve requirements between portfolios.

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 the North American Electric Reliability Corporation (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-2a.[7] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2.[8] Frequency response reserve is capacity that PacifiCorp holds available to ensure compliance with NERC standard BAL-003-1.[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-2a 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. In accordance with Requirement 2 of BAL-002-WECC-2a, at least half of a BAA's requirement must be met with "spinning" resources that are online and immediately responsive to system frequency deviations, while the remainder can come 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…*

[7] NERC Standard BAL-002-WECC-2a – Contingency Reserve: www.nerc.com/files/BAL-002-WECC-2.pdf
[8] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: www.nerc.com/files/BAL-001-2.pdf
[9] NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting: www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.pdf
[10] Retirement of the minimum spinning reserve obligation in BAL-002-WECC-2a is being considered due to redundancy with frequency response obligations under BAL-003-1. More information is available online at: www.wecc.org/Standards/Pages/WECC-0115.aspx

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 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. 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 2019 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 on 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. In order to continue providing flexible capacity in the following hour, energy must be available in storage for that hour as well. The likelihood of actually 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-003-1 specifies that each BAA must arrest frequency deviations and support the interconnection when frequency drops below the scheduled level. When a frequency drop occurs as a result 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 2019 Frequency Response Obligation was 20.2 MW/0.1Hz for PACW, and 47.4 MW/0.1Hz for PACE. PacifiCorp's combined obligation amounts to 67.6 MW for a frequency drop of 0.1 Hz, or 202.8 MW for a frequency drop of 0.3 Hz.

The performance measurement for contingency reserve under the Disturbance Control Standard (BAL-002-3)[11], 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 are capable of supporting 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 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,

[11] NERC Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event: www.nerc.com/pa/Stand/Reliability Standards/BAL-002-3.pdf

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. In order 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 in order 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.[12]

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 of its transmission customers pursuant to the provisions of Attachment T to PacifiCorp's Federal Energy Regulatory Commission (FERC) approved Open 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.

[12] 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

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 the majority of 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 was downloaded from PacifiCorp's Ranger PI system and 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.[13] Wind and solar, in comparison to load, often have larger upward and downward

[13] Order No. 764 at P 281; Order No. 764-B at P 210.

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*."[14] 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 includes 2,750 megawatts of wind and 1,021 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."[15]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 on in the study.

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.

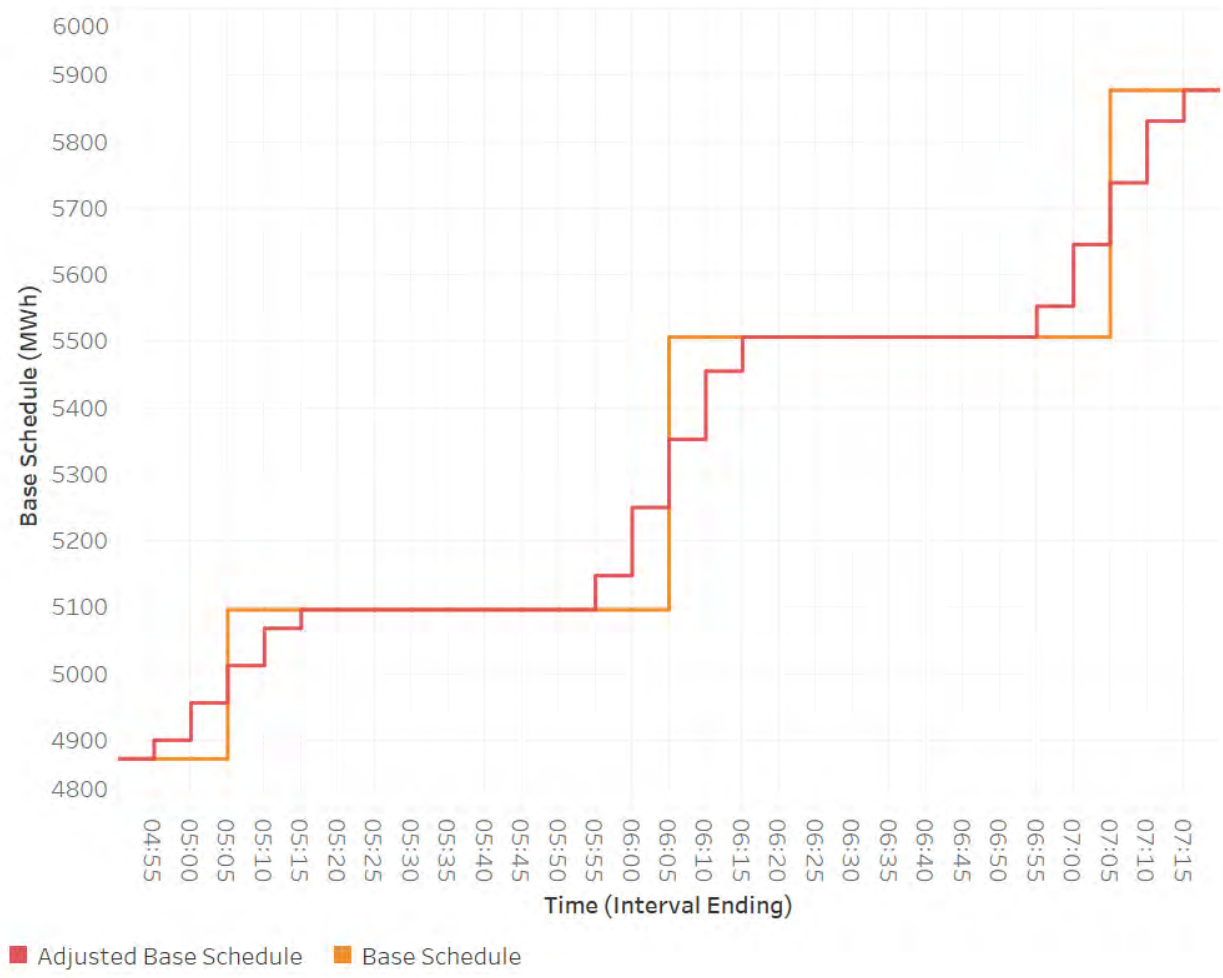
Base Schedule Ramping Adjustment

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

[14] Order No. 764 at P 20 (emphasis added).
[15] *Id.* at P 92.

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:

- Stuck meter/flat meter reading

- Telemetry spike/poor connection to meter

Wind, Solar, and Non-VERs:

- Generator trip events
- 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.

Similarly, rapid spikes in load either up or down are also unlikely to be a 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. 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 back within a short period, were assumed to have been covered through contingency reserve deployment or to reflect inaccurate load measurements. Because they don't reflect periods that require regulation reserve deployment, such intervals are excluded from the analysis.

As with Load, certain Wind and Non-VER deviations are more likely to be a result of conditions that allow for the deployment of contingency reserve, rather than regulation reserve. In particular, contingency reserve can be deployed to compensate for unexpected generator outages. For Non-VERs, these are relatively straightforward—namely, periods when generation drops to zero despite base schedules indicating otherwise. Certain Wind outages also qualify as contingency events. Notably, wind generators can be curtailed when wind speed exceeds the maximum rating of the equipment (sometimes referred to as "high speed cutout"). In such instances, generation is curtailed until wind speeds drop back into a safe operating range in order to protect the equipment. When wind speed oscillates above and below the cut-off point, generation may ramp down and up repeatedly. Because events which qualify for deployment of contingency reserve do not require deployment of regulation reserve they have been excluded from the analysis.

As the regulation reserve requirements are calculated using a rolling thirty-minute timeline, data from the prior hour is necessary during the first several five-minute intervals of the next hour. An error in one hour thus results in the need to remove the following hour. This is relevant to error adjustments for both Wind and Non-VERs.

After review of the data for each of the above anomaly types, and out of 105,120 five-minute intervals evaluated, only 1.1 percent and 0.52 percent of the total FRS term hours were removed from PACW and PACE, respectively. The system-wide error rate was 1.36 percent, slightly lower than the sum of the PACW and PACE rates due to coincident hours. 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 actually 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.[16]

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 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.

[16] *See* footnote 12 above for explanation of PacifiCorp's use of the T-40 base schedule time point in the FRS.

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.[17] 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 has experience operating under the new standard, even though it did not become effective until 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.

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

[17] NERC Standard BAL-001-2, www.nerc.com/files/BAL-001-2.pdf

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 2019 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.

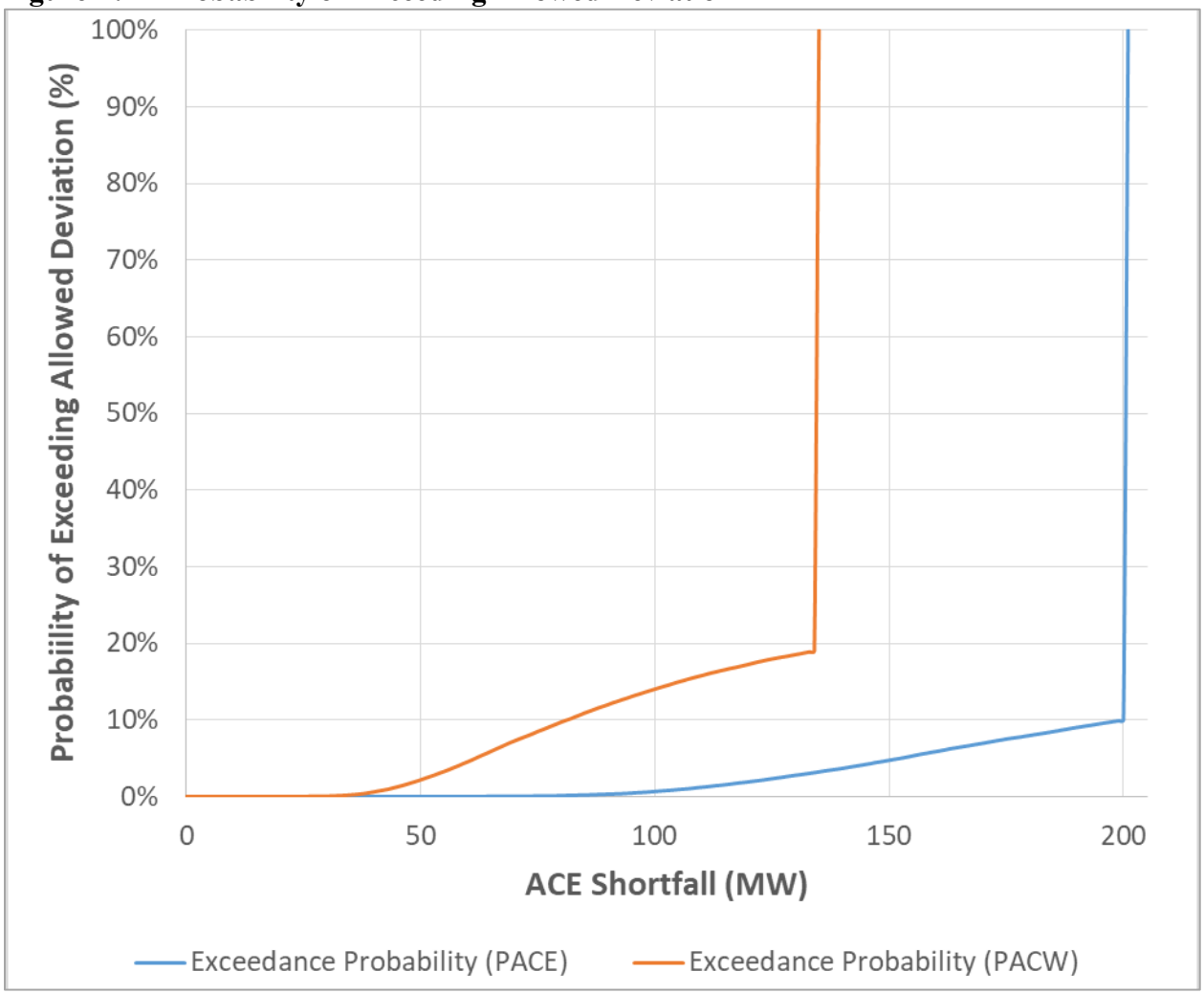
The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 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 doesn't 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, a 43 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.[18,19] This cap is reflected in Figure F.2.

[18] "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

[19] "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

Figure F.2 - Probability of Exceeding Allowed Deviation



In 2017, 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

In order 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. The regression variables consist of:

- The combined deviation of load, wind, solar, and Non-VERs;
- Forecasted load as a percentage of peak load;
- Forecasted wind generation as a percentage of total system wind capacity;
- Forecasted solar generation as a percentage of total system solar capacity; and
- Forecasted Non-VER generation as a percentage of maximum Non-VER schedules.

The combined deviations of load, wind, solar and non-VERs (Combined Diversity Error) is calculated as [Load Error – Wind Error – Solar Error – Non VER Error] as illustrated below in Table F.3 for PACE.

Table F.3 - Combined Diversity Error Example

Trading Date	Trading Hour	Trading Interval	Load Error	Non VER Error	Wind Error	Solar Error	Combined Diversity Error
1/1/2017	3	5	49	-5	-21	0	75
1/1/2017	3	10	40	-6	-16	0	61
1/1/2017	3	15	36	-3	-14	0	53
1/1/2017	3	20	35	-6	-55	0	97
1/1/2017	3	25	34	-6	-48	0	87
1/1/2017	3	30	36	-4	-26	0	67
1/1/2017	3	35	36	-7	-41	0	84
1/1/2017	3	40	32	-8	-39	0	80
1/1/2017	3	45	30	-5	-39	0	74
1/1/2017	3	50	31	2	-37	0	66
1/1/2017	3	55	37	1	-37	0	73
1/1/2017	3	60	45	2	-32	0	75

The individual errors (load, wind, solar and non-VERs) are calculated as the difference between the actual meter data and the adjusted hourly base schedules as illustrated below for PACE wind in Table F.4.

Table F.4 – Wind Error Example

Trading Date	Trading Hour	Trading Interval	Adjusted Base Schedules	Actuals	Wind Error
1/1/2017	3	5	957	936	-21
1/1/2017	3	10	956	940	-16
1/1/2017	3	15	955	941	-14
1/1/2017	3	20	955	900	-55
1/1/2017	3	25	955	908	-48
1/1/2017	3	30	955	929	-26
1/1/2017	3	35	955	914	-41
1/1/2017	3	40	955	916	-39
1/1/2017	3	45	955	916	-39
1/1/2017	3	50	955	918	-37
1/1/2017	3	55	954	917	-37
1/1/2017	3	60	951	919	-32

An illustration of the combined diversity error and the forecasted levels of load as a percentage of peak load, the forecasted levels of wind as a percentage of total system capacity, the forecasted levels of solar as a percentage of total system capacity and the forecasted levels of Non-VERs as a percentage of peak schedule are illustrated below in Table F.5 for PACE.

Table F.5 – Regression Inputs Example

Trading Date	Trading Hour	Trading Interval	Combined Diversity Error	Wind Forecast	Solar Forecast	Load Forecast	Non VER Forecast
1/1/2017	3	5	72	50.5%	0%	56%	55%
1/1/2017	3	10	60	50.4%	0%	56%	55%
1/1/2017	3	15	53	50.3%	0%	56%	55%

1/1/2017	3	20	97	50.3%	0%	56%	55%
1/1/2017	3	25	87	50.3%	0%	56%	55%
1/1/2017	3	30	67	50.3%	0%	56%	55%
1/1/2017	3	35	84	50.3%	0%	56%	55%
1/1/2017	3	40	80	50.3%	0%	56%	55%
1/1/2017	3	45	74	50.3%	0%	56%	55%
1/1/2017	3	50	66	50.3%	0%	56%	55%
1/1/2017	3	55	68	50.3%	0%	56%	55%
1/1/2017	3	60	58	50.1%	0%	56%	55%

The Load Forecast, Wind Forecast, Solar Forecast and Non VER Forecast are calculated as a percentage of some measure of capacity or peak. The forecasted levels of PACE wind as a percentage of total system capacity is illustrated below in Table F.6.

Table F.6 – Wind Forecast Level Example

Trading Date	Trading Hour	Trading Interval	Adjusted Base Schedules	Capacity	Wind Forecast
1/1/2017	3	5	957	1898	50.5%
1/1/2017	3	10	956	1898	50.4%
1/1/2017	3	15	955	1898	50.3%
1/1/2017	3	20	955	1898	50.3%
1/1/2017	3	25	955	1898	50.3%
1/1/2017	3	30	955	1898	50.3%
1/1/2017	3	35	955	1898	50.3%
1/1/2017	3	40	955	1898	50.3%
1/1/2017	3	45	955	1898	50.3%
1/1/2017	3	50	955	1898	50.3%
1/1/2017	3	55	954	1898	50.3%
1/1/2017	3	60	951	1898	50.1%

Quantile regression is a type of regression analysis. Whereas the typical method of ordinary least 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. For the 2019 FRS the response variable – Combined Diversity Error – was expressed as a function of four predictor variables – Wind Forecast, Solar Forecast, Load Forecast and Non VER Forecast. Each predictor variable contributes to the regression as a combination of linear, square, and cubic effects. Specifically:

$$\begin{gathered}\text{Combined Diversity Error} \quad \text{varies as a function of:} \\ Wind\ Forecast \ + \ Wind\ Forecast^2 \ + \ Wind\ Forecast^3 \ + \\ Solar\ Forecast \ + \ Solar\ Forecast^2 \ + \ Solar\ Forecast^3 \ + \\ Load\ Forecast \ + \ Load\ Forecast^2 \ + \ Load\ Forecast^3 \ + \\ Non\ VER\ Forecast \ + \ Non\ VER\ Forecast^2\end{gathered}$$

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.

2017 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 dynamical Balancing Authority ACE Limit. The combined diversity error system requirements are discussed later on in the study.

Wind

Figure F.3 illustrates the relationship between the regulation reserve requirements for PACE wind during 2017 and the forecasted level of output, stated as a capacity factor (*i.e.*, a percentage of the nameplate wind capacity). Figure F.4 illustrates this relationship for PACW.

Figure F.3 - Wind Regulation Reserve Requirements by Forecast - PACE

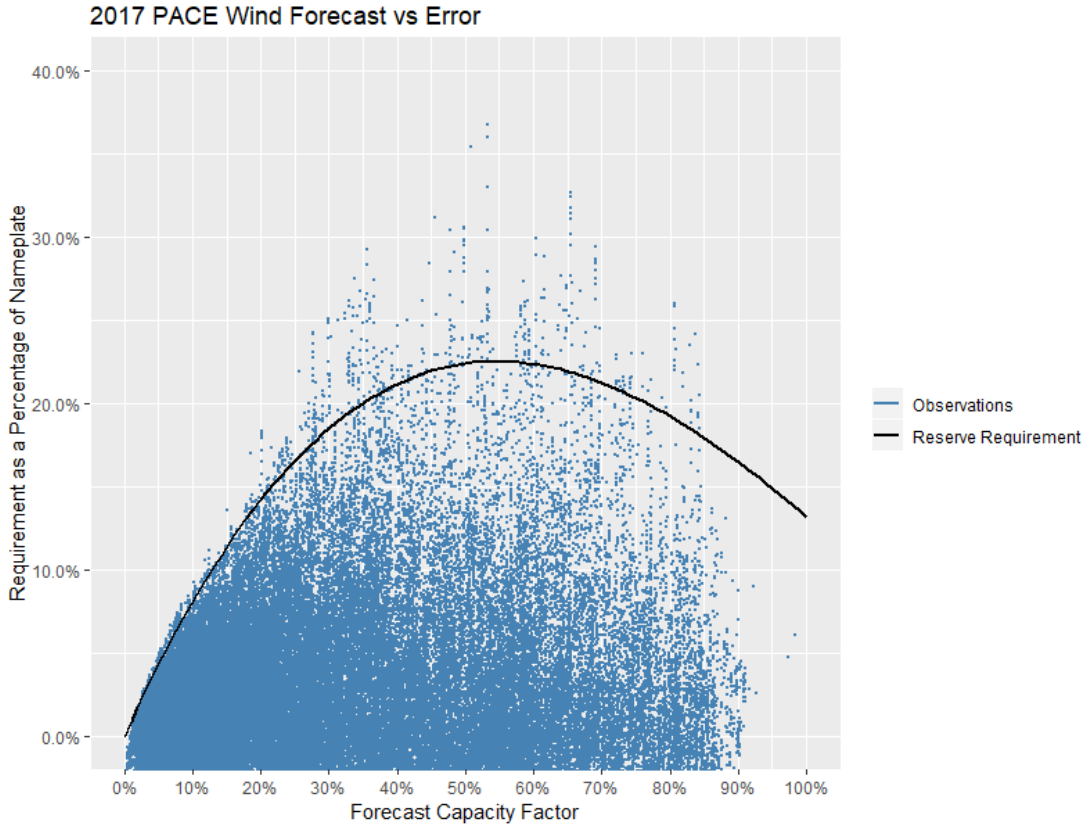
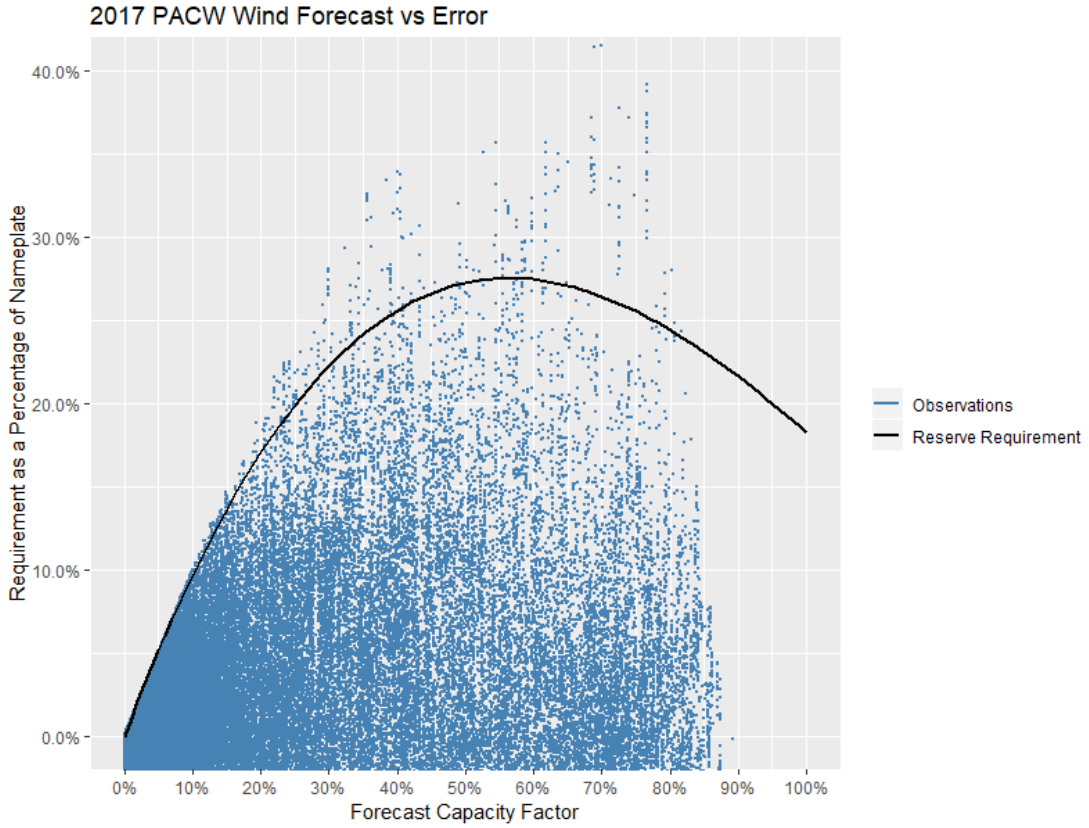


Figure F.4 - Wind Regulation Reserve Requirements by Forecast Capacity Factor-PACW



The forecast results in an average 2017 stand-alone regulation reserve requirement for wind of 434 MW for the PacifiCorp system, or approximately 15.8 percent of nameplate capacity.

Solar

Figure F.5 illustrates the relationship between the regulation reserve requirements for PACE solar during 2017 and the forecasted level of output, stated as a capacity factor (*i.e.*, a percentage of the nameplate solar capacity). Figure F.6 illustrates this relationship for PACW.

Figure F.5 - Solar Regulation Reserve Requirements by Forecast Capacity Factor-PACE

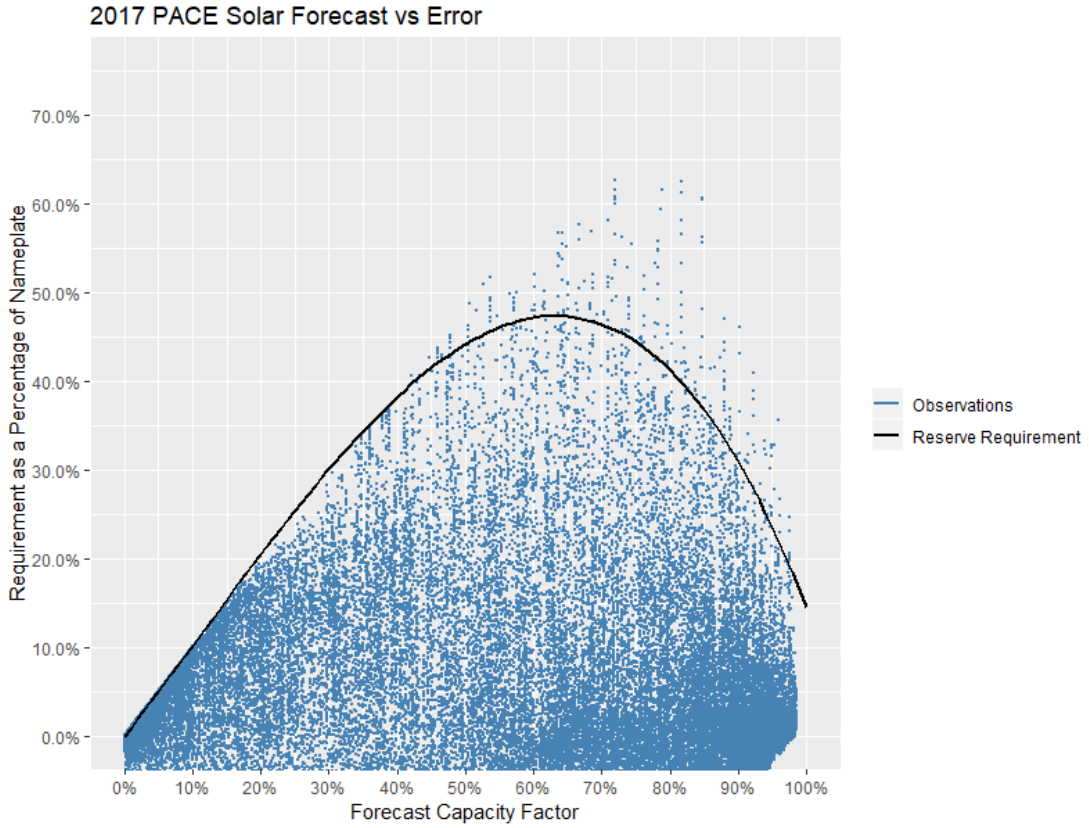
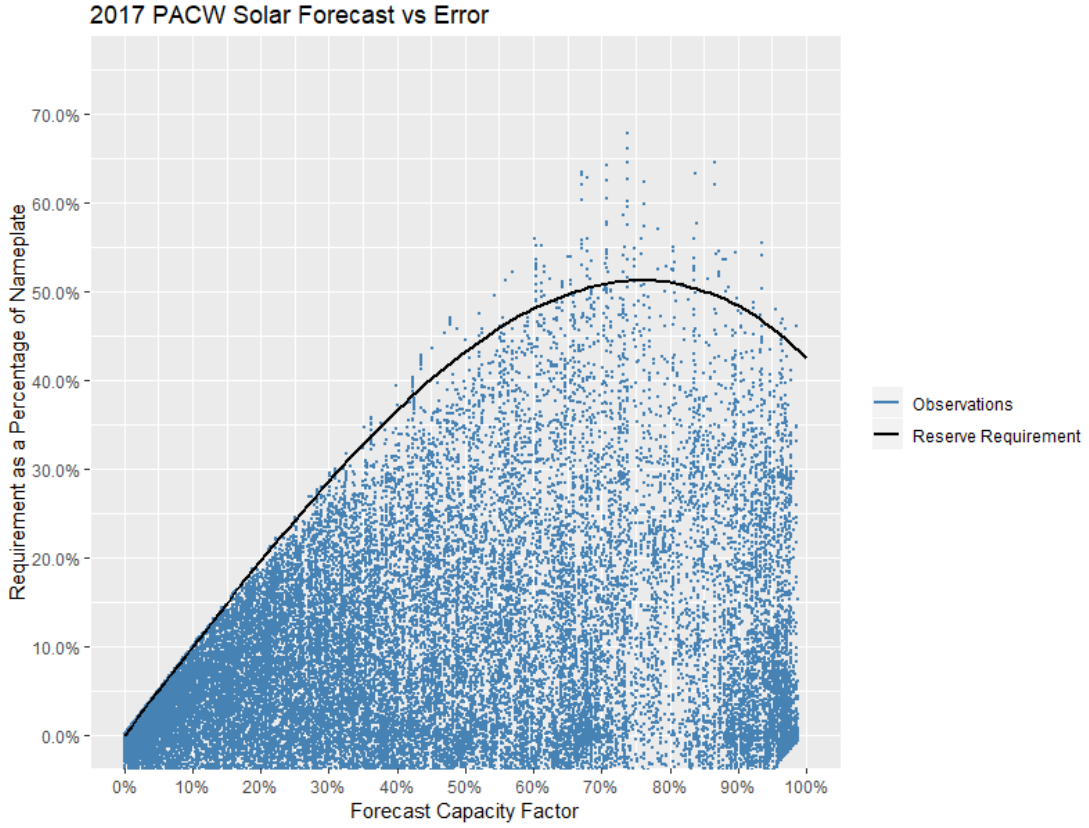


Figure F.6 - Solar Regulation Reserve Requirements by Forecast Capacity Factor-PACW



The forecast results in an average 2017 stand-alone regulation reserve requirement for solar of 145 MW for the PacifiCorp system, or approximately 14.8 percent of nameplate capacity.

Non-VERs

Figure F.7 below illustrates the regulation reserve requirements for PACE Non-VERs during 2017 as a function of the forecasted level of output, stated as a peak schedule factor (*i.e.*, a percentage of the peak Non-VER schedule observed for 2017). Figure F.8 illustrates this relationship for PACW.

Figure F.7 – Non-VER Regulation Reserve Requirements by Forecast Schedule Factor-PACE

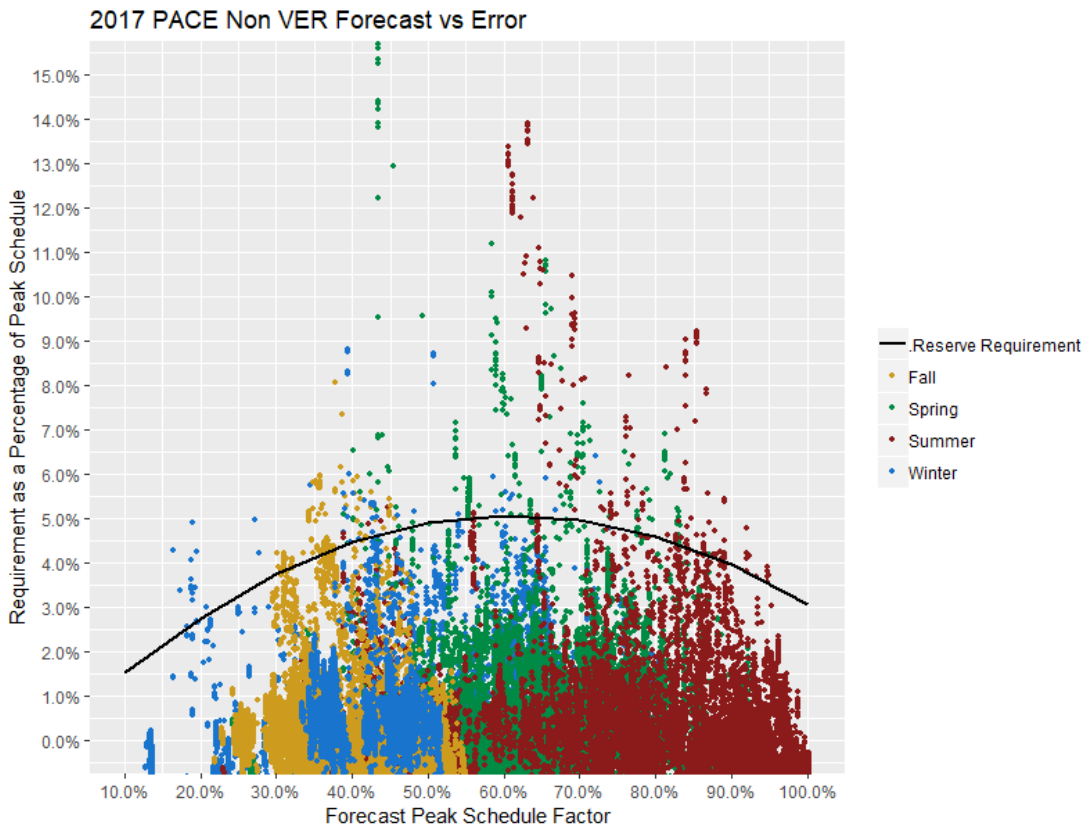
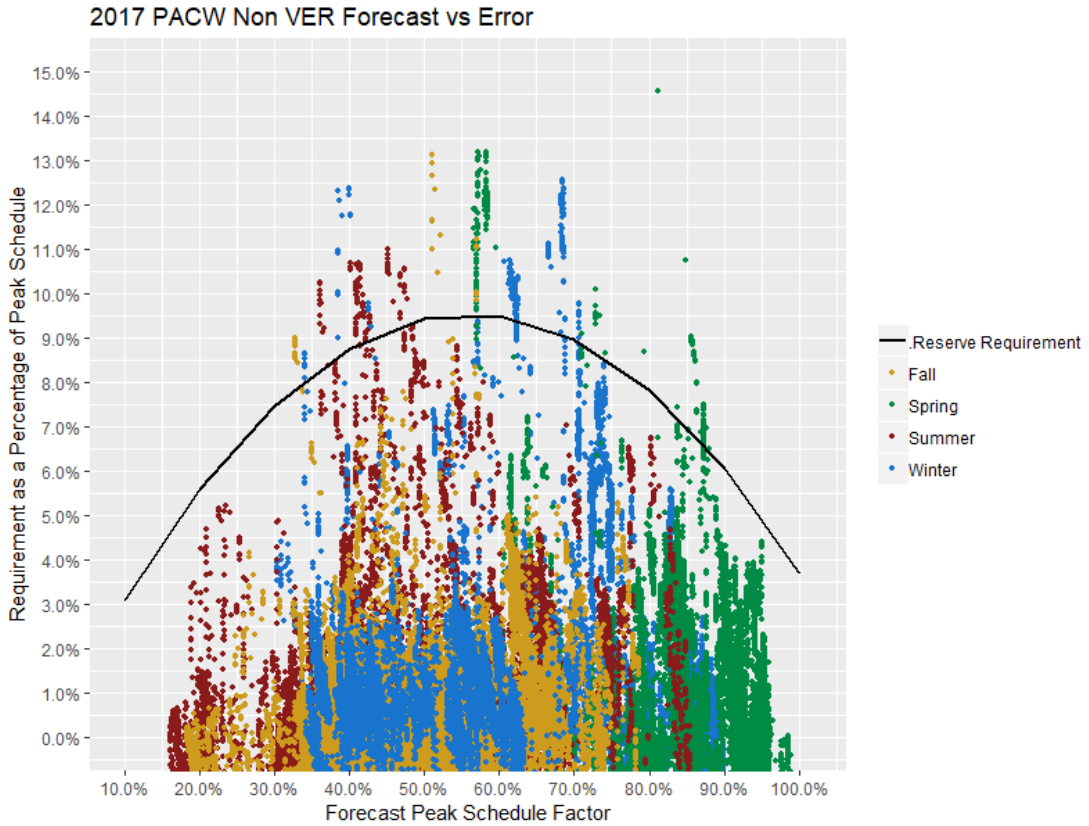


Figure F.8 – Non-VER Regulation Reserve Requirements by Forecast Schedule Factor-PACW



The forecast results in an average 2017 stand-alone regulation reserve requirement for non VERs of 110 MW for the PacifiCorp system, or approximately 5.7 percent of the peak schedule.

Load

Figure F.9 below illustrates the regulation reserve requirements for PACE load during 2017 as a function of the forecasted level of output, stated as a peak load factor (*i.e.*, a percentage of the peak load observed during 2017) for PACE. Figure F.10 illustrates this relationship for PACW.

Figure F.9 – Stand-alone Load Regulation Reserve Requirements-PACE

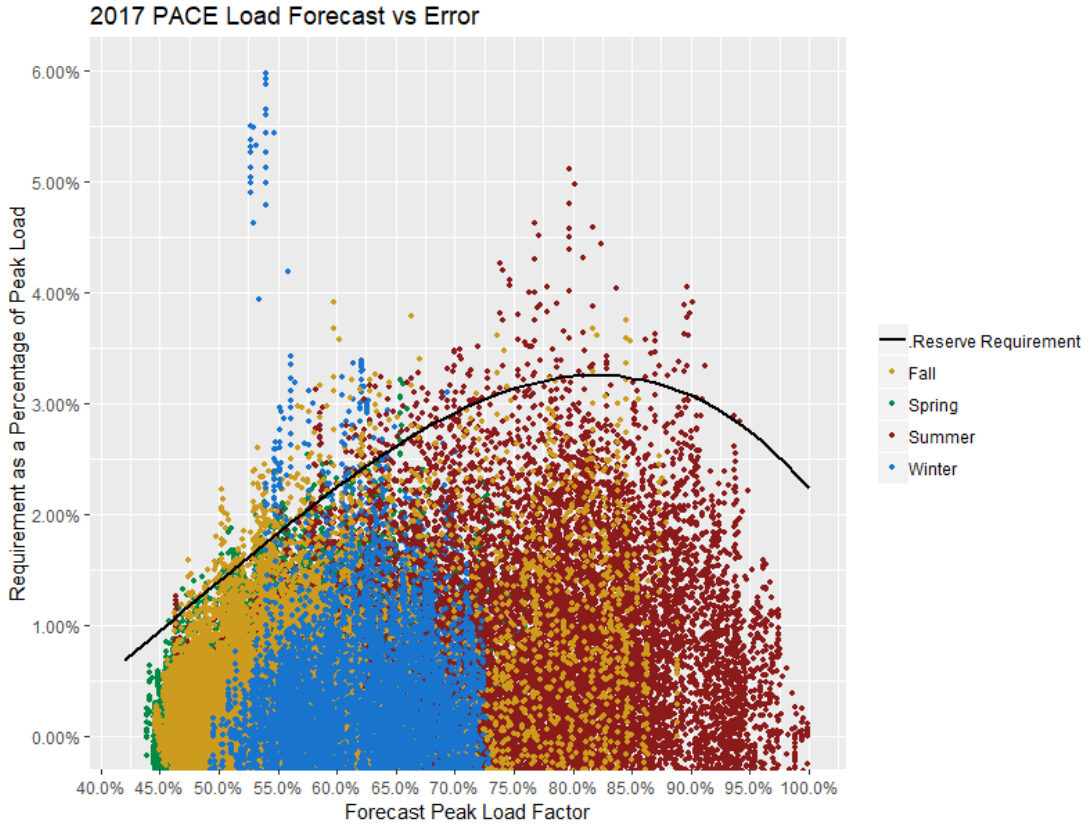
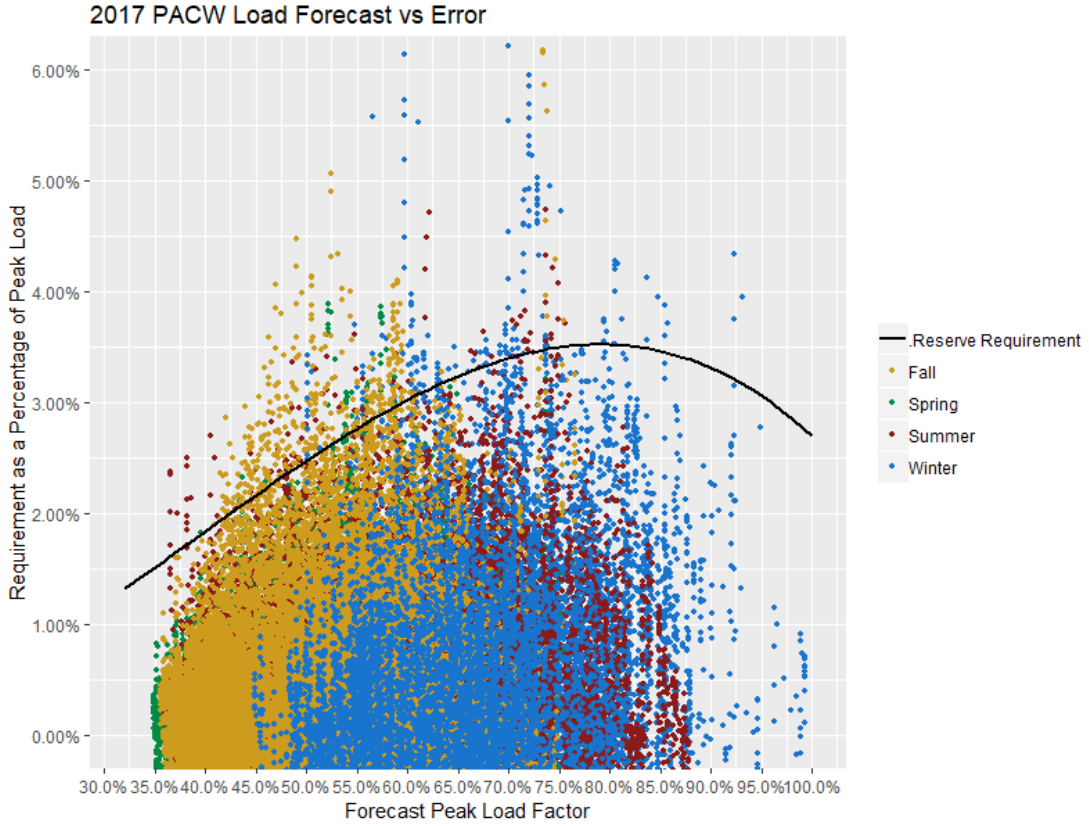


Figure F.10 – Stand-alone Load Regulation Reserve Requirements-PACW



The forecast results in an average 2017 stand-alone regulation reserve requirement for load of 305 MW for the PacifiCorp system, or approximately 3.0 percent of the peak load.

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. A number of 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, as a result 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. For this reason the portfolio regulation requirements were calculated on the Combined Diversity Error.

As shown in Table F.7 below, PacifiCorp calculated the proportional reduction to the standalone requirements that could be applied such that the PacifiCorp system achieves the target determined through the quantile regression on the Combined Diversity Error. A total portfolio requirement of 635 MW was the result of this regression, a reduction of 36 percent. Applying this 36 percent reduction to each of the stand-alone regulation forecasts results in the diversity benefits shown in the second column. The last column shows the regulation requirements for each class after subtracting the portfolio diversity benefit.

Table F.7 - Results with PacifiCorp Portfolio Diversity

Scenario	Stand-alone Regulation Forecast (aMW)	Diversity Benefit (aMW)	Portfolio Regulation Forecast (aMW)
Non-VER	110	(40)	70
Load	305	(110)	195
VER - Wind	434	(157)	277
VER - Solar	145	(53)	93
Total	**994**	**(360)**	**635**

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, wind, and solar 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.8 below provides a numeric example of uncertainty requirements and application of the calculated diversity benefit.

Table F.8 - EIM Diversity Benefit Application Example

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	37.0%	61	104
2	600	110	165	100	975	636	339	34.8%	57	108
3	650	110	165	110	1,035	689	346	33.4%	55	110
4	667	120	180	113	1,080	742	338	31.3%	56	124

While the diversity benefit is uncertain, that uncertainty is not significantly different from the uncertainty in the Balancing Authority ACE Limit described above. In the 2019 FRS, PacifiCorp has credited the regulation reserve forecast with a historical distribution of calculated EIM diversity benefits. While this FRS considers regulation reserve requirements in 2017, 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 March 2018 through the beginning of this study in July 2018. Relatively small incremental EIM diversity benefits are expected going forward as additional entities participate in EIM; however, operational data on new participants was not available at the time the study was prepared.

The inclusion of EIM diversity benefits in the 2019 FRS reduces the 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.9 below, the resulting regulation reserve requirement is 531 MW, a 47 percent reduction (including the portfolio diversity benefit) compared to the stand-alone requirement for each class. The average regulation reserve requirement is reduced by 104 MW relative to the PacifiCorp portfolio reserve requirement without the EIM diversity benefit. The portfolio regulation forecast is expected to achieve an LOLP of 0.5 hours per year, based on a quantile regression at a 99.35 percent exceedance level.

Table F.9 - 2017 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 (%)	2017 Capacity (MW)	Rate Determinant
Non-VER	110	5.7%	59	3.1%	1,912	12 CP
Load	305	3.0%	163	1.6%	10,044	12 CP
VER - Wind	434	15.8%	232	8.4%	2,750	Nameplate
VER - Solar	145	14.8%	78	7.9%	983	Nameplate
Total	**994**		**531**			

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 2017 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 the majority of 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 2017 Regulation Reserve Forecast described above.

To evaluate CPS1 requirements, PacifiCorp compared the net load change for each five-minute interval in 2017 to the corresponding value for Requirement 2 compliance in that hour from the 2017 Regulation Reserve Forecast, after accounting for diversity (resulting in the 531 MW average requirement shown in Table F.9). Resources may deploy for Requirement 2 compliance over up to 30 minutes, so the average requirement of 531 MW would require ramping capability of at least 17.7 MW per minute (531 MW / 30 minutes).

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. Resources capable of ensuring compliance in 95 percent of intervals are expected to be sufficient to meet CPS 1, and given that ACE may deviate in either a positive or negative direction, the 97.5th percentile of incremental requirements was evaluated. This corresponds to 87 MW, or approximately 16.3 percent of the average Requirement 2 value. Because this value is for a five-minute interval, meeting it would require a ramping capability of at least 17.3 MW per minute (87 MW / 5 minutes). This value is actually slightly lower than the ramping capability for Requirement 2.

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-003-1, based on median response during the largest events.

In light of the overlaps with BAL-001-2 Requirement 2 and BAL-003-1 described above, CPS1 compliance is not expected to result in an additional requirements beyond what is necessary to comply with those standards.

Incremental 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 measures. As PacifiCorp's portfolio grows, the diversity of that portfolio is also expected to increase. As a result, incremental regulation reserve requirements are expected to be lower than the average requirement for a given portfolio.

The need to develop realistic deviation data for a period during which resources did not exist makes measuring an incremental diversity effect a difficult proposition. Instead, PacifiCorp's FRS evaluated the change in regulation reserve requirements associated with cumulatively stacking the individual wind and solar facilities throughout the two BAAs. Under this methodology as each MW of VERs is added to the system the rate of increase of the regulation reserve requirement is quantified and incorporated in the forecasted portfolio regulation results discussed later on in the study. Figure F.11 and Figure F.12 show this relationship between increased capacity and increasing reserve requirements for wind and solar by BAA.

Similarly for load the relationship between the daily peak load and the daily maximum error over the course of 2017 was observed for both BAAs and this relationship was extrapolated forward to develop a multiplier for the effect of peak load on the reserve requirements. A linear relationship between daily peak load and daily maximum error was observed for both BAAs as illustrated in Figure F.13 through Figure F.14.

Figure F.11 – Incremental Wind Capacity

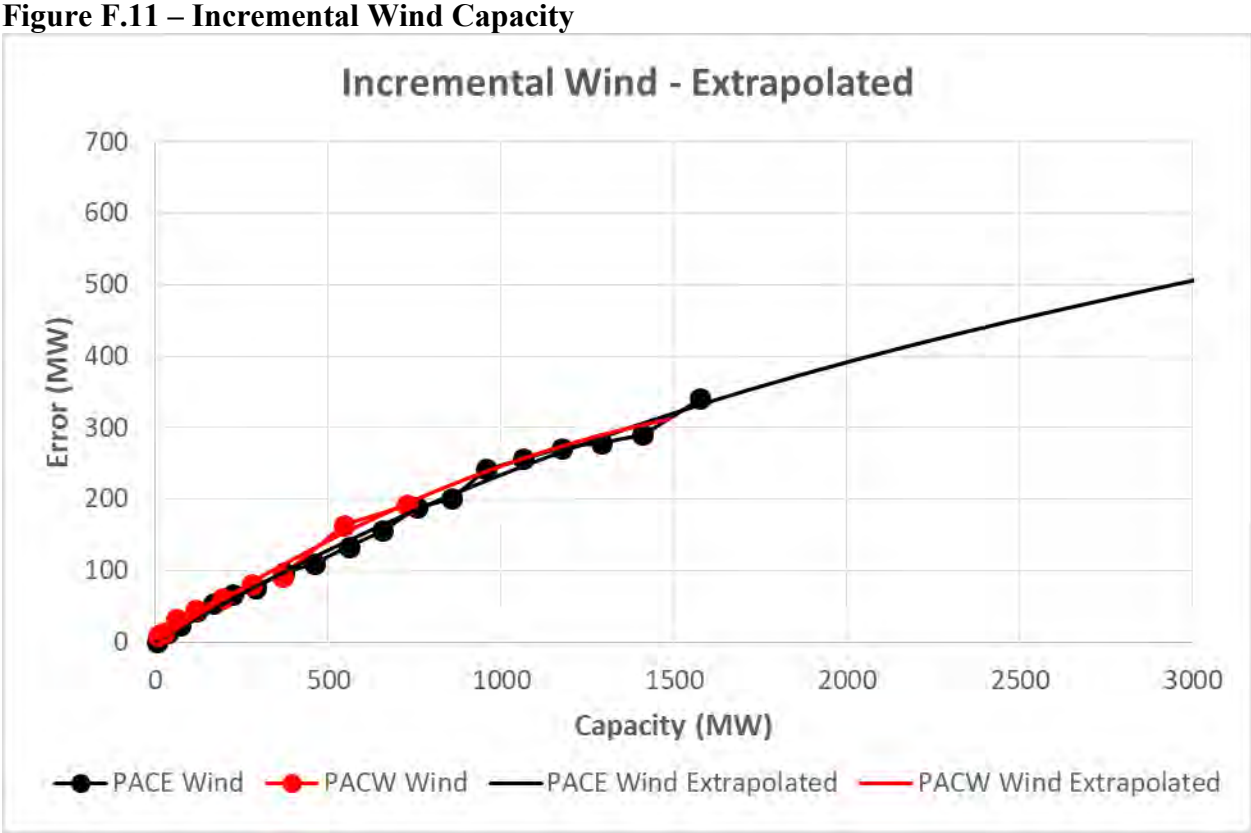


Figure F.12 – Incremental Solar Capacity

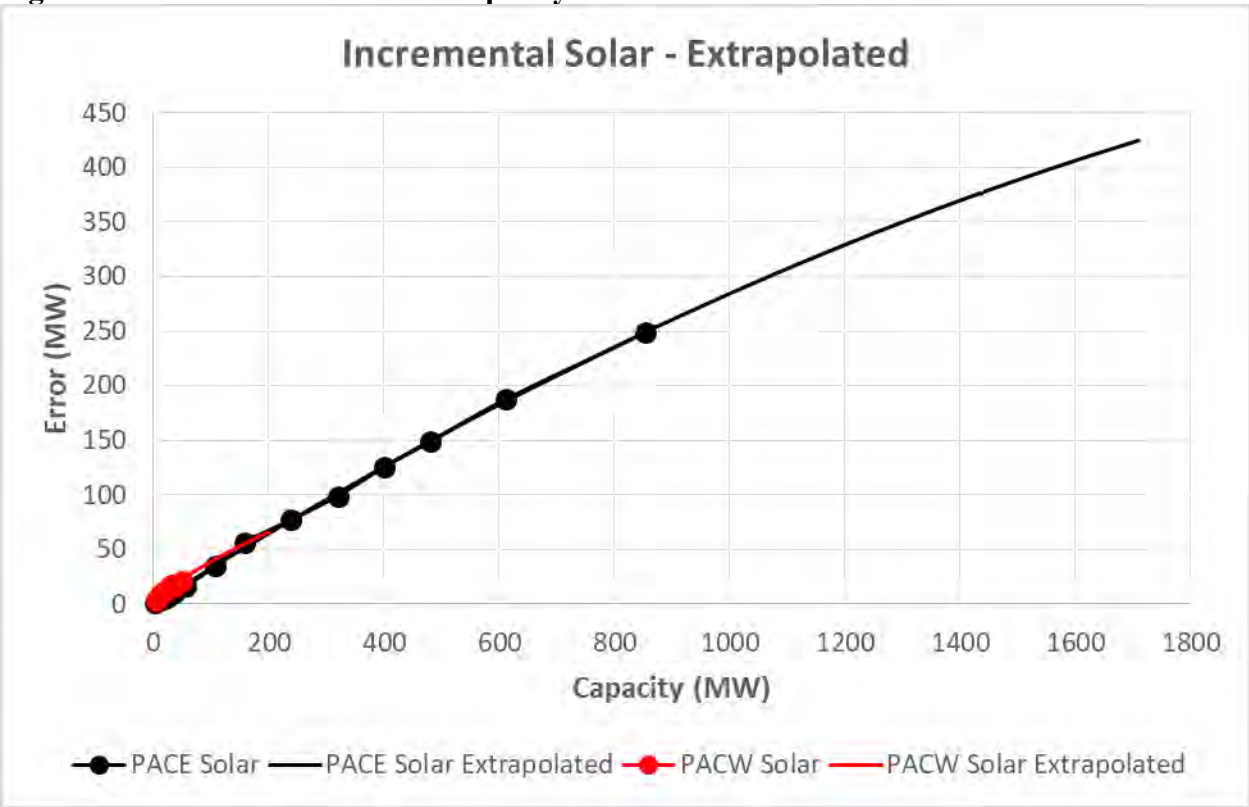


Figure F.13 – Increasing Peak Load-PACE

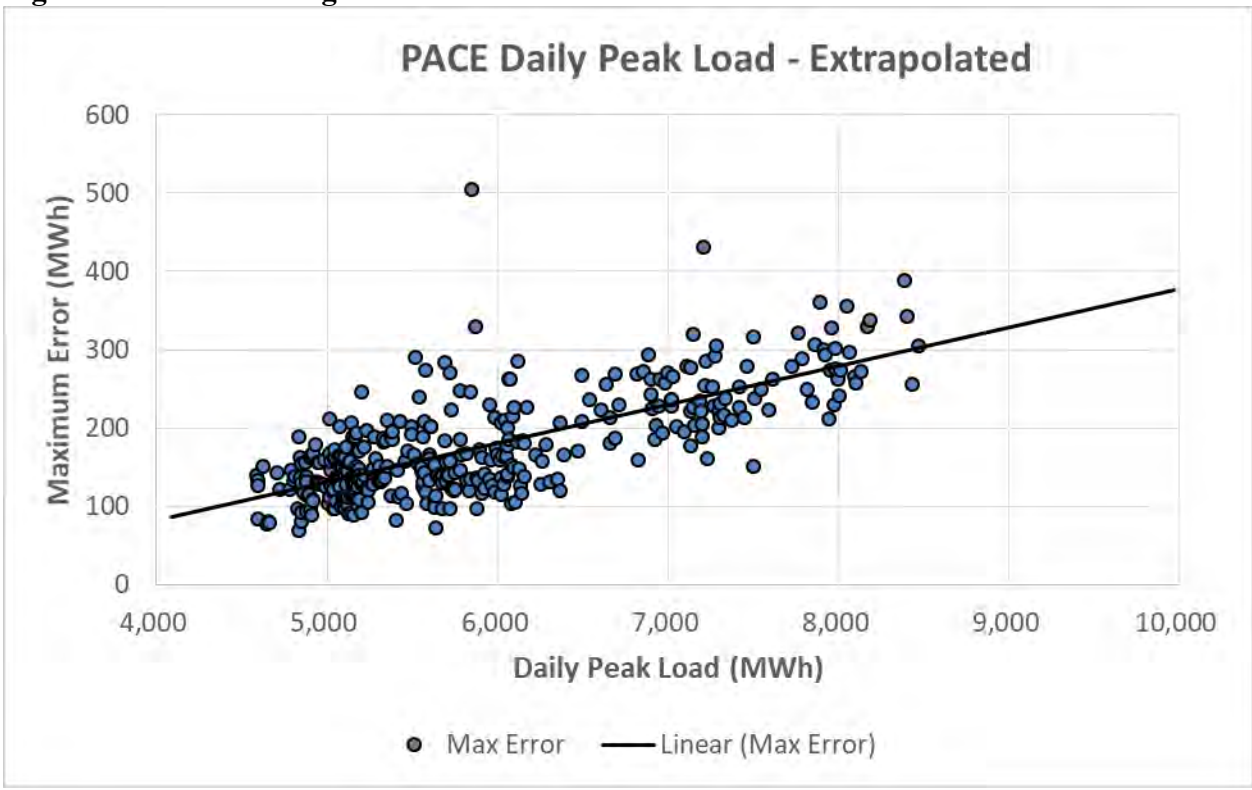
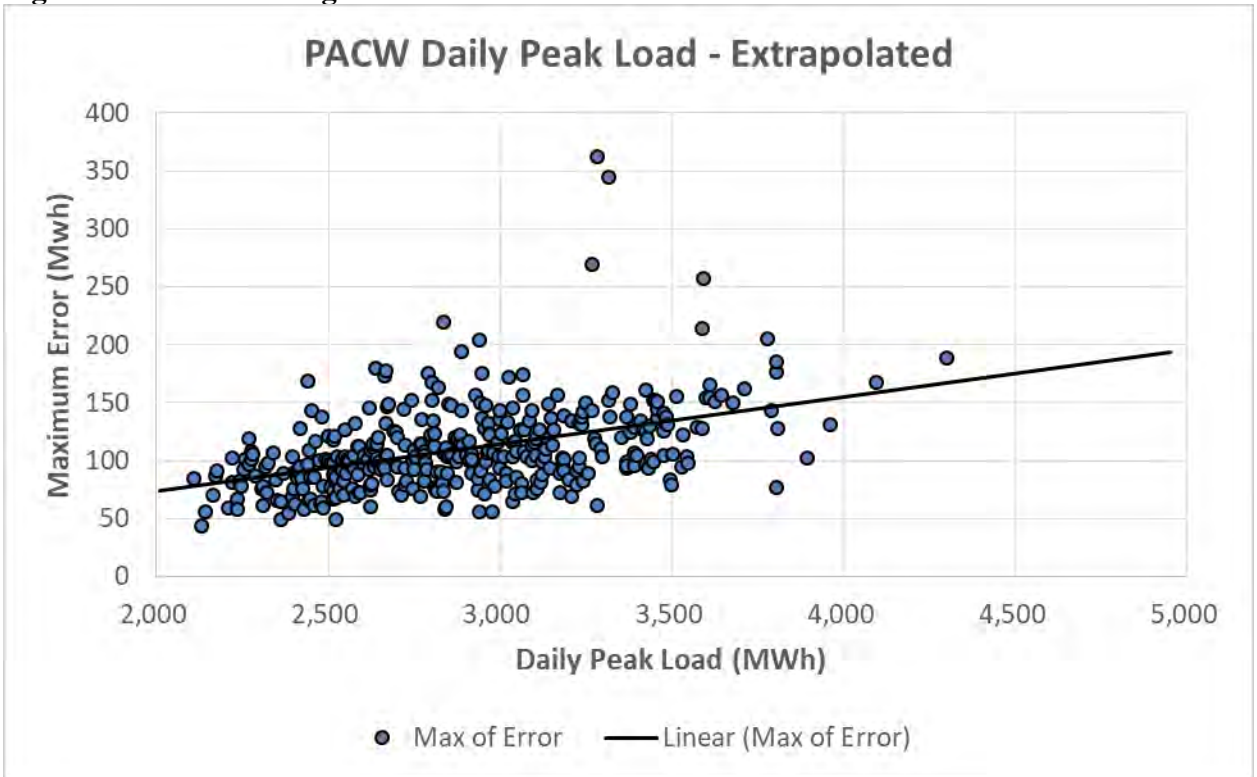


Figure F.14 – Increasing Peak Load-PACW



Portfolio Regulation Reserve Requirements

Overview

A single pool of regulation reserve is held to cover deviations by load, wind, solar, and non-dispatchable generation. Simultaneous large deviations by all classes are unlikely – as a result, this pool of regulation reserve can be smaller than what these classes would require on their own. The reduction in regulation reserve is a result of the diversity of the portfolio of requirements. The most important element in PacifiCorp's portfolio diversity estimate is the system diversity, including EIM benefits, associated with load, wind, solar and Non-VERs during 2017. This diversity reduced reserve requirements by 47 percent. This captures the majority of the regulation reserve requirements today and in likely future scenarios over the near term. However, as PacifiCorp's portfolio evolves over time, the regulation reserve requirements and diversity associated with that portfolio will vary. This section describes how incremental regulation reserve requirements for load, wind, and solar are combined to produce portfolio-specific requirements.

Results

Table F.10 presents the portfolio regulation requirement results for various scenarios. As the wind and solar capacity on PacifiCorp's system increases, regulation requirements increase, but those requirements are partially offset by the increasing diversity of the portfolio. The 2019 base case regulation reserve requirements are 531 MW. By comparison, PacifiCorp's 2017 base case from the 2017 IRP identified regulation reserve requirements of 617 MW.

Table F.10 – Total Regulation Requirement, by Scenario

Case	Portfolio	Wind Capacity (MW)	Solar Capacity (MW)	Regulation Requirement with Diversity (MW)
2017 Base Case	2015 Actuals + Projected Solar	2,757	1,050	617
2019 Base Case	2017 Actuals	2,750	1,021	531
2019 Forecast	2030 Portfolio	3,196	2,201	672
2019 Incr. Wind	2030 Portfolio + 500 MW Wind	3,696	2,201	722
2019 Incr. Solar	2030 Portfolio + 500 MW Solar	3,196	2,701	698

Table F.11 presents a comparison of the regulation reserve requirement results in the current study and the prior study.

Table F.11 - Portfolio Regulation Requirements, Percent of Nameplate/Peak Capacity

Study	Load	Wind	Non-VER	Solar	Notes
2017 FRS Base Case	2.8%	8.9%	2.4%	4.6%	2015 portfolio
2019 FRS Base Case	1.6%	8.4%	3.1%	7.9%	2017 portfolio
Sensitivities:					
Without diversity	3.0%	15.8%	5.7%	14.8%	2017 portfolio
Incremental Wind		10.1%			2030 portfolio: +500 MW wind
Incremental Solar				5.1%	2030 portfolio: +500 MW solar

The 2019 FRS calculates the regulation reserve requirement for the entire portfolio implicitly accounting for diversity among components at various penetration levels. This allows incremental requirements for load, wind and solar to be aligned with the new resource additions being contemplated in the IRP. The incremental requirements for wind are slightly higher than the average requirements for wind when diversity is included, but still well below the stand-alone requirements for wind without diversity. On the other hand, the incremental requirements for solar are less than the average requirements for solar even when diversity is included. These outcomes are reasonable since solar capacity is smaller than wind capacity in the evaluated portfolio, so incremental solar capacity makes the portfolio relatively more diverse.

For the first time, the 2019 FRS accounts for the incremental impact of changes in forecasted load on regulation reserve requirements. For instance, energy efficiency selections (which reduce load), also reduce reserve requirements. The impact of these changes is accounted for within the results reported by the PaR model.

Regulation Reserve Cost

A series of PaR scenarios were prepared to isolate the regulation reserve cost associated with incremental wind and solar capacity additions as discussed below. All studies reflect regulation reserve requirements on an hourly basis.

1. **Base Case**
   The base case portfolio is the same as that used to set the planning reserve margin for the 2019 IRP, as discussed in Appendix I. This case incorporates assumptions consistent with the 2017 IRP Update, updated to reflect current inputs as of August 2018 and without any wind or solar resources additions beyond those that had already been committed at that time. This case was evaluated over the study period 2018-2036.

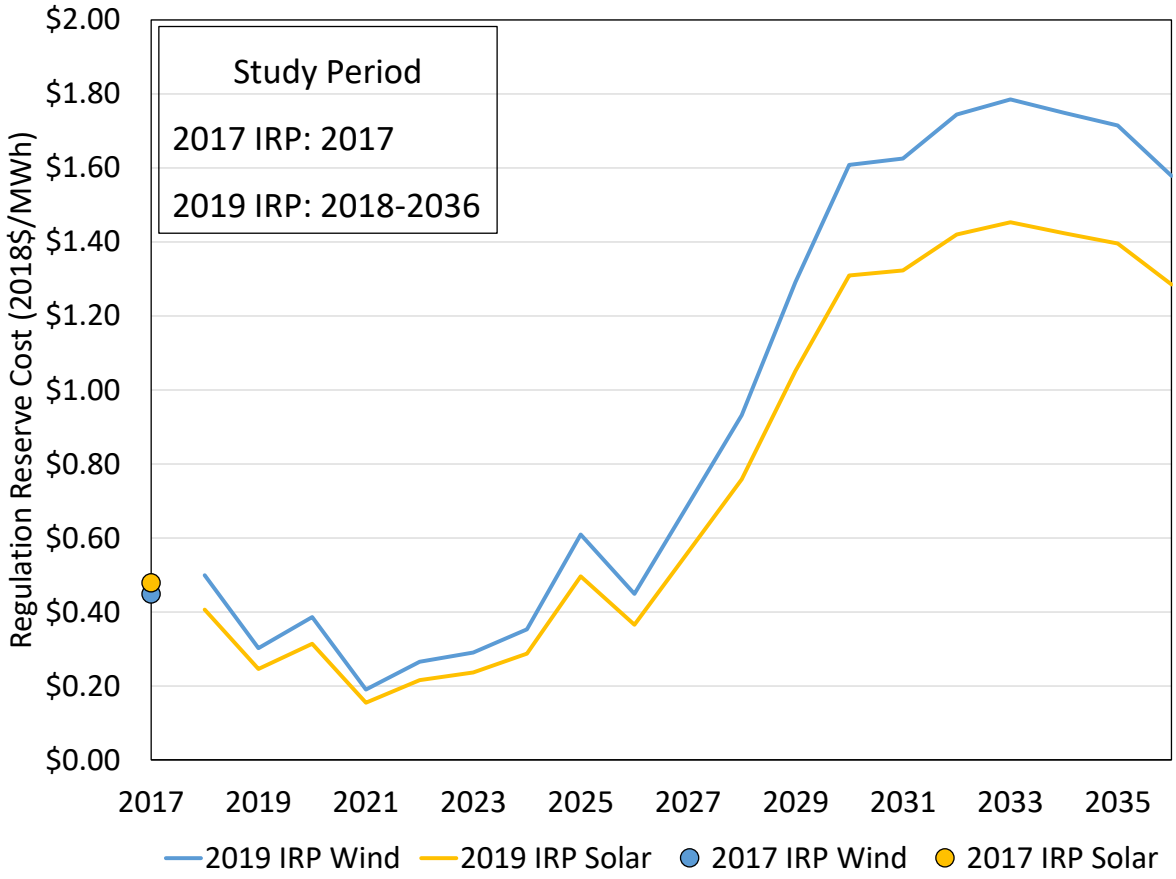
2. **Wind Reserve Case**
   The wind reserve case adds the incremental regulation reserve requirement associated with 500 MW of proxy wind resource additions. Wind capacity increases by 100 MW at each of five locations: Dave Johnston, Goshen, Utah South, Walla Walla, and Yakima. The addition of this wind capacity results increases regulation reserve requirements by an average of 50 MW. This case was evaluated for the study period 2030. Wind integration costs are equal to the increase in system cost in Study 2 relative to Study 1, divided by the incremental wind generation.

3. **Solar Reserve Case**
   The solar reserve case adds the incremental regulation reserve requirement associated with 500 MW of proxy solar resource additions. Solar capacity increases by 250 MW in Utah South and by 125 MW each in Southern Oregon and Yakima. The addition of this solar capacity results increases regulation reserve requirements by an average of 24 MW. This case was evaluated for the study period 2030. Solar integration costs are equal to the increase in system cost in Study 3 relative to Study 1, divided by the incremental solar generation.

4. **50 MW Reserve Case**
   This case includes an additional 50 MW reserve requirement in every hour. This case was evaluated over the study period 2018-2036 and was used to escalate the wind and solar results over time, relative to the 2030 values.

The incremental regulation reserve cost results for wind and solar are shown in Figure F.15. The comparable regulation reserve costs from the 2017 FRS are also shown. While regulation reserve costs in 2018 are comparable to the result in the prior study, the 2019 FRS demonstrates how these costs are expected to vary over time.

Figure F.15 – Incremental Wind and Solar Regulation Reserve Costs



The difference in regulation reserve costs for wind and solar reflects timing differences. Per MWh of generation, the wind reserve obligation is approximately 60 percent higher than the solar obligation; however, the solar obligation is higher during the summer when market prices and marginal reserve costs are typically higher. As a result, per MWh of generation, wind integration costs are only slightly higher than solar integration costs.

The 2019 FRS results are applied in the portfolio development process as an additional cost for proxy wind and solar generation resources available for selection within the SO model. Once the SO model has developed a candidate resource portfolio, the PaR model is used to evaluate portfolio risks. The PaR model inputs include regulation reserve requirements specific to the resource portfolio developed using the SO model, so the costs identified in the 2019 FRS are not applied in the PaR results. Instead, the IRP risk analysis using PaR specifically accounts for both differences in regulation reserve requirements and the resources available to meet those requirements in each portfolio.

When evaluated in PaR, a portfolio will be evaluated on its ability to meet operating reserve requirements, including regulation reserves, but as indicated previously, the SO model does not account for either reserve obligations or the reserve capability that resources can provide. While integration costs have previously been used to account for regulation reserve obligations, for the first time in the 2019 IRP an analogous credit has been applied to highly flexible resources that primarily provide operating reserves. This "operating reserve credit" has been applied to proxy storage, gas peaking units, and Class 1 DSM (interruptible load) that are available for selection

within the SO model. While other resources, such as combined cycle gas plants and renewables, are also capable of providing operating reserves these resources primarily provide energy which the SO model is already accounting for. As a result, no operating reserve credits are applied to these other resources. For a resource that is available throughout the year, such as a gas peaking unit, the operating reserve credit amounts to $50/kw-year (2018$), based on the costs calculated in the 50 MW Reserve Case relative to the Base Case. For resources with limited availability, such as seasonal Class 1 DSM resources or storage combined with wind or solar, the credits are prorated to account for the periods when a resource provides operating reserves.

Flexible Resource Needs Assessment

Overview

In its Order No. 12013 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 2019 through 2038, 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 stochastic simulations run using the Planning and Risk (PaR) model. The regulating reserve requirements are part of the inputs to the PaR 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 2019 IRP: 10-minute spinning reserve requirements, 10-minute non-spinning reserve requirements, and 30-minute regulation reserve requirements. The reserve requirements for PacifiCorp's two balancing authority areas are shown in Table F.12 below.

Table F.12 - Reserve Requirements (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)
2019	193	193	359	93	93	196
2020	194	194	377	94	94	207
2021	194	194	491	96	96	211
2022	196	196	493	97	97	198
2023	199	199	502	97	97	196
2024	202	202	593	98	98	283
2025	203	203	601	99	99	282
2026	203	203	592	99	99	280
2027	205	205	591	100	100	278
2028	207	207	597	101	101	275
2029	208	208	539	101	101	288
2030	210	210	651	102	102	286
2031	212	212	642	102	102	286
2032	214	214	644	102	102	282
2033	215	215	626	102	102	296
2034	216	216	620	102	102	296
2035	217	217	604	101	101	299
2036	219	219	601	101	101	308
2037	220	220	600	101	101	307
2038	221	221	560	101	101	301

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 contracted generation 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 thermal resources, the amount of reserve can be close to the differences between their nameplate capacities and their minimum generation levels. In the current IRP, PacifiCorp's reserve are served not only from existing coal- and gas-fired resources, but also from new gas-fired resources selected in the preferred portfolio.

Table F.13 lists the annual reserve capability from resources in PacifiCorp's East and West balancing authority areas.[20] All the resources included in the calculation are capable of providing all types of reserve. The non-spinning reserve resources under third party contracts are excluded in the calculations. 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.

Table F.13 - Flexible Resource Supply Forecast (MW)

Year	East Supply (10-Minute)	West Supply (10-Minute)	East Supply (30-Minute)	West Supply (30-Minute)
2019	1,843	701	2528	965
2020	1,893	703	2528	967
2021	1,897	684	2472	948
2022	1,913	671	2488	935
2023	1,931	683	2387	947
2024	2,158	965	2613	1262
2025	2,166	963	2621	1260
2026	2,278	963	2734	1260
2027	2,228	964	2734	1261
2028	2,144	1,143	2650	1440
2029	2,268	1,645	2773	1876
2030	2,562	1,645	2987	1876
2031	2,592	1,645	3017	1876
2032	2,604	1,765	3029	1996
2033	2,604	1,884	3029	2016
2034	2,426	1,884	2789	2016
2035	2,441	1,884	2804	2016
2036	2,445	1,988	2808	2120
2037	3,104	2,240	3308	2372
2038	3,601	2,622	3804	2622

Figure F.16 and Figure F.17 graphically display the balances of reserve requirements and capability of spinning reserve resources in PacifiCorp's East and West balancing authority areas

[20] 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 2024 the battery capacity added in the preferred portfolio will exceed of PacifiCorp's current 202.8 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.

respectively. The graphs demonstrate that PacifiCorp's system has sufficient resources to serve its reserve requirements throughout the IRP planning period.

Figure F.16 - Comparison of Reserve Requirements and Resources, East Balancing Authority Area (MW)

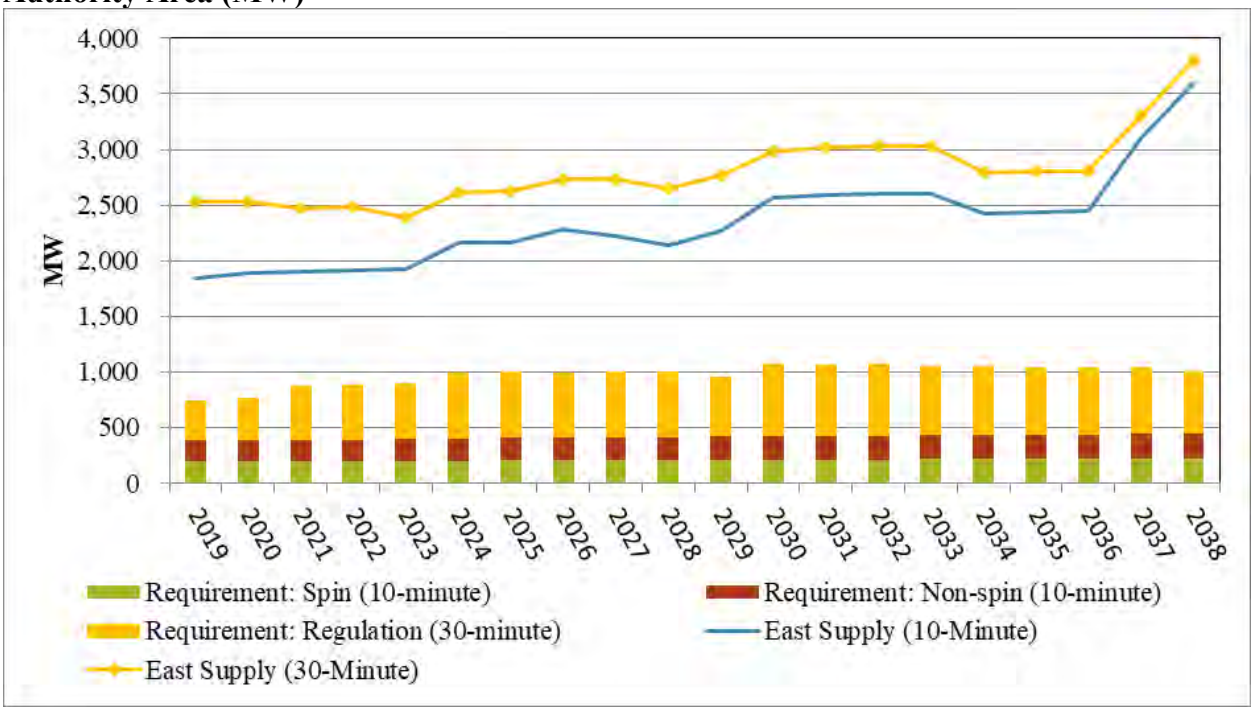
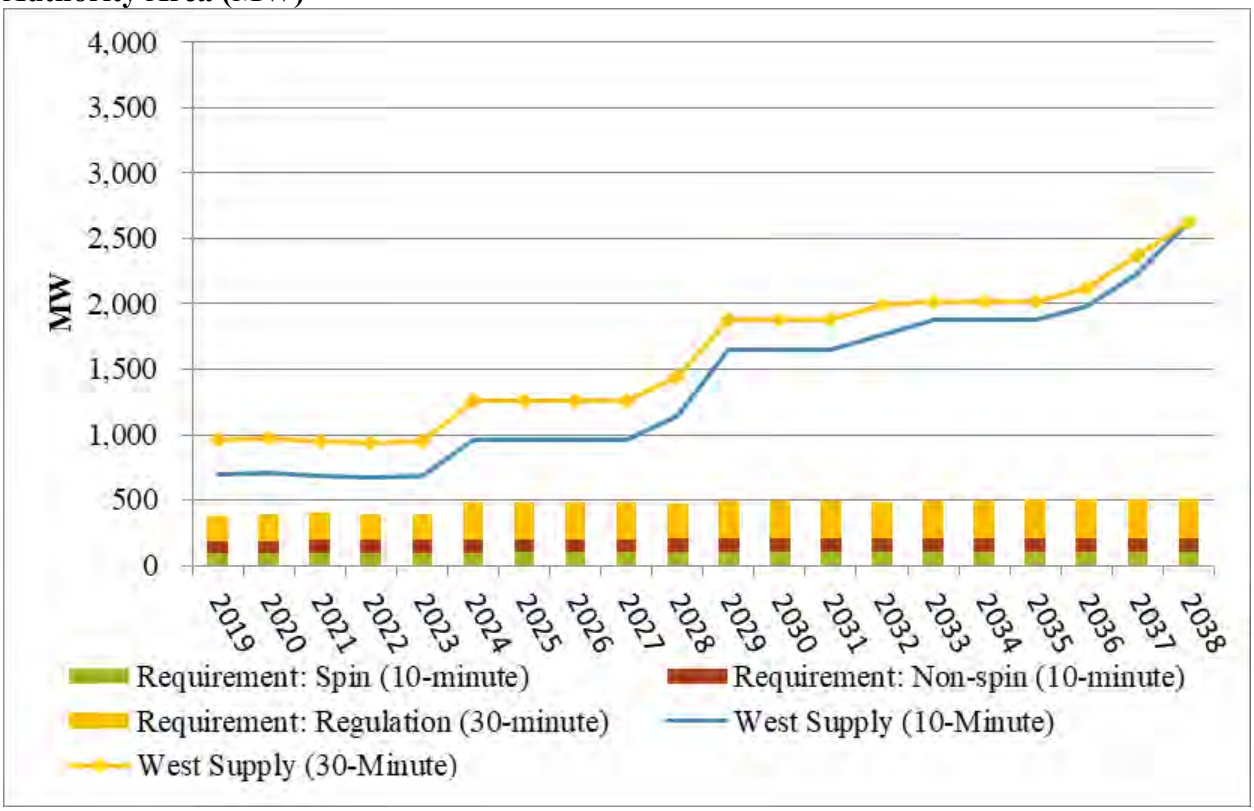


Figure F.17 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



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 2022. 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 the OPUC order, electric vehicle technologies may be able to meet flexible resource needs at some point in the future. However, the electric vehicle technology and market have not developed sufficiently to provide data for the current study. Since this analysis shows no gap between forecasted demand and supply of flexible resources over the IRP planning horizon, this IRP does not evaluate whether electric vehicles could be used to meet future flexible resource needs.

APPENDIX G – PLANT WATER CONSUMPTION

The information provide 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					MWhs Per Year				4-year Average	
Plant Name	Zero Discharge	Cooling Media	2014	2015	2016	2017	4-year Average	2014	2015	2016	2017	Gals/ MWH	GPM/ MW
Chehalis	Yes	Air	150	52	48	54	76	2,543,785	1,090,728	1,395,513	1,748,295	15	0.2
Currant Creek	Yes	Air	92	78	124	116	102	2,498,058	2,257,106	1,474,686	1,193,242	18	0.3
Dave Johnston	No	Water	9,474	9,736	8,864	8,231	9,076	5,183,347	5,140,970	5,088,504	4,519,908	594	9.9
Gadsby	No	Water	367	259	262	100	247	325,677	123,796	120,903	92,814	485	8.1
Hunter	Yes	Water	16,662	16,386	14,225	15,383	15,664	9,098,918	5,988,318	5,503,890	5,399,777	786	13.1
Huntington	Yes	Water	10,240	9,888	9,189	9,653	9,743	6,300,558	9,630,419	8,161,219	8,582,142	389	6.5
Jim Bridger	Yes	Water	23,936	22,493	18,000	19,047	20,869	14,016,315	13,439,341	11,688,747	11,642,810	536	8.9
Lake Side	No	Water	2,960	3,369	3,619	2,698	3,161	4,351,182	4,549,274	5,726,042	3,340,561	229	3.8
Naughton	No	Water	7,484	7,215	6,896	6,927	7,130	4,958,589	4,899,321	4,871,839	4,740,158	477	8.0
Wyodak	Yes	Air	332	228	329	332	305	2,625,183	2,565,603	2,056,439	2,565,053	41	0.7
TOTAL			**71,695**	**69,704**	**61,556**	**62,541**	**66,374**	**51,901,612**	**49,684,876**	**46,087,782**	**43,824,760**	**452**	**7.5**

* Gadsby includes a mix of both Rankine steam units and peaking gas turbines.
** Naughton Unit 3 was rerated in September 2015 from 330 megawatts (MW) to 280 MW. The averages remain as 4-year averages.

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	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Currant Creek	90	84	92	78	124	116
Gadsby	1,059	610	367	259	262	100
Hunter	18,266	17,001	16,662	16,386	14,225	15,383
Huntington	10,423	10,643	10,240	9,888	9,189	9,653
Lake Side	1,693	1,361	2,960	3,369	3,619	2,698
TOTAL	**31,531**	**29,699**	**30,320**	**29,980**	**27,419**	**27,950**

Percent of total water consumption = 42.3

WYOMING PLANTS						
Plant Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Dave Johnston	7,721	8,941	9,474	9,736	8,864	8,231
Jim Bridger	23,977	25,059	23,936	22,493	18,000	19,047
Naughton	8,745	9,622	7,484	7,215	6,896	6,927
Wyodak	322	319	332	228	329	332
TOTAL	**40,765**	**43,941**	**41,225**	**39,672**	**34,089**	**34,537**

Percent of total water consumption = 55.9

Table G.3 – Plant Water Consumption by Fuel Type (acre-feet)

COAL FIRED PLANTS						
Plant Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Dave Johnston	7,721	8,941	9,474	9,736	8,864	8,231
Hunter	18,266	17,001	16,662	16,386	14,225	15,383
Huntington	10,423	10,643	10,240	9,888	9,189	9,653
Jim Bridger	23,977	25,059	23,936	22,493	18,000	19,047
Naughton	8,745	9,622	7,484	7,215	6,896	6,927
Wyodak	322	319	332	228	329	332
TOTAL	**69,454**	**71,585**	**68,127**	**65,946**	**57,503**	**59,573**

Percent of total water consumption = 93.7

NATURAL GAS FIRED PLANTS						
Plant Name	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Currant Creek	90	84	92	78	124	116
Chehalis	55	86	150	52	48	54
Gadsby	1,059	610	367	259	262	100
Lake Side	1,693	1,361	2,960	3,369	3,619	2,698
TOTAL	**2,897**	**2,141**	**3,568**	**3,758**	**4,053**	**2,968**

Percent of total water consumption = 4.6

Table G.4 – Plant Water Consumption for Plants Located in the Upper Colorado River Basin (acre-feet)

Plant Name	2012	2013	2014	2015	2016	2017
Hunter	18,266	17,001	16,662	16,386	14,225	15,383
Huntington	10,423	10,643	10,240	9,888	9,189	9,653
Naughton	8,745	9,622	7,484	7,215	6,896	6,927
Jim Bridger	23,977	25,059	23,936	22,493	18,000	19,047
TOTAL	**61,411**	**62,325**	**58,322**	**55,982**	**48,310**	**51,010**

Percent of total water consumption = 82.0

APPENDIX H – STOCHASTIC PARAMETERS

Introduction

For this IRP, PacifiCorp updated and re-estimated the stochastic parameters provided in the 2017 IRP for use in the Planning and Risk (PaR) model runs.

PaR, 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), PaR 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 PaR 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 PaR 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:

$$\sigma_T = \sigma\sqrt{T}$$

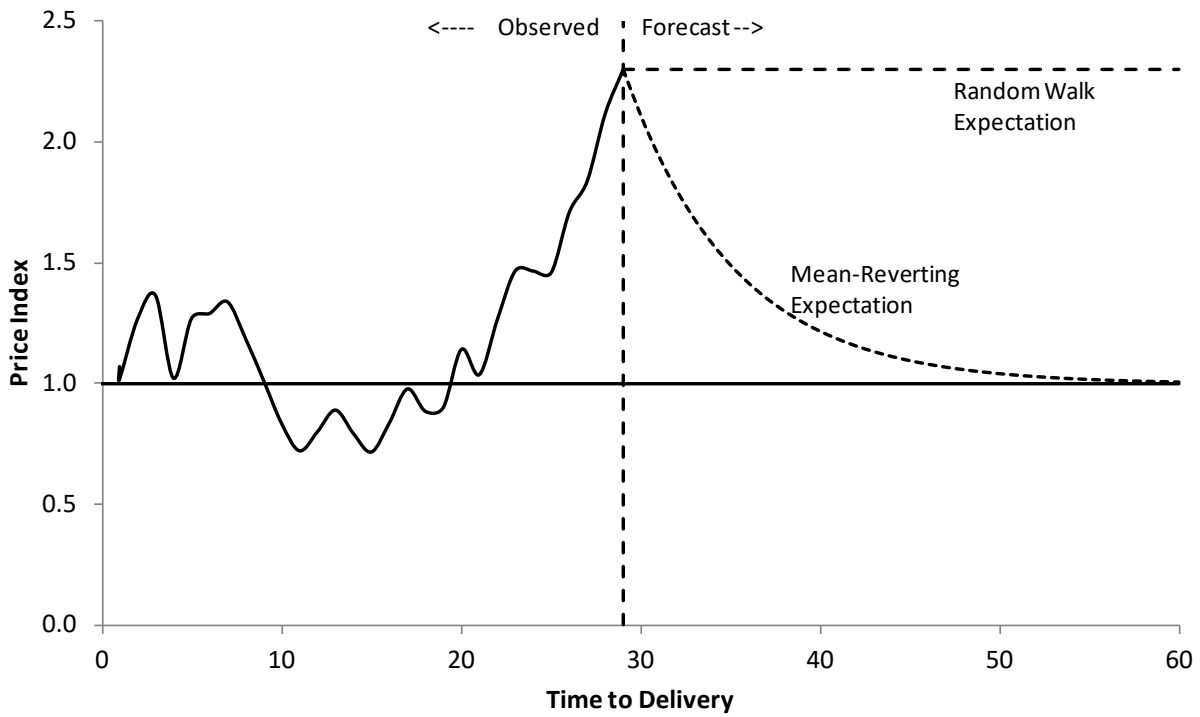
Volatilities are typically quoted on an annual basis but can be specified for any desired time period (T). Suppose the annual volatility of load is two percent. This implies that the standard deviation of the range of possible loads a year from now is two percent, while the standard deviation four years 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.

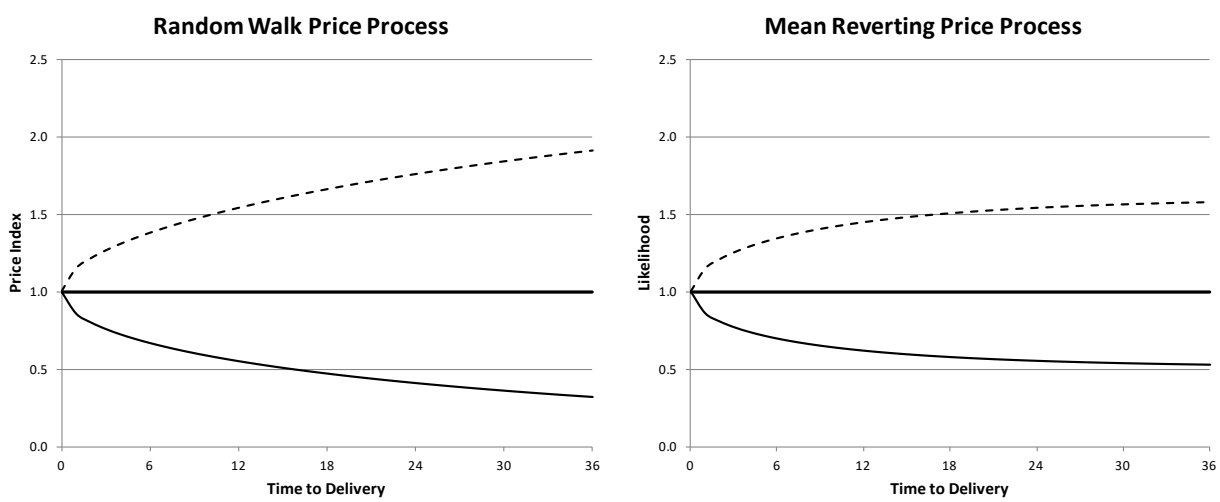
[3] "Standard Deviation" and "Variance" are standard statistical terms describing the spread of possible outcomes. The Variance equals the Standard Deviation squared.

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.

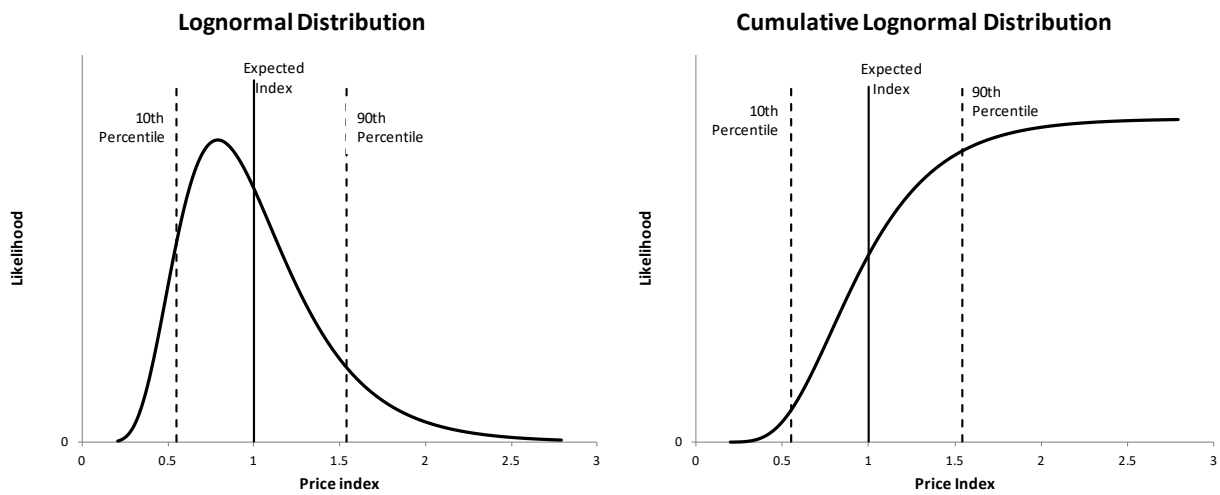
Estimating Short-term Process Parameters

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:

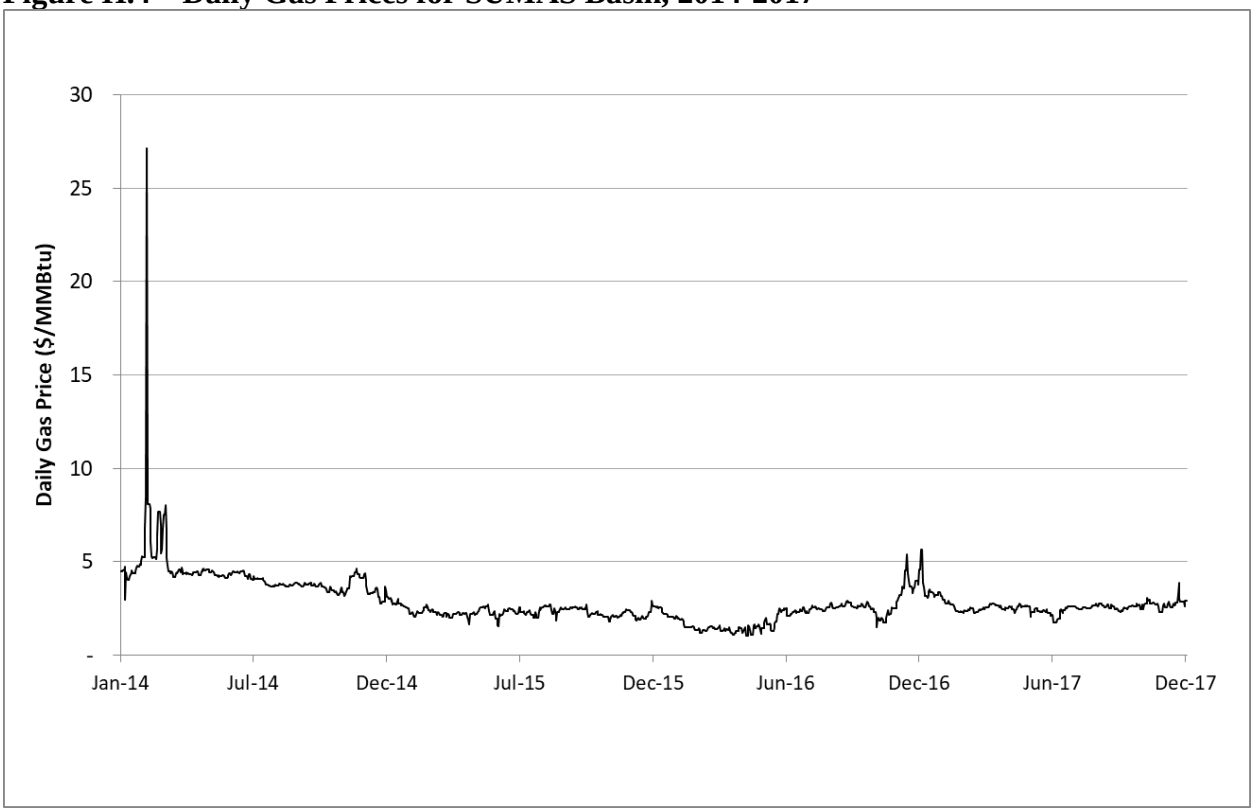
Table H.1 - Seasonal Definitions

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 2014 to 2017 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, 2014-2017



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. In order 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 Average: 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. In order to account for this possible difference in the level of gas prices, the average gas price for each season and year is calculated. For example, Sumas prices in the winter of 2014 average $4.92/MMBtu.

Monthly Average: 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 average price is calculated. For example, February prices in Sumas are 106 percent of the winter average price.

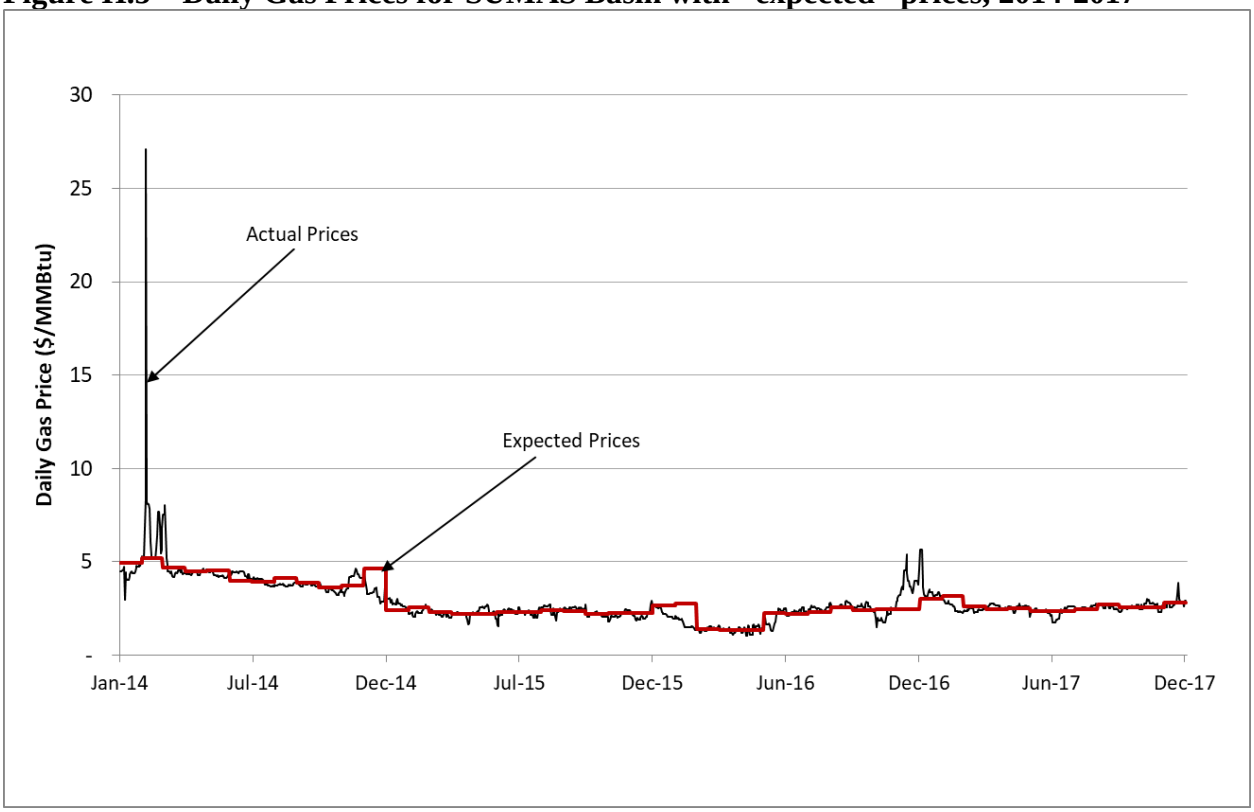
Weekly Shape: Many variables exhibit a distinct shape across the week. For instance, loads and electricity prices are higher during the middle of the week and lower on the weekends. The expected shape of gas prices across the week was calculated and found to be insignificant (expected variation by weekday did not exceed two percent of the weekly average).

These three components – seasonal average, monthly shape, and weekly shape – combine to form an expected price for each day. For example, the expected price of gas in Sumas in February of 2014 was $5.22/MMBtu, the product of the seasonal average and the monthly shape factor

$$Expected\ Gas\ Price\ = Seasonal\ Avg.Price * Monthly\ Shape\ within\ the\ Season$$

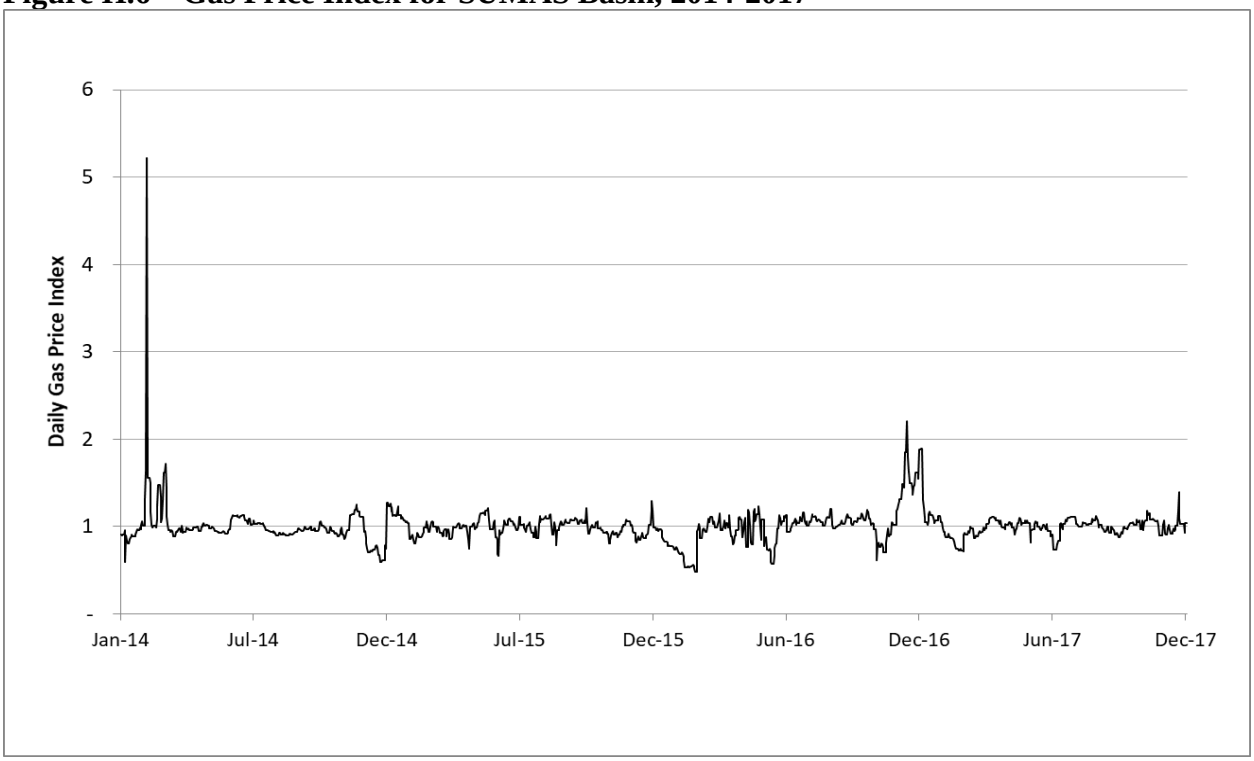
The following chart shows the comparison of the actual Sumas prices with the "expected" prices:

Figure H.5 – Daily Gas Prices for SUMAS Basin with "expected" prices, 2014-2017



Dividing the actual gas prices by the expected prices forms a price index that averages 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, 2014-2017



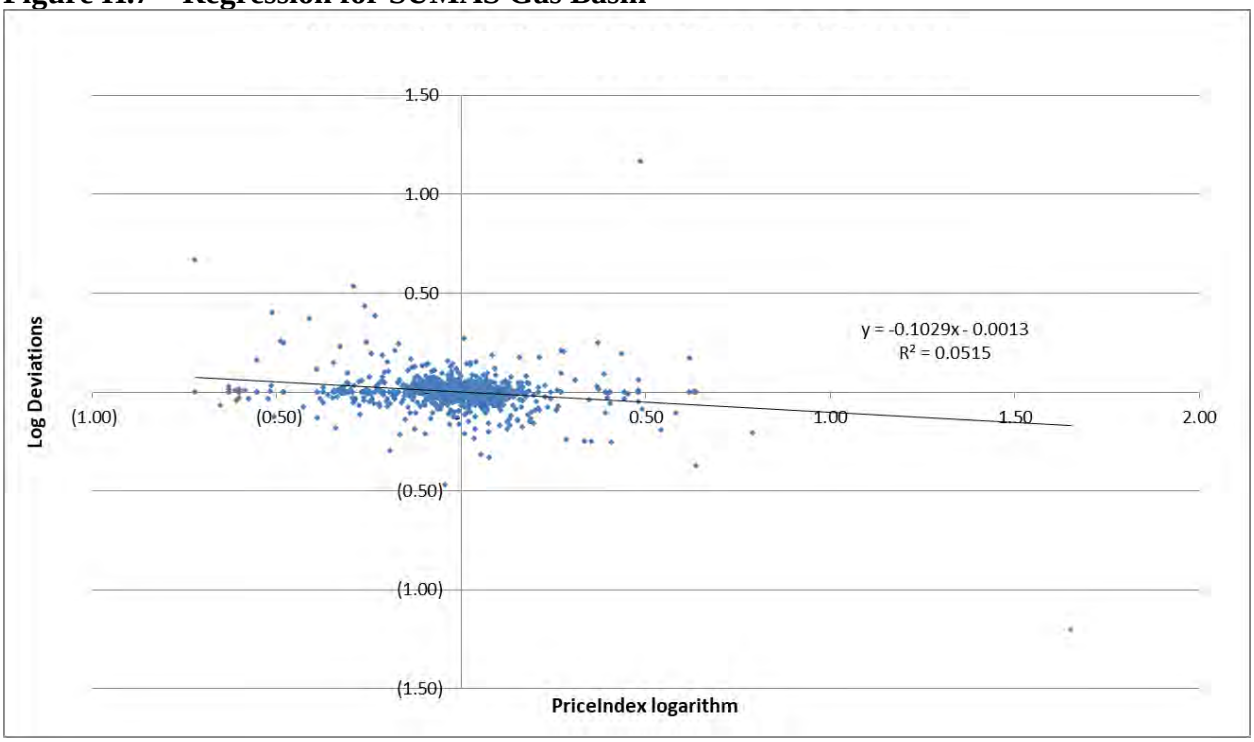
Parameter Estimation – Autoregressive Model

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	11.14%	3.90%	2.46%	3.62%
Daily Mean Reversion Rate	0.110	0.152	0.102	0.071
SUMAS				
Daily Volatility	12.00%	6.07%	4.87%	4.38%
Daily Mean Reversion Rate	0.092	0.265	0.105	0.107

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. Similar to 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, similar to gas prices. The data covers the 2014 through 2017 time 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). In order 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 similar to 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 average, monthly shape and weekly shape. For instance, the expected price for January 2, 2014 in the Four Corners region was $43.12/megawatt hours (MWh). This price incorporates the 2014 winter average price of $39.14/MWh times the monthly shape factor for January of 102 percent and the weekday index for Thursday of 108 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, 2014-2017

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

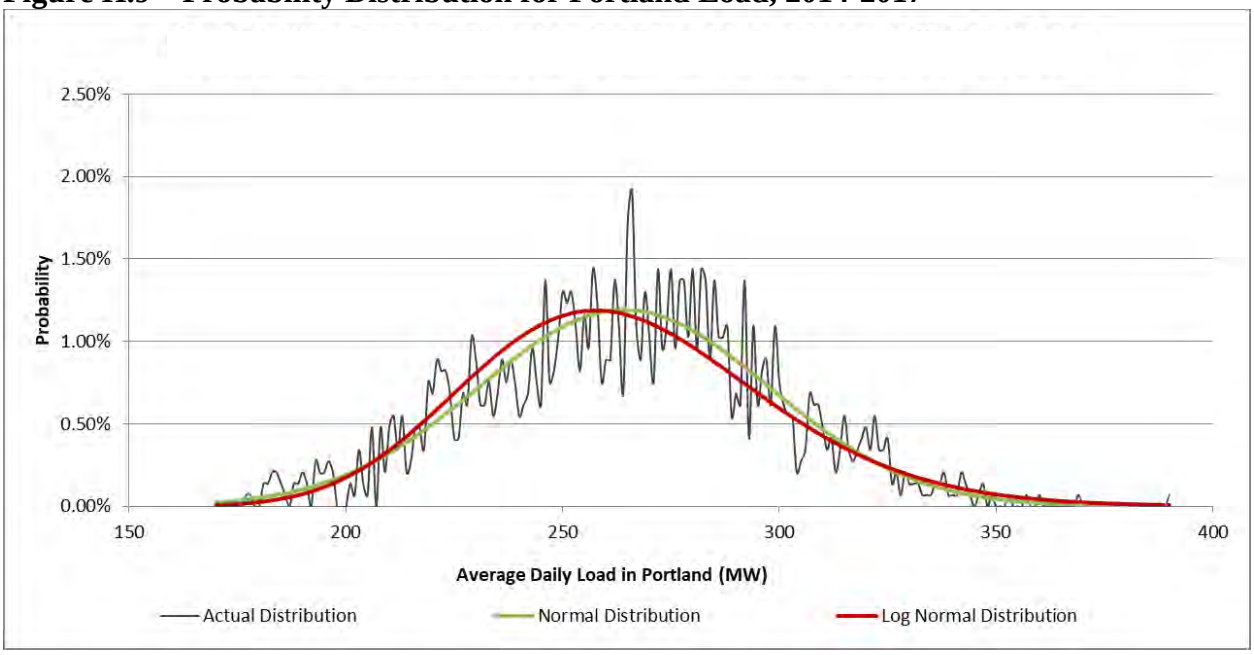
	Winter	Spring	Summer	Fall
Four Corners				
Daily Volatility	9.84%	10.41%	15.47%	10.13%
Daily Mean Reversion Rate	0.125	0.434	0.338	0.370
CA-OR Border				
Daily Volatility	13.44%	26.13%	29.97%	10.19%
Daily Mean Reversion Rate	0.119	0.551	0.463	0.257
Mid-Columbia				
Daily Volatility	16.55%	47.46%	21.28%	10.34%
Daily Mean Reversion Rate	0.140	0.551	0.271	0.279
Palo Verde				
Daily Volatility	9.22%	7.46%	14.08%	9.83%
Daily Mean Reversion Rate	0.110	0.211	0.220	0.415

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.

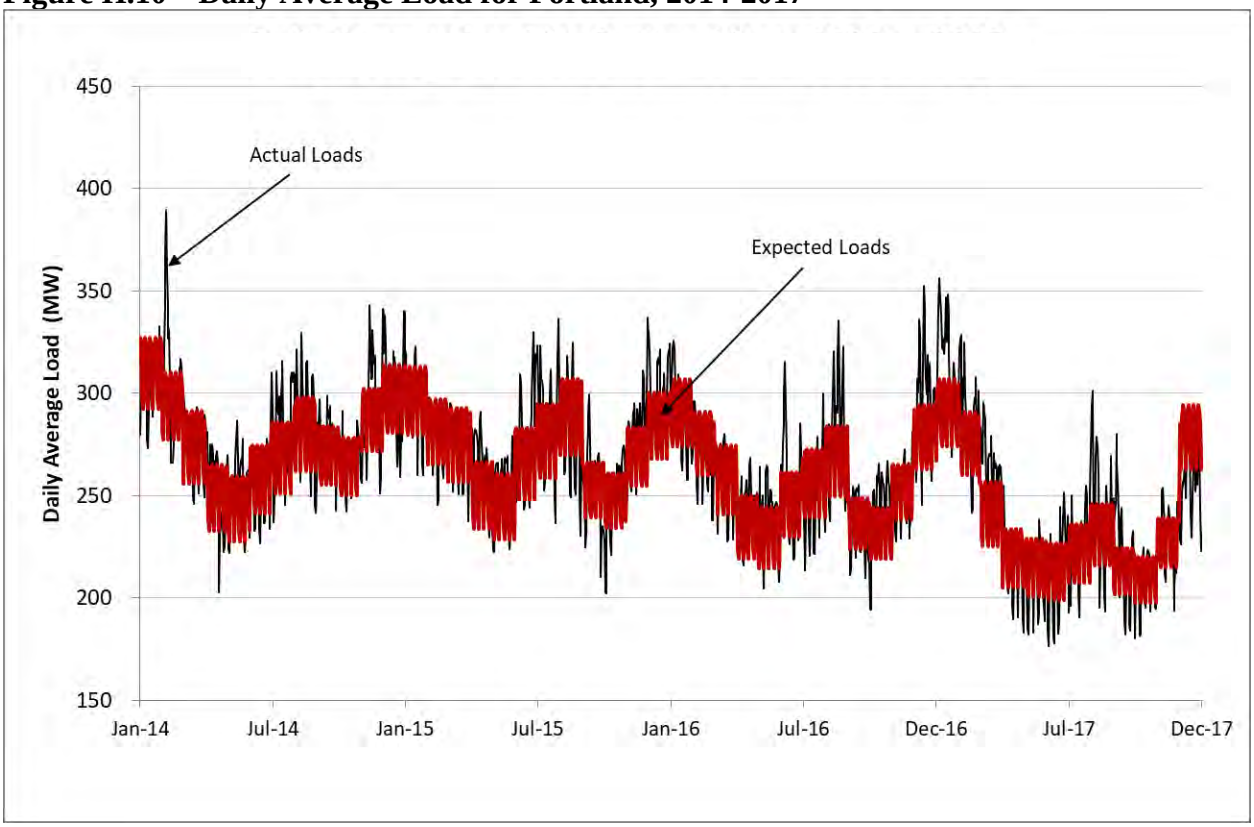
Figure H.9 – Probability Distribution for Portland Load, 2014-2017



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, 2014 in Portland was 324 megawatts (MW). This load incorporates the 2014 winter average load of 305 MW times the monthly shape factor for January of 103 percent and the weekday index for Thursday also of 103 percent. The following chart shows the Portland actual and expected loads over the analysis time period.

Figure H.10 – Daily Average Load for Portland, 2014-2017



Load Uncertainty Parameters:
Uncertainty parameters are calculated for each load region, similar to 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

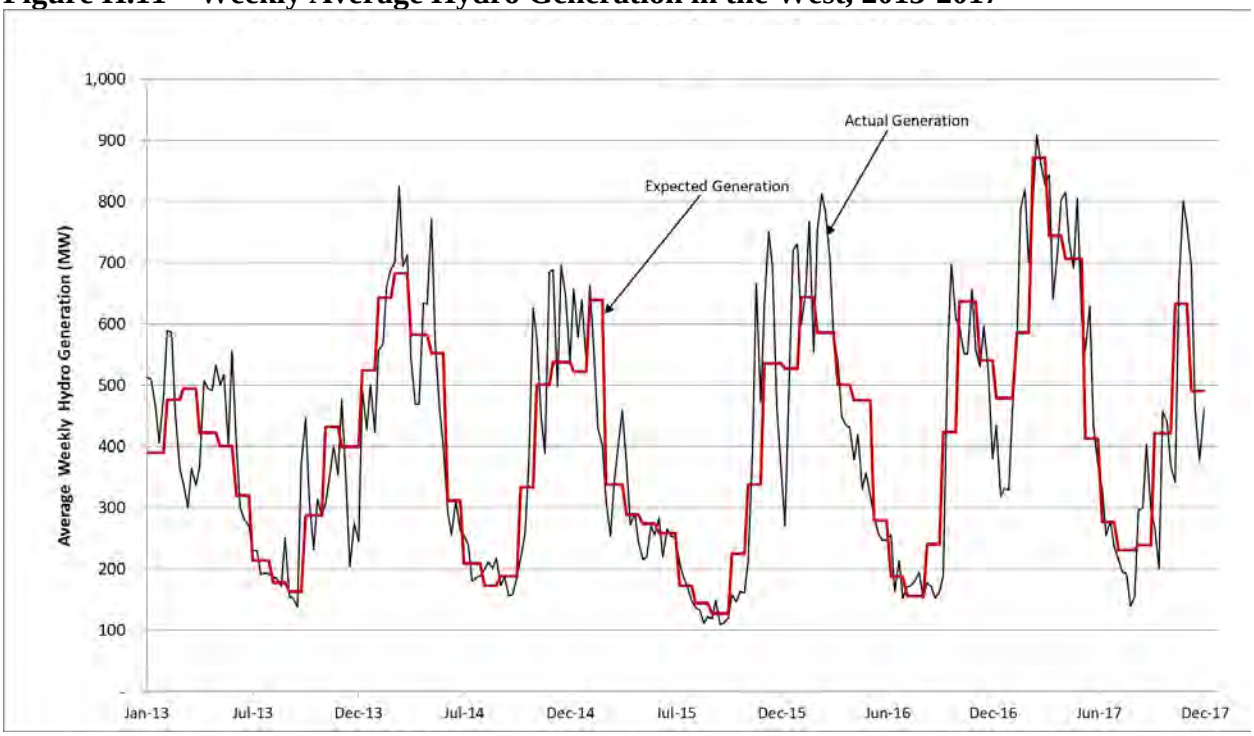
	Winter	Spring	Summer	Fall
California				
Daily Volatility	4.7%	4.2%	3.8%	4.9%
Daily Mean Reversion Rate	0.268	0.218	0.185	0.311
Idaho				
Daily Volatility	3.5%	6.5%	5.1%	4.2%
Daily Mean Reversion Rate	0.153	0.204	0.095	0.218
Portland				
Daily Volatility	3.9%	3.3%	5.0%	3.9%
Daily Mean Reversion Rate	0.177	0.241	0.280	0.242
Oregon Other				
Daily Volatility	4.2%	3.4%	4.2%	4.2%
Daily Mean Reversion Rate	0.182	0.379	0.195	0.253
Utah				
Daily Volatility	2.1%	2.8%	4.5%	3.5%
Daily Mean Reversion Rate	0.363	0.595	0.213	0.249
Washington				
Daily Volatility	5.3%	3.7%	5.0%	4.3%
Daily Mean Reversion Rate	0.181	0.341	0.157	0.203
Wyoming				
Daily Volatility	1.6%	1.8%	1.6%	1.7%
Daily Mean Reversion Rate	0.273	0.254	0.235	0.267

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, average hydro generation is calculated and analyzed on a weekly, rather than daily, basis. Generation is calculated as the average hourly generation across the 168 hours in a week. The hydro analysis covers the 2013 through 2017 time 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, 2013 through January 7, 2013 in the Western Region was 388 MW. This generation incorporates the 2013 winter average generation of 422 MW times the monthly shape factor for January of 92 percent. The following chart shows the western hydro actual and expected generation over the analysis time period.

Figure H.11 – Weekly Average Hydro Generation in the West, 2013-2017



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	21.15%	16.17%	16.78%	30.08%
Weekly Mean Reversion Rate	0.63	0.50	1.51	0.86

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 of the variables. The residual error represents the random portion of the deviation not explained by mean reversion. It is calculated for each time 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:

$$Correlation(X,Y) = \frac{\sum_i^n \left[\left(x_i - x_{avg.}\right) * \left(y_i - y_{avg.}\right)\right]}{\sqrt{\sum_i^n \left(x_i - x_{avg.}\right)^2 * \sum_i^n \left(y_i - y_{avg.}\right)^2}}$$

There are a few things to note about the correlation calculations. First, correlation data must always be organized so that the same time 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

SHORT-TERM WINTER CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	89%	63%	35%	38%	66%	3%	14%	20%	13%	10%	24%	10%	5%
SUMAS	89%	100%	57%	40%	42%	61%	5%	17%	17%	14%	8%	22%	12%	6%
4C	63%	57%	100%	58%	57%	83%	10%	15%	27%	27%	20%	29%	12%	3%
COB	35%	40%	58%	100%	94%	61%	14%	19%	30%	37%	21%	43%	19%	6%
Mid-C	38%	42%	57%	94%	100%	59%	14%	21%	36%	40%	25%	46%	24%	2%
PV	66%	61%	83%	61%	59%	100%	10%	10%	24%	23%	17%	29%	12%	3%
CA	3%	5%	10%	14%	14%	10%	100%	24%	27%	66%	35%	32%	21%	-4%
ID	14%	17%	15%	19%	21%	10%	24%	100%	23%	30%	32%	31%	34%	-11%
Portland	20%	17%	27%	30%	36%	24%	27%	23%	100%	67%	48%	65%	30%	-4%
OR Other	13%	14%	27%	37%	40%	23%	66%	30%	67%	100%	49%	65%	29%	3%
UT	10%	8%	20%	21%	25%	17%	35%	32%	48%	49%	100%	49%	38%	-8%
WA	24%	22%	29%	43%	46%	29%	32%	31%	65%	65%	49%	100%	34%	15%
WY	10%	12%	12%	19%	24%	12%	21%	34%	30%	29%	38%	34%	100%	-2%
Hydro	5%	6%	3%	6%	2%	3%	-4%	-11%	-4%	3%	-8%	15%	-2%	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 -11 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

SHORT-TERM SPRING CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	55%	20%	10%	7%	33%	7%	7%	2%	0%	7%	5%	1%	3%
SUMAS	55%	100%	6%	8%	7%	13%	10%	2%	4%	3%	-5%	8%	3%	2%
4C	20%	6%	100%	34%	36%	62%	0%	7%	7%	6%	15%	12%	11%	-9%
COB	10%	8%	34%	100%	86%	39%	13%	-3%	24%	21%	8%	31%	13%	0%
Mid-C	7%	7%	36%	86%	100%	31%	13%	1%	26%	21%	11%	29%	15%	0%
PV	33%	13%	62%	39%	31%	100%	3%	16%	17%	14%	24%	24%	15%	-3%
CA	7%	10%	0%	13%	13%	3%	100%	18%	20%	55%	17%	33%	9%	-1%
ID	7%	2%	7%	-3%	1%	16%	18%	100%	6%	20%	43%	20%	17%	-17%
Portland	2%	4%	7%	24%	26%	17%	20%	6%	100%	63%	22%	57%	27%	11%
OR Other	0%	3%	6%	21%	21%	14%	55%	20%	63%	100%	31%	65%	23%	10%
UT	7%	-5%	15%	8%	11%	24%	17%	43%	22%	31%	100%	25%	30%	-11%
WA	5%	8%	12%	31%	29%	24%	33%	20%	57%	65%	25%	100%	24%	18%
WY	1%	3%	11%	13%	15%	15%	9%	17%	27%	23%	30%	24%	100%	-1%
Hydro	3%	2%	-9%	0%	0%	-3%	-1%	-17%	11%	10%	-11%	18%	-1%	100%

Similarly, the spring season shows a very low correlation of nine 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

SHORT-TERM SUMMER CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	45%	5%	0%	2%	0%	0%	5%	-3%	-3%	8%	4%	-4%	-1%
SUMAS	45%	100%	5%	5%	10%	1%	-1%	-5%	3%	0%	-4%	5%	-7%	0%
4C	5%	5%	100%	27%	29%	52%	21%	11%	17%	17%	21%	18%	13%	-4%
COB	0%	5%	27%	100%	85%	44%	15%	16%	32%	28%	9%	28%	8%	7%
Mid-C	2%	10%	29%	85%	100%	51%	22%	16%	48%	45%	15%	38%	4%	4%
PV	0%	1%	52%	44%	51%	100%	22%	16%	28%	25%	25%	20%	16%	5%
CA	0%	-1%	21%	15%	22%	22%	100%	39%	33%	55%	30%	47%	14%	-3%
ID	5%	-5%	11%	16%	16%	16%	39%	100%	18%	27%	47%	26%	22%	5%
Portland	-3%	3%	17%	32%	48%	28%	33%	18%	100%	80%	11%	68%	-5%	16%
OR Other	-3%	0%	17%	28%	45%	25%	55%	27%	80%	100%	20%	78%	1%	9%
UT	8%	-4%	21%	9%	15%	25%	30%	47%	11%	20%	100%	24%	48%	-7%
WA	4%	5%	18%	28%	38%	20%	47%	26%	68%	78%	24%	100%	4%	9%
WY	-4%	-7%	13%	8%	4%	16%	14%	22%	-5%	1%	48%	4%	100%	-11%
Hydro	-1%	0%	-4%	7%	4%	5%	-3%	5%	16%	9%	-7%	9%	-11%	100%

In the summer season, zero 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

SHORT-TERM FALL CORRELATIONS

	K-O	SUMAS	4C	COB	Mid-C	PV	CA	ID	Portland	OR Other	UT	WA	WY	Hydro
K-O	100%	73%	14%	15%	12%	13%	15%	6%	11%	19%	11%	17%	7%	2%
SUMAS	73%	100%	10%	13%	13%	7%	28%	10%	25%	33%	24%	32%	22%	4%
4C	14%	10%	100%	36%	22%	53%	19%	10%	23%	20%	21%	21%	4%	-4%
COB	15%	13%	36%	100%	78%	63%	9%	2%	24%	16%	24%	19%	3%	-2%
Mid-C	12%	13%	22%	78%	100%	44%	10%	8%	22%	18%	19%	22%	3%	-4%
PV	13%	7%	53%	63%	44%	100%	9%	9%	16%	7%	20%	9%	-5%	1%
CA	15%	28%	19%	9%	10%	9%	100%	29%	47%	70%	34%	54%	38%	-5%
ID	6%	10%	10%	2%	8%	9%	29%	100%	19%	25%	41%	25%	24%	-12%
Portland	11%	25%	23%	24%	22%	16%	47%	19%	100%	78%	45%	73%	39%	12%
OR Other	19%	33%	20%	16%	18%	7%	70%	25%	78%	100%	45%	83%	47%	7%
UT	11%	24%	21%	24%	19%	20%	34%	41%	45%	45%	100%	44%	44%	-1%
WA	17%	32%	21%	19%	22%	9%	54%	25%	73%	83%	44%	100%	42%	9%
WY	7%	22%	4%	3%	3%	-5%	38%	24%	39%	47%	44%	42%	100%	4%
Hydro	2%	4%	-4%	-2%	-4%	1%	-5%	-12%	12%	7%	-1%	9%	4%	100%

In the fall, a very low correlation of three 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 - PLANNING RESERVE MARGIN STUDY

Introduction

The planning reserve margin (PRM), measured as a percentage of coincident system peak load, is a parameter used in resource planning to ensure there are adequate resources to meet forecasted load over time. PacifiCorp selects a PRM for use in its resource planning by studying the relationship between cost and reliability among eight different PRM levels, accounting for variability and uncertainty in load and generation resources.[1] Costs include capital and run-rate fixed costs for new resources required to achieve eight different PRM levels, ranging from 11 to 18 percent, along with system production costs (fuel and non-fuel variable operating costs, contract costs, and market purchases). In analyzing reliability, PacifiCorp performed a stochastic loss of load study using the Planning and Risk (PaR) production cost simulation model to calculate the following reliability metrics for each PRM level:

- Expected Unserved Energy (EUE): Measured in gigawatt-hours (GWh), EUE reports the expected (mean) amount of load that exceeds available resources over the course of a given year. EUE measures the magnitude of reliability events, but does not measure frequency or duration.
- Loss of Load Hours (LOLH): LOLH is a count of the expected (mean) number of hours in which load exceeds available resources over the course of a given year. A LOLH of 2.4 hours per year equates to one day in 10 years, a common reliability target in the industry. LOLH measures the duration of reliability events, but does not measure frequency or magnitude.
- Loss of Load Events (LOLE): LOLE is a count of the expected (mean) number of reliability events over the course of a given year. An LOLE of 0.1 events per year equates to one event in 10 years, a common reliability target in the industry. LOLE measures the frequency of reliability events, but does not measure magnitude or duration.

PacifiCorp's loss of load study results reflect its participation in the Northwest Power Pool (NWPP) reserve sharing agreement. This agreement allows a participant to receive energy from other participants within the first hour of a contingency event, defined as an event when there is an unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. PacifiCorp's participation in the NWPP reserve sharing agreement improves reliability at a given PRM level. Upon evaluating the relationship between cost and reliability in its PRM study, PacifiCorp will continue to use a 13 percent target PRM in its resource planning.

Objective

The purpose of the PRM is to ensure that Integrated Resource Plan (IRP) portfolios a) meet customer load b) while maintaining operating reserves, c) meeting a one day in ten year reliability target, d) at a low reasonable cost. The 2019 IRP PRM selection is made by analyzing:

[1] Costs and reliability metrics are calculated for eight different PRM levels, ranging from 11 to 18 percent. Comparative analysis among each PRM is performed for seven different PRM levels by comparing the cost and reliability results from PRM levels ranging between 11 and 18 percent to those from the 10 percent PRM.

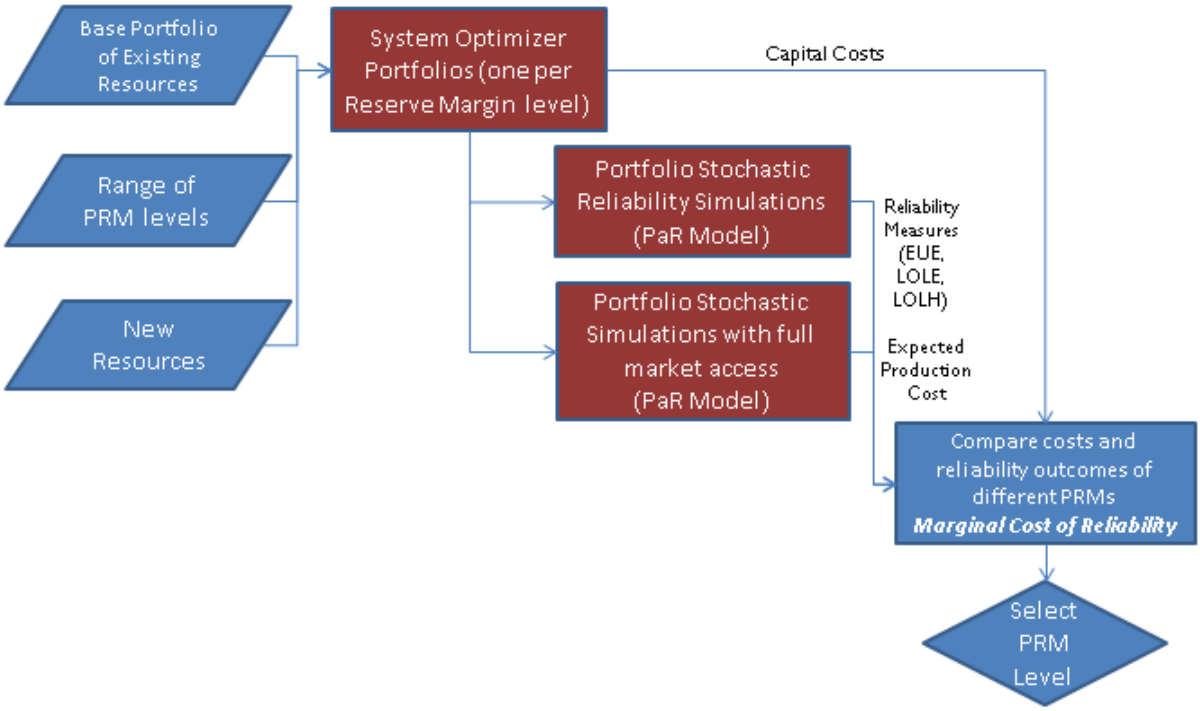
- Relationships between reliability modeling and production cost modeling results
- PRM cases range from 11 to 18 percent in the target year (2030)
- Bookend cases will be run for years 2022 and 2036

The target year of 2030 is selected based on a preliminary assessment aligned with significant assumed retirements; bookend years were developed as a check on this assumption.

Methodology

Figure I.1 shows the workflow used in PacifiCorp's PRM study. The four basic modeling steps in the workflow include: (1) using the System Optimizer (SO) model, produce resource portfolios among seven different PRM levels ranging between 11 and 18 percent; (2) using PaR, produce reliability metrics for each resource portfolio; (3) using PaR, produce system stochastic variable production costs with full market access for each resource portfolio; (4) produce the marginal cost of reliability using outcomes of different PRM levels, (5) select PRM level.

Figure I.1 - Workflow for Planning Reserve Margin Study



Development of Resource Portfolios

The SO model is used to produce resource portfolios assuming PRM levels ranging between 11 and 18 percent. The SO model optimizes expansion resources over a 20-year planning horizon to meet peak load inclusive of the PRM applicable to each case.

Consistent with the 2017 IRP, as the PRM level increases additional resources are added to the portfolio. Resource options used in this step of the workflow include demand-side management (DSM), gas-fired combined cycle combustion turbines (CCCT), gas-fired simple cycle combustion turbines (SCCT), renewable resources and front office transactions (FOTs).

Updated Assumptions

Front Office Transactions (FOT)
FOTs are considered as a resource expansion option in this phase of the workflow. FOTs are proxy resources used in the IRP portfolio development process that represent firm forward short-term market purchases for summer and winter on-peak delivery, which coincides with the time of year and time of day in which PacifiCorp observes its coincident system peak load.

These proxy resources are a reasonable representation of firm market purchases when performing comparative analysis of different resource portfolios to arrive at a preferred portfolio in the IRP.

The front office transaction reserve credit, previously calculated at six percent of load, has been lowered to three percent, reflecting the three percent of load/three percent of generation requirement which is new this IRP cycle.

Market Purchases
The SO model planning limit for FOT selection as a capacity resource in the 2019 IRP is 1,425 megawatt (MW) in both summer and winter. In past IRPs, PaR has allowed for market balancing purchases up to transmission limits for the purpose of valuing portfolios in all months of the year. As a consequence, in the 2017 IRP, all PRM levels met PaR loss of load hour (LOLH) requirements, relying on market purchases.

In the 2019 IRP, PaR market purchases are restricted to FOT limits in all months of the PRM models. This change makes PaR reliability measures consistent with market reliance assumptions, and allows the impact of market purchase reliance to be assessed in reliability analysis.

Planning Capacity Factor (PCF)
The planning capacity factor for DSM, solar and natural gas resources has been updated for the 2019 IRP Planning Reserve Margin Study, based on updated analysis and the latest information.

<u>Demand Response (Class 1 DSM)</u>
Demand Response contracts define limits on the number of interruptible hours per day and hours per year reduce capacity contribution. In order to represent these limitations accurately, the capacity factor (CF) approximation method has been applied to each demand response program. PCF is consequently reduced by a weighted average of 11 percent, ranging from -2 to -22 percent by program. Also, in alignment with actual practice, summer demand response availability has been expanded to June through September and winter, and winter demand response has been expanded to October through December.

<u>Energy Efficiency (Class 2 DSM)</u>
Similar to demand response, energy efficiency has limitations on hours per day and hours per year, restricting capacity contribution. Taking these limitations into account reduces energy efficiency PCF by a weighted average of 15 percent, ranging from -24 to +13 percent by bundle.

<u>Solar</u>
In response to rapid increases in solar penetration, PacifiCorp assessed a 2030 solar resource PCF, measured relative to a case with no solar. East solar has an overall effective capacity contribution of 29.3 percent, down from 37.9 percent for fixed and 59.7 percent for tracking. West solar has an

overall effective capacity contribution of 35.6 percent, down from 53.9 percent for fixed and 64.8 percent for tracking.

Natural Gas
Past IRPs have relied on monthly average temperature impacts. The 2019 IRP uses a summer peak temperature to improve PCF consistency with peak capacity needs.

Upfront capital and run-rate fixed costs from each portfolio are recorded and used later in the workflow where the relationship between cost and reliability is analyzed. Resources from each portfolio are used in the subsequent workflow steps where reliability metrics and production costs are produced in PaR.

Development of Reliability Metrics

The PaR model is used to produce reliability metrics for each of the resource portfolios developed assuming PRM levels ranging between 11 and 18 percent. PaR is a production cost simulation model, configured to represent PacifiCorp's integrated system that uses Monte Carlo random sampling of stochastic variables to produce a distribution of system operation. For this step in the workflow, reliability metrics are produced from a 500-iteration PaR simulation with Monte Carlo draws of stochastic variables that affect system reliability—load, hydro generation, and thermal unit outages. As discussed above, system balancing hourly purchases are enabled to capture the contribution of firm market purchases to system reliability. The PaR reliability studies are used to report instances where load exceeds available resources, including system balancing hourly purchases. Reported EUE measures the stochastic mean volume of instances where load exceeds available resources, and is measured in GWh. EUE measures the magnitude of reliability events. Reported LOLH is a count of the stochastic mean hours in which load exceeds available resources. LOLH measures the duration of reliability events. Reported LOLE is a count of the stochastic mean events in which load exceeds available resources. LOLE is a measure of the frequency of reliability events.

Each of the reliability metrics described above is adjusted to account for PacifiCorp's participation in the NWPP reserve sharing agreement, which allows a participant to receive energy from other participants within the first hour of a contingency event. PacifiCorp accounts for the NWPP reserve sharing agreement by assuming the first hour of any event is covered and removed in the tabulation of EUE, LOLH and LOLE measures. NWPP participation reduces each of these measures by roughly half.

For PaR, the contribution of firm market purchases are removed and instead include system balancing hourly purchases that cover the firm market purchases, limited by transmission and market depth limits, for the reliability metrics.

Development of System Variable Production Costs

In addition to using PaR to develop reliability metrics, PaR is also used to produce system variable production operating costs for each of the resource portfolios developed assuming PRM levels ranging between 11 and 18 percent. For PaR's system variable production cost runs, its Monte Carlo sampling of stochastic variables is expanded to include natural gas and wholesale market prices in addition to load, hydro generation, and thermal unit outages. At this step, the stochastic treatment of market prices is key given its influence on the economic dispatch of system resources,

cost of system balancing purchases, and revenues from system balancing sales. In this step, full market access is included for the simulation. The stochastic mean of system variable costs is added to the upfront capital and run-rate fixed costs from each portfolio so that total portfolio costs are captured for each PRM level.

Selection of the Planning Reserve Margin

Using the incremental cost of reliability analysis, guided by additional measures detailed below, the PRM level is selected for use in the 2019 IRP.

Results

Resource Portfolios

Table I.1 shows new resources added to the portfolio for the summer at PRM levels ranging between 11 and 18 percent. Each portfolio includes FOTs ranging from 1,312 MW to 1,416 MW. In the summer, FOTs don't vary much as all PRMs are relying on most of the FOT limit during the peak. Natural gas resource additions escalate from 1,264 MW of resource to 1,865 MW across the PRM studies as the margin increases. DSM resource additions range between 218 MW and 891 MW.

In the summer, each 1 percent PRM increases system capacity by roughly 100MW. At each odd-numbered PRM increase, the model adds an additional single-cycle gas resource, partially offset by a reduction in FOTs and interruptible load selections. This trade-off occurs because new gas resources are added in blocks indicative of a typical plant size (i.e. the model cannot add a two MW SCCT plant), and thus the additions in each separate resource category do not move uniformly with an increase in the PRM.

Table I.1 – Summer Expansion Resource Additions by PRM

PRM (%)	Capacity at Summer Peak (MW)					
	DSM		FOT	Natural Gas	Geo-Thermal/ Other	Total
	Energy Efficiency	Demand Response				
11	824	240	1,313	1,264	31	3,672
12	821	219	1,416	1,287	31	3,775
13	830	244	1,313	1,459	31	3,877
14	844	218	1,416	1,468	31	3,977
15	854	241	1,313	1,639	31	4,078
16	870	271	1,312	1,694	31	4,177
17	853	273	1,315	1,810	31	4,282
18	891	323	1,313	1,865	31	4,423

Table I.2 shows new resources added to the portfolio for the winter at PRM levels ranging between 11 and 18 percent. Winter additions are led by summer additions where summer DSM selection may contribute to winter depending on the attributes of bundle selections; while winter additions follow a general trend, variations are observed at the 16 and 18 percent PRM levels in particular.

In aggregate, the summer and winter additions result in a smooth progression of reliability measures (e.g., loss of load hours, loss of load events, and incremental cost of reliability) reported in the next section of this appendix.

Table I.2 – Winter Expansion Resource Additions by PRM

PRM (%)	Capacity at Winter Peak (MW)					
	DSM		FOT	Nat. Gas	Geo-Thermal/ Other	Total
	Energy Efficiency	Demand Response				
11	729	0	306	1,458	31	2,524
12	727	0	314	1,484	31	2,556
13	736	0	321	1,682	31	2,769
14	749	0	328	1,692	31	2,801
15	759	0	336	1,889	31	3,015
16	775	0	0	1,915	31	2,721
17	759	0	350	2,087	31	3,227
18	796	0	0	2,113	31	2,940

Reliability Metrics

Table I.3 shows EUE, LOLH, and LOLE reliability results before and after adjusting these reliability metrics for PacifiCorp's participation in the NWPP reserve sharing agreement. Each of the reliability metrics generally improve as the PRM increases and after accounting for benefits associated with PacifiCorp's participation in the NWPP reserve sharing agreement. After accounting for its participation in the NWPP reserve sharing agreement, all PRM levels meet a one day in ten year planning criteria (LOLH at or below 2.4), and PRM levels of between 17 and 18 percent meet a one event in ten year planning criteria (LOLE at or below 0.1).

Table I.3 - Simulated Reliability Metrics by PRM

Year	PRM (%)	Before NWPP Adjustment			After NWPP Adjustment		
		Simulated Energy Not Served (GWh)	LOLH (<2.4 target year) (Hour)	Loss of Load Episodes	EUE (GWh)	LOLH (Hour)	Modeled Loss of Load Episodes
2019 IRP							
2030	11	602	2.46	1.12	327	1.34	0.54
	12	1,038	3.75	1.45	637	2.30	0.78
	13	514	1.97	0.90	279	1.07	0.45
	14	377	1.64	0.79	196	0.85	0.37
	15	193	0.98	0.44	106	0.54	0.23
	16	157	0.87	0.38	88	0.49	0.18
	17	71	0.54	0.27	35	0.27	0.09
	18	107	0.41	0.19	56	0.21	0.08

The reliability metrics do not monotonically improve with each incremental increase in the PRM. This is influenced by the physical location of new resources within PacifiCorp's system at varying PRM levels and the ability of these resources to serve load in all load pockets when Monte Carlo sampling is applied to load, hydro generation, and thermal unit outages.

The 12 percent reports higher EUE, but is able to meet the 12 percent PRM with an efficiency that keeps the incremental cost of EUE in line with the rest of the PRM levels (refer to Table I.5 under System Costs, below). Absent the NWPP adjustment, the PRM 13 percent is the cross over point where the LOLH is below the 2.4 hour per year limit.

Considering that the reliability metrics are measuring very small magnitudes of change among the different PRM levels, the PaR outputs are fit to a logarithmic function to report the overall trend in reliability improvements as the PRM level increases. Table I.4 shows the fitted EUE LOLH, and LOLE results. Figure I.2, Figure I.3 and Figure I.4 show a plot of the fitted trend for EUE, LOLH, and LOLE, respectively, after accounting for PacifiCorp's participation in the NWPP reserve sharing agreement.

Table I.4 - Fitted Reliability Metrics by PRM

	Before NWPP Adjustment			**After NWPP Adjustment**		
PRM (%)	EUE (GWh)	LOLH (<2.4 target year) (Hour)	Modeled Loss of Load Episodes	EUE (GWh)	LOLH (Hour)	Modeled Loss of Load Episodes
11	504	1.92	0.78	878	3.36	1.44
12	353	1.38	0.58	619	2.43	1.05
13	265	1.06	0.46	467	1.88	0.82
14	202	0.84	0.37	360	1.50	0.66
15	154	0.66	0.31	276	1.20	0.53
16	114	0.52	0.25	208	0.95	0.43
17	81	0.40	0.21	151	0.74	0.35
18	52	0.29	0.17	101	0.56	0.27

Figure I.2 - Expected and Fitted Relationship of EUE to PRM

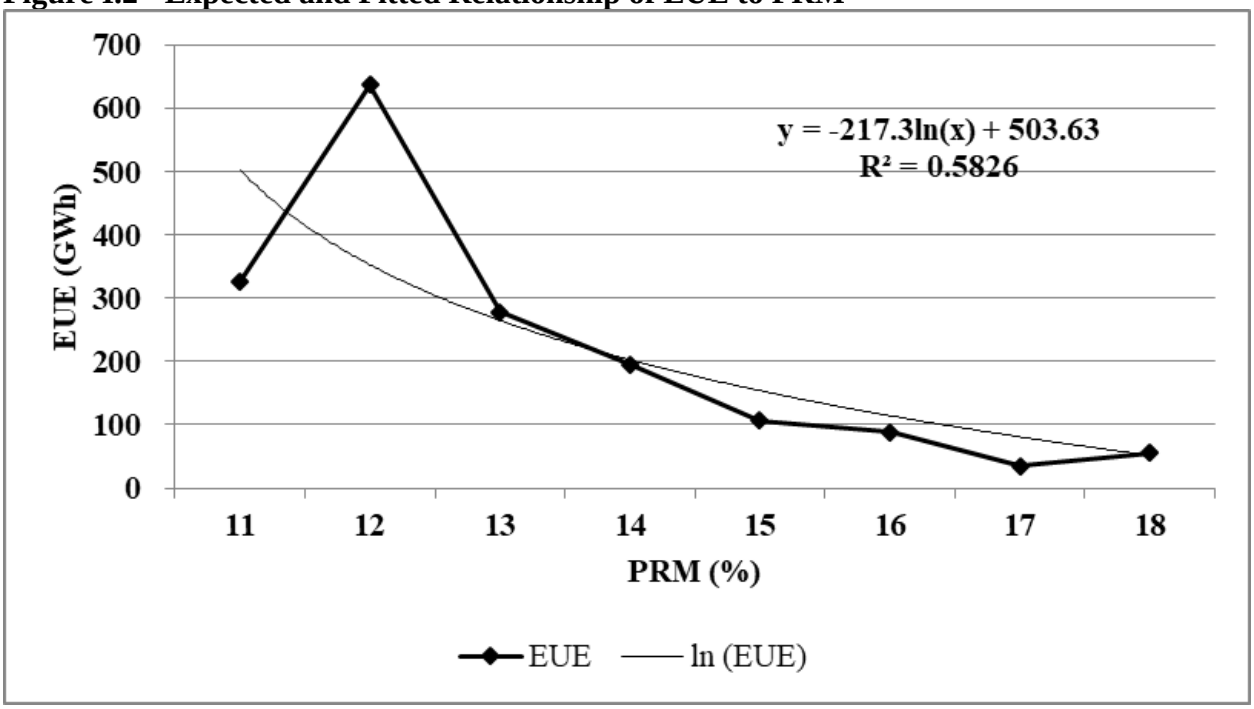


Figure I.3 - Expected and Fitted Relationship of LOLH to PRM

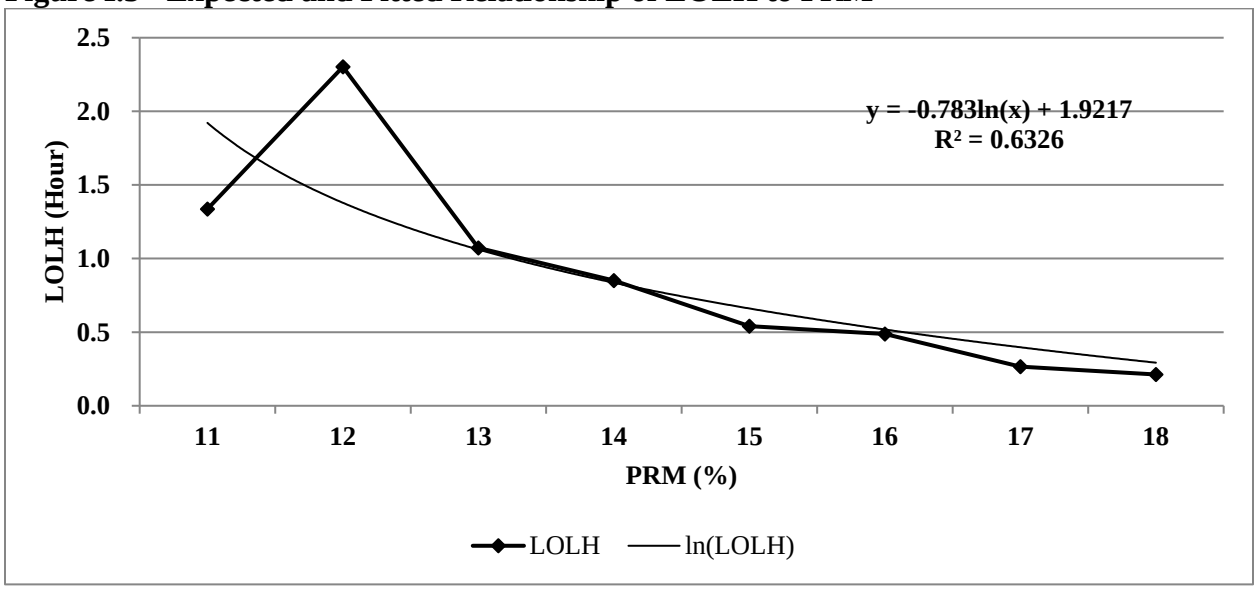
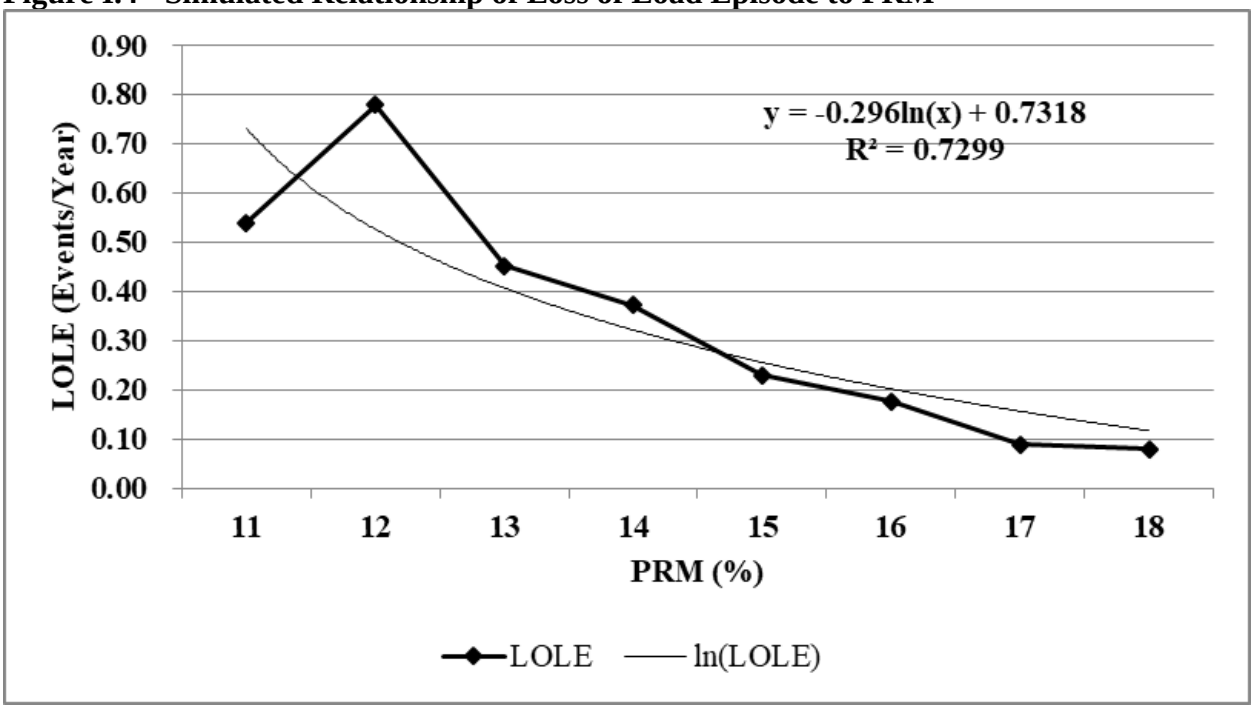


Figure I.4 - Simulated Relationship of Loss of Load Episode to PRM



System Costs

For the 2020 reference year, Table I.5 shows the stochastic mean of system variable production costs and the upfront capital and run-rate fixed costs, including the cost of new DSM resources, for each portfolio developed at PRM levels ranging between 11 and 18 percent. The fixed costs associated with these new resource additions drive total costs higher as PRM levels increase. DSM run-rate costs vary depending on resource additions for demand response and new resources where gas was added.

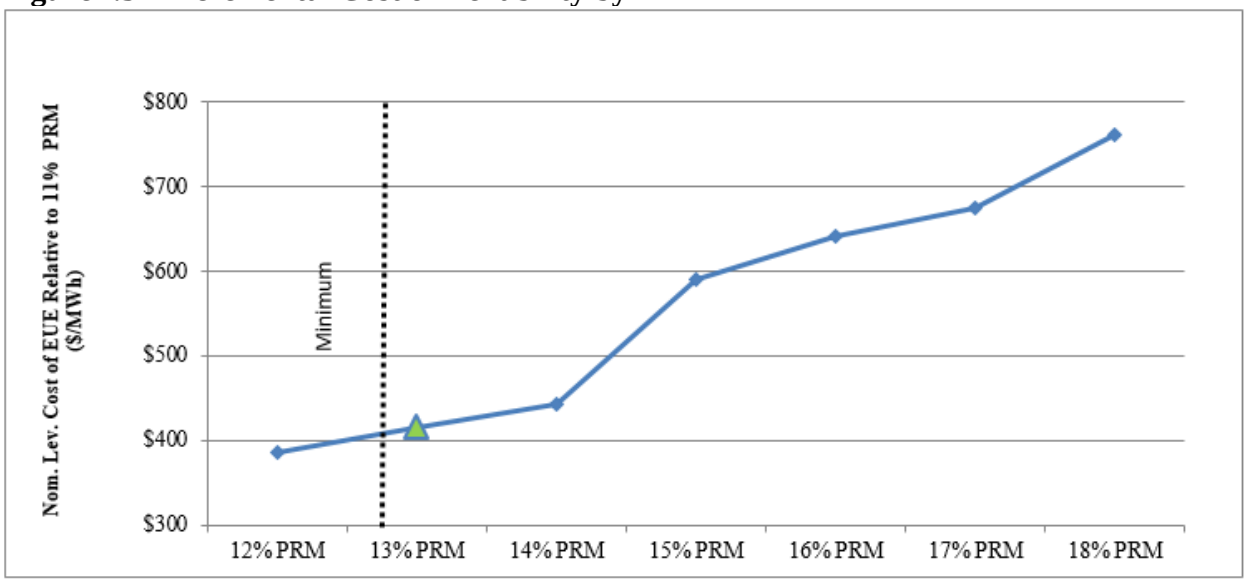
Table I.5 – System Variable, Up-front Capital, and Run-rate Fixed Costs by PRM

PRM (%)	System Production Costs ($m)	Energy Efficiency ($m)	Demand Response ($m)	Existing Resource Fixed Costs ($m)	New Resource Fixed Cost ($m)	Total ($m)
11	11,368	818	120	2,823	3,398	18,527
12	11,383	802	131	2,823	3,472	18,611
13	11,352	833	122	2,823	3,540	18,670
14	11,302	855	130	2,823	3,609	18,719
15	11,313	886	120	2,823	3,684	18,825
16	11,134	936	132	2,823	3,862	18,887
17	11,289	863	134	2,823	3,830	18,939
18	11,149	983	137	2,823	3,931	19,023

Incremental Cost of Reliability

Figure I.5 depicts the incremental cost of reliability, stated as the nominal levelized cost of EUE relative to 11 percent PRM, at PRM levels ranging between 12 and 18 percent. The incremental cost of reliability rises intuitively as PRM levels increase, and illustrates a significant step-change noted when the PRM hits 15 percent and onward.

Figure I.5 - Incremental Cost of Reliability by PRM



Conclusion

PacifiCorp will continue to use a 13 percent target PRM in its resource planning after evaluating the relationship between cost and reliability in the PRM study. A PRM below 13 percent would not sufficiently cover the need to carry short-term operating reserve needs (contingency and regulating margin) and longer-term uncertainties such as extended outages and changes in customer load.[2] A PRM above 15 percent improves reliability above a one event in ten year planning level, although with a 300 to 700 percent increase in the incremental cost per megawatt-hour of reduced EUE when compared to a 13 percent PRM. With these considerations, the selected 13 percent PRM level ensures PacifiCorp can reliably meet customer loads while maintaining operating reserves, with a planning criteria that meets one day in 10 year planning targets, at the lowest reasonable cost.

[2] PacifiCorp must hold approximately six percent of its resources in reserve to meet contingency reserve requirements and an estimated additional 4.5 percent to 5.5 percent of its resources in reserve, depending upon system conditions at the time of peak load, as regulating margin. This sums to 10.5 percent to 11.5 percent of operating reserves before even considering longer-term uncertainties such as extended outages (transmission or generation) and customer load growth.

APPENDIX J – WESTERN RESOURCE ADEQUACY EVALUATION

Introduction

The Public Service Commission of Utah, in its 2008 Integrated Resource Plan (IRP) Order, directed PacifiCorp to conduct two analyses pertaining to the company's ability to support reliance on market purchases:

> *Additionally, we direct the Company to include an analysis of the adequacy of the western power market to support the volumes of purchases on which the Company expects to rely. We concur with the Office [of Consumer Services], the WECC is a reasonable source for this evaluation. We direct the Company to identify whether customers or shareholders will be expected to bear the risks associated with its reliance on the wholesale market. Finally, we direct the Company to discuss methods to augment the Company's stochastic analysis of this issue in an IRP public input meeting for inclusion in the next IRP or IRP update.*[1]

In the past, PacifiCorp has fulfilled this requirement by evaluating the Western Electricity Coordinating Council (WECC) Power Supply Assessment (PSA) to glean trends and conclusions from the supporting analysis. While an updated PSA has not been published in time for this IRP, there is a published update available for the North American Electric Reliability Corporation (NERC) Long Term Reliability Assessment (LTRA). Past PSA reports were based on data publicly available in the NERC LTRA, and the latest available LTRA report[2] is used in lieu of the WECC PSA in this appendix. This evaluation, along with a discussion on risk allocation associated with reliance on market purchases, is provided below. As part of this evaluation, PacifCorp also reviewed the status of resource adequacy assessments prepared for the Pacific Northwest by the Pacific Northwest Resource Adequacy Forum.

NERC 2018 Long Term Reliability Assessment

The NERC LTRA, issued December 20, 2018, was developed based on data collected from seven regional entities, including WECC. NERC staff independently assesses collected data to develop the LTRA for the North American Bulk-Power System. The NERC LTRA assessment identifies trends and risks over a 10-year (2019-2028) study period. The 2018 LTRA concludes that the WECC, inclusive of four U.S. and two Canadian subregions, are expected to have sufficient generation capacity to exceed reserve requirements during the assessment period.

[1] Public Service Commission of Utah, PacifiCorp 2008 Integrated Resource Plan, Report and Order, Docket No. 09-2035-01, p. 30.
[2] North American Electric Reliability Corporation 2018 Long Term Reliability Assessment, www.nerc.com/pa/RAPA/ra/Pages/default.aspx

Resources

The NERC LTRA organizes resources into two broad categories its 10 year WECC region reliability assessment:

Anticipated Resources:

- 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 with firm contracts
- Less confirmed retirements

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
- Nonfirm net capacity transfers and transfers without firm contracts, but assessed to have a high probability of future implementation
- Less unconfirmed retirements

Planning Reserve Margin

The LTRA defines "planning reserve margin" as Resources less Demand, divided by Demand, shown as a percentile.

$$\left(\frac{\textbf{Resources - Demand}}{\textbf{Demand}} \right) \%$$

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: Anticipated Reserve Margin exceeds the Reference Margin Level
- Marginal: Anticipated Reserve Margin exceeds the Reference Margin Level but there are low expectations in meeting all forecast parameters; alternately, Anticipated Reserve Margin is below the Reference Margin Level but sufficient Tier 2 resources are projected to cover the shortall.
- Inadequate: Anticipated Reserve Margin is significantly less than Reference Margin Level and load interruption is likely.

WECC Subregions

Table J.1 presents the WECC subregions used for the NERC LTRA. In the data that follows, the two subregions in Canada are not considered.

Table J.1 – WECC Subregion Descriptions

Designation	Subregion	Country	Peaking Assumption
CAMX	California to Mexico	United States	Summer
NWPP	Northwest Power Pool	United States	Summer
RMRG	Rocky Mountain Reserve Group	United States	Summer
SRSG	Southwest Reserve Sharing Group	United States	Summer
AB	Alberta	Canada	Winter
BC	British Columbia	Canada	Winter

LTRA WECC Assessment

Table J.2 through J.4 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 J.2 – NERC LTRA Anticipated Reserve Margin

Anticipated Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NWPP	Summer	27.6%	25.9%	24.6%	22.8%	23.8%	23.6%	23.7%	23.7%	26.5%	22.0%
RMRG	Summer	33.7%	26.6%	24.9%	23.5%	21.1%	19.6%	18.0%	16.8%	15.5%	14.0%
SRSG	Summer	30.8%	29.4%	27.5%	24.0%	20.9%	18.8%	16.6%	15.0%	12.0%	10.5%
CAMX	Summer	23.3%	30.6%	24.3%	23.6%	24.5%	20.7%	20.4%	20.9%	20.7%	20.3%

Table J.3 – NERC LTRA Prospective Reserve Margin

Prospective Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NWPP	Summer	27.8%	26.1%	24.8%	22.9%	24.0%	23.8%	23.8%	23.9%	26.6%	22.2%
RMRG	Summer	33.7%	26.6%	24.9%	23.5%	21.5%	20.0%	18.4%	17.1%	15.8%	14.4%
SRSG	Summer	33.6%	32.4%	30.9%	27.5%	24.3%	22.1%	19.9%	18.2%	15.1%	13.6%
CA/MX	Summer	32.5%	43.3%	42.1%	42.9%	43.9%	40.2%	39.8%	40.4%	40.2%	39.7%

Table J.4 – NERC LTRA Reference Reserve Margin

Reference Planning Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NWPP	Summer	19.7%	19.7%	19.5%	19.6%	19.6%	19.5%	19.4%	19.4%	19.3%	19.1%
RMRG	Summer	16.8%	16.8%	16.5%	16.4%	16.1%	15.9%	15.7%	15.6%	15.4%	15.3%
SRSG	Summer	15.1%	15.1%	14.9%	14.6%	14.5%	14.3%	14.2%	14.0%	13.9%	13.8%
CAMX	Summer	12.4%	12.3%	12.1%	12.1%	12.0%	12.1%	12.0%	12.0%	12.0%	12.0%

Using this data, a reserve margin position can be calculated to show project shortfalls, both with and without the inclusion of prospective resource additions. Table J.5 reports the reserve margin differential based on Anticipated resources, whereas Table J.6 reportes the reserve margin differential assuming Prospetive 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 Referene Margin.

Based on this evaluation, potential shortfalls in Planning Reserve Margin are small and 8-9 years distant.

Table J.5 –Planning Reserve Margin Shortfalls by Subregion with Anticipated Resources

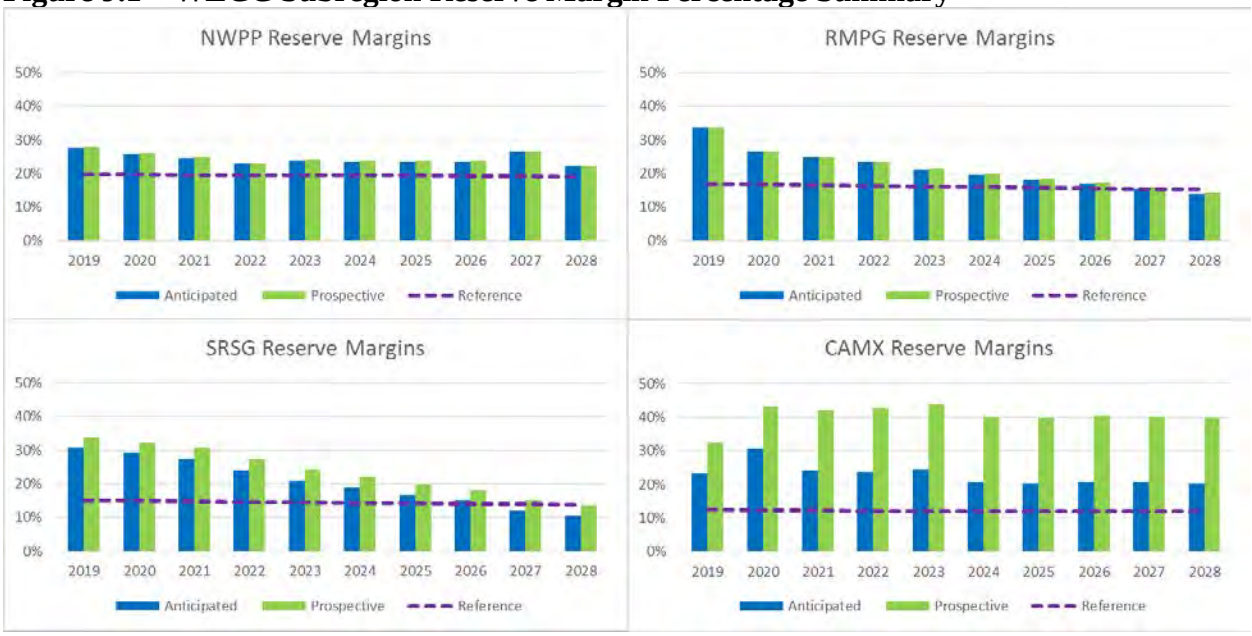
Shortfalls Assuming Anticipated Reserve Margin											
U.S. WECC Subregion	**Peaking Assumption**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
NWPP	Summer	7.9%	6.2%	5.1%	3.2%	4.3%	4.2%	4.3%	4.3%	7.2%	2.9%
RMRG	Summer	16.9%	9.8%	8.4%	7.1%	5.1%	3.7%	2.3%	1.2%	0.1%	**-1.2%**
SRSG	Summer	15.7%	14.3%	12.6%	9.4%	6.4%	4.5%	2.5%	1.0%	**-2.0%**	**-3.3%**
CA/MX	Summer	10.9%	18.3%	12.2%	11.6%	12.5%	8.6%	8.4%	8.9%	8.7%	8.2%

Table J.6 -- Planning Reserve Margin Shortfalls by Subregion with Prospective Resources

Shortfalls Assuming Prospective Reserve Margin											
U.S. WECC Subregion	**Peaking Assumption**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
NWPP	Summer	8.1%	6.4%	5.3%	3.3%	4.5%	4.3%	4.4%	4.5%	7.4%	3.1%
RMRG	Summer	16.9%	9.8%	8.4%	7.1%	5.4%	4.0%	2.6%	1.5%	0.4%	**-0.9%**
SRSG	Summer	18.5%	17.3%	16.0%	12.8%	9.8%	7.8%	5.7%	4.2%	1.2%	**-0.2%**
CA/MX	Summer	20.2%	31.0%	30.0%	30.8%	31.9%	28.1%	27.8%	28.4%	28.2%	27.7%

Figure J.1 graphically illustrates the relative margins for each subregion.

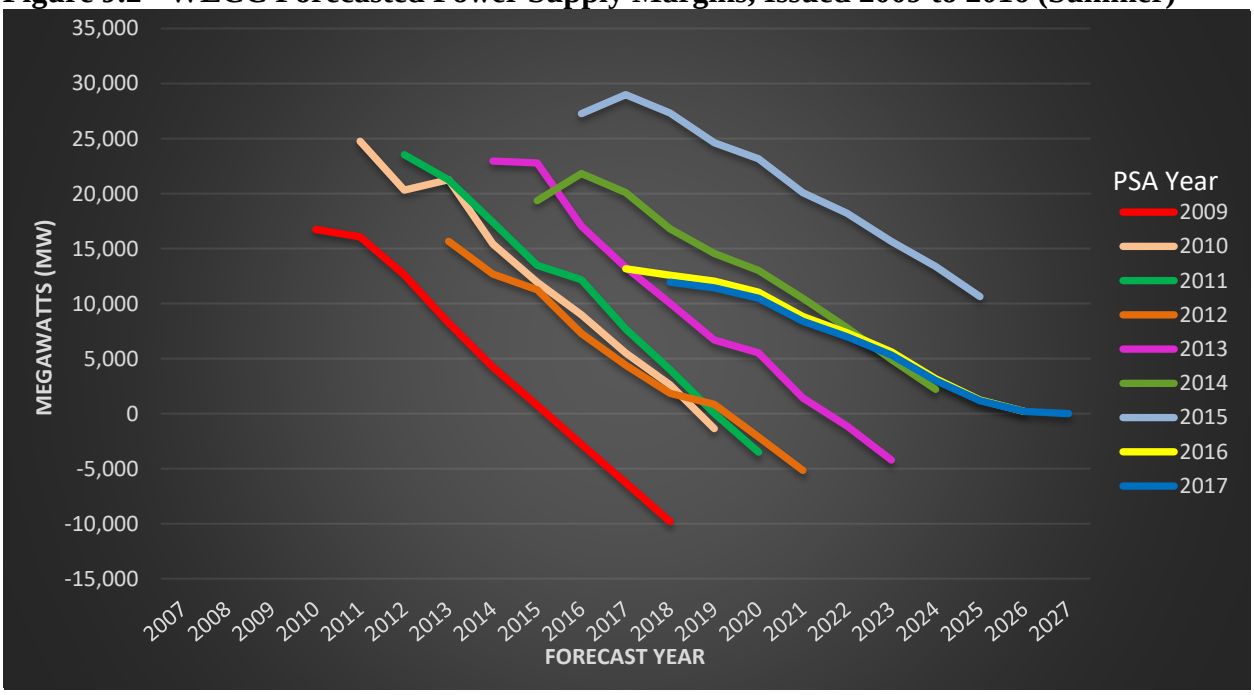
Figure J.1 – WECC Subregion Reserve Margin Percentage Summary



Prior Measures

PacifiCorp's past assessents, relying on caluclations incorporated into the WECC PSA, have reporting a rolling succession of power supply margins, where each year there is a downward trend in reserve margins extending into the future. Figure J.2 presents this trend based on past WECC PSA reports. The rolling nature of each year's outcome tells us that while declining reserve margins are important, in reality 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.

Figure J.2 - WECC Forecasted Power Supply Margins, Issued 2009 to 2016 (Summer)



Note: WECC Power Supply Assessments include Class 1 Planned Resources Only

Pacific Northwest Resource Adequacy Forum's Adequacy Assessment

As in the 2017 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. The Resource Adequacy Advisory Committee issued a Pacific Northwest Power Supply Adequacy Assessment for 2021 on August 10, 2016[3]. This assessment concluded that power supply is expected to be adequate through 2021 primarily focused on winter season. Consistent with the prior year filing, the updated forecasts indicate Pacific Northwest energy and capacity surplus will become a deficit around years 2021 and 2022, primarily focused on winter and spring season.

[3] Pacific Northwest Power Supply Adequacy Assessment for 2021, at: www.nwcouncil.org/media/7150504/2021-adequacy-assessment-final-aug_9_2016.pdf

Customer versus Shareholder Risk Allocation

Market purchase costs are reflected in rates. Consequently, customers bear the price risk of PacifiCorp's reliance on a given level of market purchases. However, customers also bear the cost impact of the company's decision to build or acquire resources if those resources exceed market alternatives and result in an increase in rates. These offsetting risks stress the need for robust IRP analysis, efficient RFPs and ability to capture opportunistic procurement opportunities when they arise.

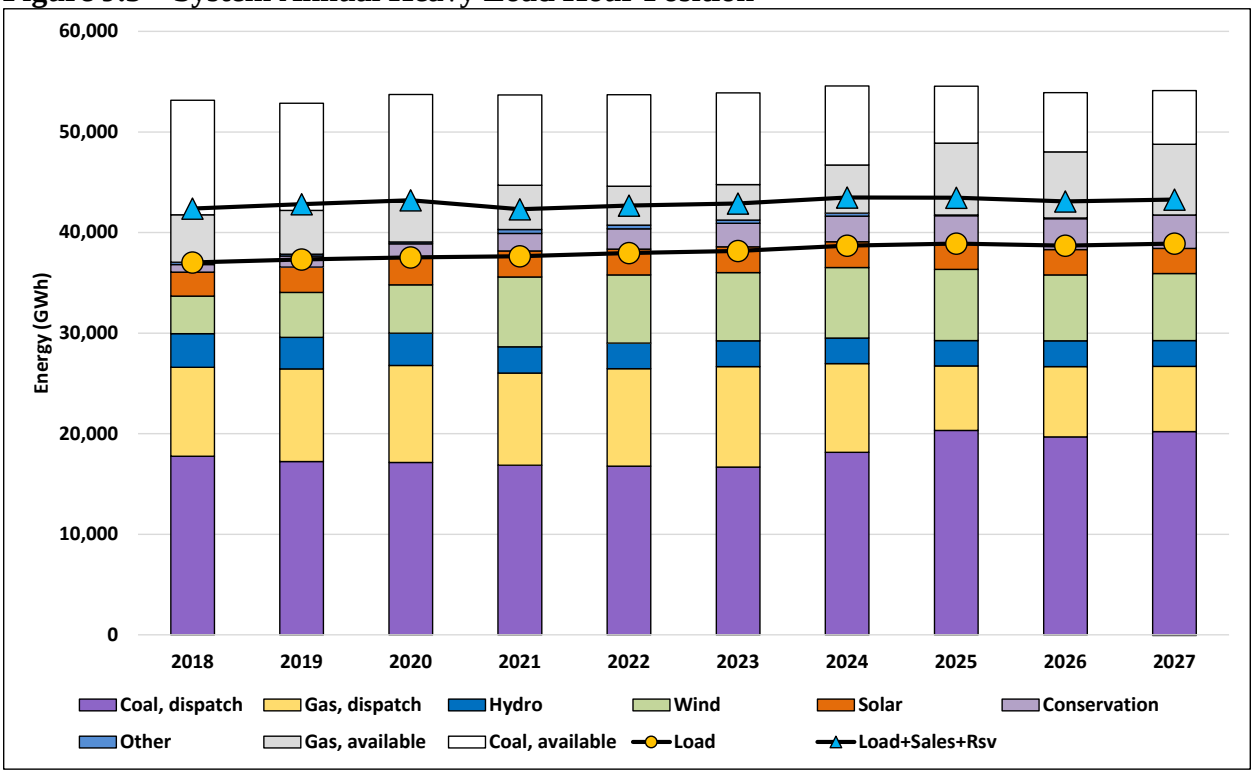
PacifiCorp's Energy Position

Figure J.3 to Figure J.5 illustrates PacifiCorp's energy position developed from the 2017 IRP Update, progress from annual to hourly views of system position:

- System Annual Heavy Load Hour (HLH) position
- July Monthly Heavy Load Hour position
- Sample July Peak Day Position

The energy position is compared to a load target, where load includes projected sales and reserve requirement. The gap between energy and load are met by market energy, however in many cases could have been met by other system resources.

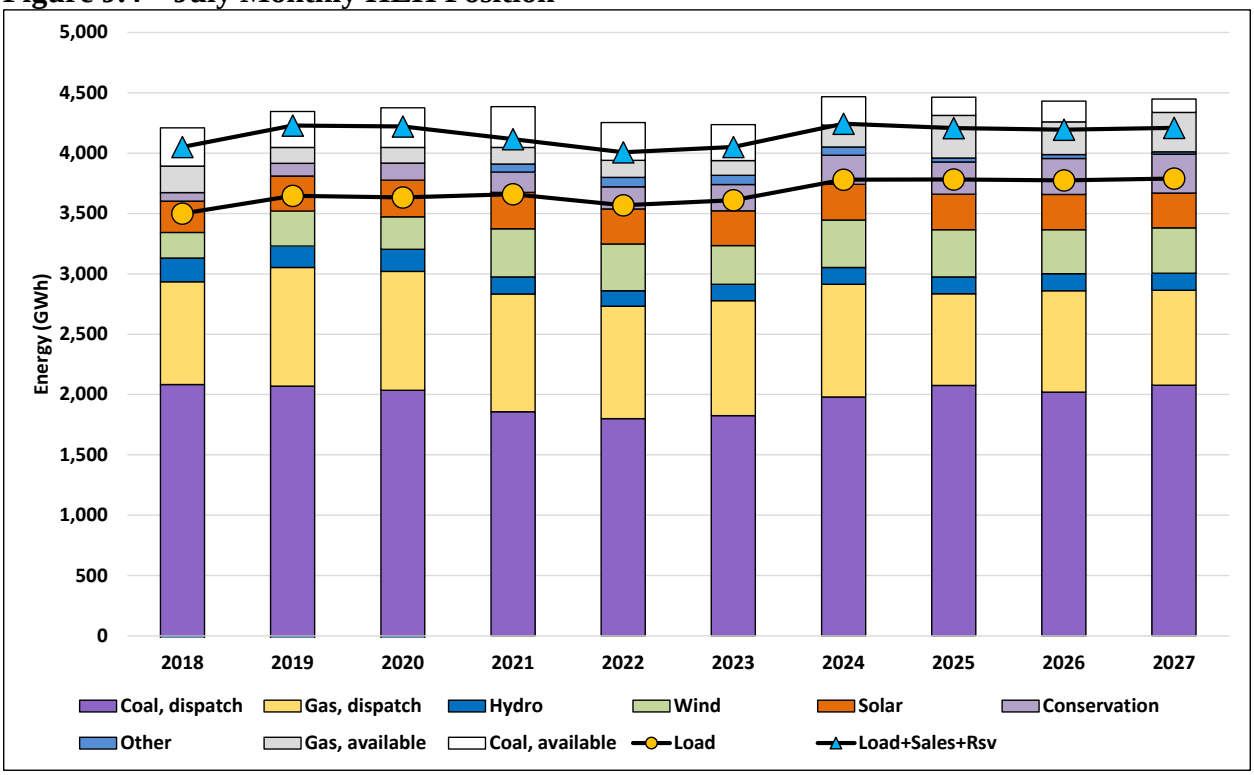
Figure J.3 – System Annual Heavy Load Hour Position



The annual position during heavy load hour with existing and planned resources, demonstrated system position without market purchases. The top blocks on each bar represents available

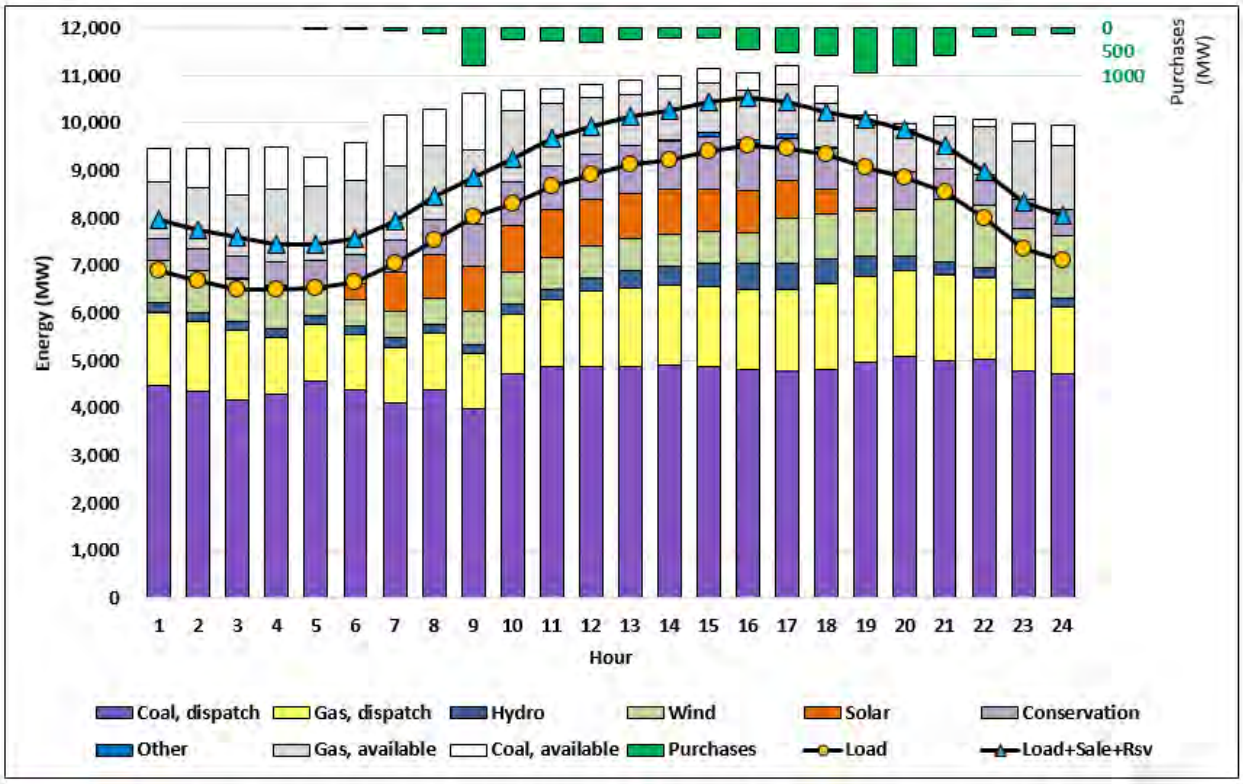
undispatched capacity. The gap between energy position and load-plus-sales-plus-reserves could be met by market purchases, increased dispatch, reduction in sales, or a combination actions.

Figure J.4 – July Monthly HLH Position



The peak heavy load hour is the month of July, the system runs tighter compared to the annual basis. There is less undispatched thermal capacity available to meet load-plus-sales-plus-reserves than in the system annual HLH view. However, undispatched capacity still exceeds requirements on a monthly level. The gap between energy position and load-plus-sales-plus-reserves could be met by market purchases, increased dispatch, reduction in sales, or a combination of the three. The model makes this decision on the basis of economics and prevailing transmission constraints in a given hour.

Figure J.5 – Sample July Peak Day Position



The peak heavy load hour day runs tighter again compared to both annual and month view. The hourly variations and purchase drivers are captured in the sample day that cannot be seen in either annual or month peak HLH in Figure J.4 and Figure J.5. On an energy basis, the gap between energy and load-plus-sales is highest in hour 19 and 20. This is generally consistent with the highest solar shoulder hour, or twilight peak, where solar is fading and other generation is ramping up to meet the gap.

Market Purchases

As described in Volume I, Chapter 6 (Resource Options), 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 made 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.

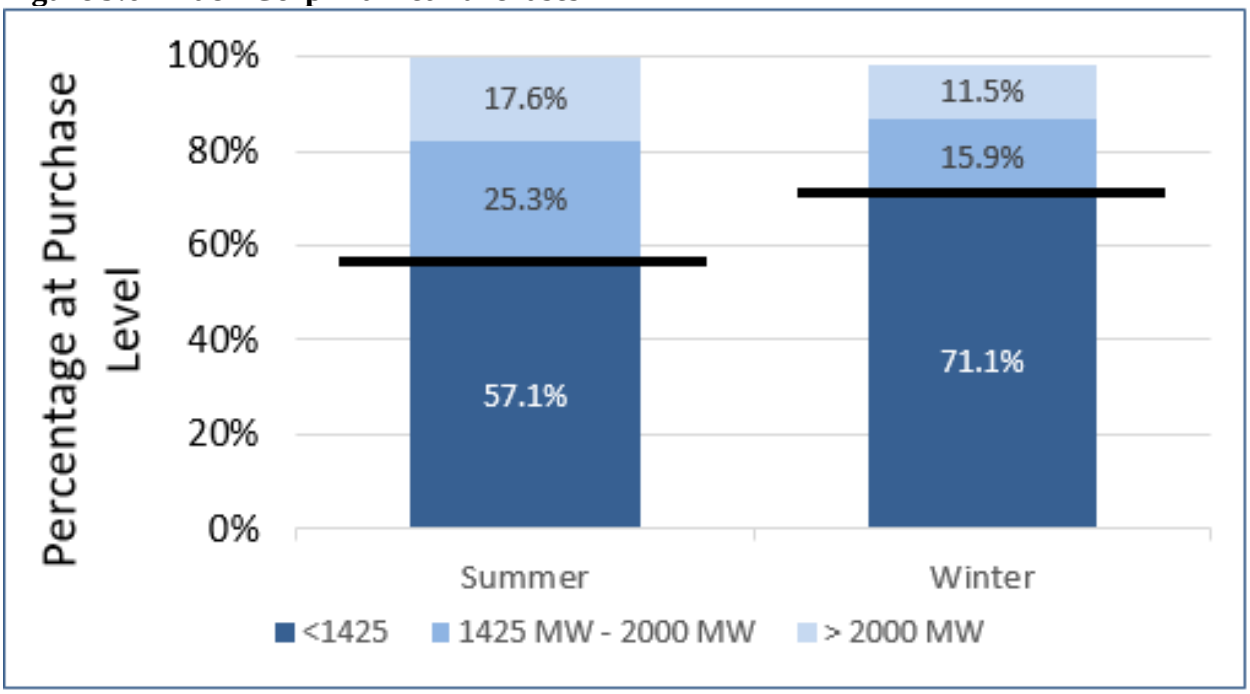
In developing FOT limits for the 2019 IRP, PacifiCorp reviewed the studies described in the sections above as part of its assessment of market reliance in addition to consideration of its active participation in wholesale power markets, its view of physical delivery constraints, and market liquidity and market depth.The 2019 IRP FOT limits is 1,425 MW, reduced from 1,575 MW in the 2017 IRP, due to a COB decrease of 150 MW, reflecting expired reservation and review of historical derates as shown in Table J.7.

Table J.7 – Maximum Available Front Office Transactions by Market Hub

Market Hub/Proxy FOT Product Type	Availability Limit (MW)			
	2019		2017	
	Summer (July)	Winter (December)	Summer (July)	Winter (December)
Mid-Columbia (Mid-C)				
Flat Annual or Heavy Load Hour	400	400	No Change	
Heavy Load Hour	375	375	No Change	
California Oregon Border (COB)				
Flat Annual or Heavy Load Hour	250	250	Reduced to 250 from 400	
Nevada Oregon Border (NOB)				
Heavy Load Hour	100	100	No Change	
Mona				
Heavy Load Hour	300	300	No Change	
Total	**1,425**	**1,425**	**1,575**	**1,575**

Figure J.6 shows PacifiCorp historical market purchases at three volume thresholds. The majority of actual purchases conform to IRP FOT planning limits. As PacifiCorp is a summer-peakingsystem higher volume purchases occurred more frequently in the summer than in the winter. This assessment showed that from 2009 to 2017, 27 percent of winter peak load hour purchases and 43 percent of summer peak load hour purchases were higher than the assumed IRP FOT planning limit of 1,425 MW.

Figure J.6 – PacifiCorp Market Purchases



Aligned with review of the regional studies discussed above, and the historical market purchases and transactions, PacifiCorp has selected a peak-season FOT limit of 1,425MW for the 2019 IRP. The company will continue to refine its assessments of market depth and liquidity for transactions, informed by actual operations, to quantify the risk associated with the level of market reliance. Several FOT studies are discussed and evaluated in Volume I, Chapter 7 (Modeling and Portfolio Evluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results).

APPENDIX K – CAPACITY EXPANSION RESULTS DETAIL

Portfolio Case Build Tables

This section provides the System Optimizer portfolio build tables for each of the case scenarios as described in the portfolio development section of Chapter 7. There are thirty Initial Development cases, ten C-cases, seven CP-cases, six front office transactions (FOT) risk assessment cases, six Gateway & No Gas cases, eight sensitivity cases, three re-bundled demand-side management (DSM) cases, and five P-70 cases.

Table K.1 – Initial Development Study Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-01	Coal Study Benchmark	-	24,407	Base	Base	Med Gas, Med CO_2	Base	Segment F	2033
P-02	Regional Haze References/ Regional Haze Base	-	23,191	Base	Base	Med Gas, Med CO_2	Base	Segment F	2031
P-03	Regional Haze Intertemporal/ Regional Haze Base Intertemporal	-	21,951	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-04	Coal Study C-42/ Coal Study Base	-	21,720	Base	Base	Med Gas, Med CO_2	Base	Segment F	2028
P-06	Transition Case C-44a/Alternative Base	-	21,980	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-07	Transition Case C-44b	P-06	21,905	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-08	Naughton 3 Small GC (P-03 basis)	P-03	21,979	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-09	Naughton 3 Large GC (P-03 basis)	P-03	21,885	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-10	Economic Retirement 1*	P-04	21,723	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-11	Cholla 4 Retirement 2020	P-09	21,873	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-12	Economic Retirement 2*	P-06	21,854	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-13	Bridger 1&2 SCR	P-11	22,346	Base	Base	Med Gas, Med CO_2	Base	Segment F	2032
P-14	Naughton and Jim Bridger Retirement 2022 (P11 Basis)	P-09	21,696	Base	Base	Med Gas, Med CO_2	Base	Segment F	2028
P-15	Retire All Coal by 2030	P28	22,132	Base	Base	Med Gas, Med CO_2	Base	Segment F	2027
P-16	No CO_2	P04	18,634	Base	Base	Med Gas, No CO_2	Base	None	2028
P-17	High CO_2	P-15	22,070	Base	Base	Med Gas, High CO_2	Base	Segment F	2028
P-18	Social Cost of Carbon	P-15	30,022	Base	Base	Low Gas, SCC CO_2	Base	Segment F	2028
P-19	Low Gas	P-04	20,882	Base	Base	Low Gas, Med CO_2	Base	Segment F	2023
P-20	High Gas	P-07	22,746	Base	Base	High Gas, Med CO_2	Base	Segment F	2029
P-28	Early Coalstrip Retirement	P-11	21,805	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-30	Naughton 1 & 2 Retirement 2022 (P11 Basis)	P-11	21,708	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-31	Naughton 1 & 2 Retirement 2025 (P11 Basis)	P-11	21,652	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-32	Naughton 1 & 2 Retirement 2025 (P07 Basis-No Gadsby 2020)	P-07	21,763	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

P-33	Oregon Study (P11 – JB1 & 2 Retire 2022)	P-11	21,895	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-34	Oregon Study (P11 – JB1 & 2 Retire 2022, Gadsby Retire)	P-11	21,949	Base	Base	Med Gas, Med CO_2	Base	Segment F	2028
P-35	Jim Bridger 3 & 4 Retiring 2022 (P11 with JB3 and 4 retiring 2022)	P-11	21,732	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-45	P31 with JB 1 & 2 Retirement	P-31	21,593	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46	P31 with JB 2 & 4 Retirement	P-31	21,419	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53	P-31 with JB1-2 Retiring 2025, JB3 Retiring 2028, and JB4 Retiring 2032	P-31	21,438	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-54	P-31 with JB2 Retiring 2024	P-31	21,708	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Table K.2 – C-Case Study Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-31C	P-11 with Naughton 1-2 Accelerated to 2025	P-31	21,639	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-36C	Economic Retirement 2* with Gateway Segment F (P12 with Gateway Segment F)	P-36	21,553	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-45C	P31 with JB 1 & 2 Retirement	P-45	21,431	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46C	P31 with JB 2 & 4 Retirement	P-46	21,422	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46J23C	Jim Bridger 3 & 4 Retirement 2023	P-46	21,385	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-47C	P45 GWS 2025-2028	P-47	21,467	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-48C	P45 and GWS 2023	P-48	21,482	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53C	P-31 with JB1-2 Retiring 2025, JB3 Retiring 2028, and JB4 Retiring 2032	P-53	21,450	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53J23C	Jim Bridger 1 & 2 Retirement 2023	P-53	21,394	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-54C	P-31 with JB2 Retiring 2024	P-54	21,591	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Table K.3 – CP-Case Study Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-36CP	Economic Retirement 2* with Gateway Segment F (P12 with Gateway Segment F)	P-36	21,553	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-45CP	P31 with JB 1 & 2 Retirement	P-45	21,480	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46CP	P31 with JB 2 & 4 Retirement	P-46	21,460	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46J23CP	P46C with JB3-4 Retiring 2023	P-46	21,402	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-47CP	P45 GWS 2025-2028	P-47	21,469	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-48CP	P45 and GWS 2023	P-48	21,457	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53CP	P-31 with JB1-2 Retiring 2025, JB3 Retiring 2028, and JB4 Retiring 2032	P-53	21,479	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Table K.4 – Preferred Portfolio Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-45CNW	P45CP No DJ Wind	P-45	21,624	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Table K.5 – FOT Risk Assessment Case Study Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-45CP-FOT	P31 with JB 1 & 2 Retirement	P-45CP	21,977	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46CP-FOT	P31 with JB 2 & 4 Retirement	P-46CP	21,960	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-47CP-FOT	P45 GWS 2025-2028	P-47CP	21,942	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-48CP-FOT	P45 and GWS 2023	P-48CP	21,936	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53CP-FOT	P-31 with JB1-2 Retiring 2025, JB3 Retiring 2028, and JB4 Retiring 2032	P-53CP	21,979	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-45CNW-FOT	P45CP No DJ Wind	P-45CP	22,154	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Table K.6 – Gateway & No Gas Case Study Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-29	P-45CNW, No New Gas Option	P-45CNW	21,798	Base	Base	Med Gas, Med CO2	Base	Segment F	-
P-29 PS	P-29 with Pumped Storage	P-29	21,970	Base	Base	Med Gas, Med CO2	Base	Segment F	-

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-22	P-45CNW, Energy Gateway Segment D.3	P-45CNW	21,886	Base	Base	Med Gas, Med CO2	Base	Add D.3	2030
P-23	P-45CNW, Energy Gateway Segment D.1 and F	P-45CNW	22,151	Base	Base	Med Gas, Med CO2	Base	Add Seg. F and D.1	2026
P-25	P-45CNW, Energy Gateway Segment D.3, E and H	P-45CNW	22,273	Base	Base	Med Gas, Med CO2	Base	Add Sub-seg. D.3 & Seg. E & H	2028
P-26	P-45CNW, Energy Gateway Segment H	P-45CNW	21,579	Base	Base	Med Gas, Med CO2	Base	Add Seg. H	2028

Table K.7 – Sensitivity Case Study Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
S-01	Low Load	P45CNW	20,617	Low	Base	Base	Base	Base	2030
S-02	High Load	P45CNW	22,602	High	Base	Base	Base	Base	2026
S-03	1 in 20 Load Growth	P45CNW	21,634	1 in 20	Base	Base	Base	Base	2026
S-04	Low Private Generation	P45CNW	21,758	Base	Low	Base	Base	Base	2029
S-05	High Private Generation	P45CNW	21,371	Base	High	Base	Base	Base	2030
S-06	Business Plan	P45CNW	21,695	Base	Base	Base	Base	Base	2028
S-07	No Customer Preference	P45CNW	21,609	Base	Base	Base	Base	Base	2030
S-08	All Customer Preference	P45CNW	21,636	Base	Base	Base	Base	Base	2030

Table K.8 – DSM Bundled Case Study Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-45DP	P31 with JB 1 & 2 Retirement	P-45	21,536	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46DP	P31 with JB 2 & 4 Retirement	P-46	21,458	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53DP	P-31 with JB1-2 Retiring 2025, JB3 Retiring 2028, and JB4 Retiring 2032	P-53	21,478	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Table K.9 – P70 Case Study Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-70	P-01 with JB 1 2022 RET	P-01	22,326	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-71	P-01 with NTN 1 2022 RET	P-01	22,482	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-72	P-01 with Hayden 1 2022 RET	P-01	22,432	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-73	P-01 with Hunter 1 RET	P-01	22,455	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-74	P-01 with Craig 1 2022 RET	P-01	22,447	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Table K.10 – East Side Resource Name and Description

Resource List	Detailed Description
CCCT - DJohns - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Dave Johnston Brownfield
CCCT - Utah-S - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Utah South
CCCT - Utah-S - G 1x1	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing - Utah South
IC Aero UN	Inter-cooled Simple Cycle Combustion Turbine Aero - Utah North
SCCT Aero UN	Simple Cycle Combustion Turbine Aero - Utah North
SCCT Frame DJ	Simple Cycle Combustion Turbine Frame - Dave Johnston Brownfield
SCCT Frame UTN	Simple Cycle Combustion Turbine Frame - Utah North
SCCT Frame UTS	Simple Cycle Combustion Turbine Frame - Utah North
Battery Storage - Utah S	Battery Storage - Utah South
Battery Storage - WYSW	Battery Storage - Wyoming Southwest
Battery Storage - Idaho	Battery Storage - Idaho
CAES - East	Compressed Air Energy Storage
Wind, Djohnston	Wind, Wyoming After DJ Retirement
Wind, GO	Wind, Goshen Idaho
Wind, UT	Wind, Utah
Wind, WYAE	Wind, Wyoming Aeolus
Wind+Storage, GO	Wind + Battery, Goshen Idaho
Wind+Storage, UT	Wind + Battery, Utah
Wind+Storage, WYAE	Wind + Battery, Wyoming Aeolus
Utility Solar - PV - Utah-S	Utility Solar - Photovoltaic - Utah South
Utility Solar - PV - WYSW	Utility Solar - Photovoltaic - Wyoming Southwest
Utility Solar - PV - Utah-N	Utility Solar - Photovoltaic - Utah North
Utility Solar+Storage - PV - Utah-S	Utility Solar + Battery - Photovoltaic - Utah South
Utility Solar+Storage - PV - GO	Utility Solar + Battery - Photovoltaic - Goshen Idaho
Utility Solar+Storage - PV - Huntington	Utility Solar + Battery - Photovoltaic - Huntington Brownfield
Utility Solar+Storage - PV - Utah-N	Utility Solar + Battery - Photovoltaic - Utah North
Demand Response, ID-3rd Party Contracts	Curtailment - Idaho
Demand Response, ID-Smart APPl	Direct Load Control Smart Appliances - Idaho
Demand Response, ID-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Idaho
Demand Response, ID-Thermostat	Direct Load Control-Smart Thermostat-Residential - Idaho
Demand Response, ID-Space HT	Direct Load Control-Space Heating-Residential, Commercial & Industrial - Idaho

Demand Response, ID-Irrigate	Direct Load Control-Irrigation -Idaho
Demand Response, UT-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Utah
Demand Response, UT-3rd Party Contracts	Curtailment - Utah
Demand Response, UT-Elec Vehicle	Direct Load Control-Electric Vehicle Charging -Utah
Demand Response, UT-Smart APPl	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Utah
Demand Response, UT-Space HT	Direct Load Control-Space Heating-Residential, Commercial & Industrial - Utah
Demand Response, UT-Thermostat	Direct Load Control-Smart Thermostat-Residential - Utah
Demand Response, UT-ICE storage	Ice Energy Storage - Utah
Demand Response, UT-Irrigate	Direct Load Control-Irrigation -Utah
Demand Response, WY-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Wyoming
Demand Response, WY-Irrigate	Direct Load Control-Irrigation -Wyoming
Demand Response, WY-3rd Party Contracts	Curtailment - Wyoming
Demand Response, WY-Ancillary Services	Ancillary Services - Wyoming
Demand Response, WY-ICE storage	Ice Energy Storage - Wyoming
Demand Response, WY-Room AC	Direct Load Control-Air Conditioning - Wyoming
Demand Response, WY-Smart APPl	Direct Load Control Smart Appliances - Wyoming
Demand Response, WY-Thermostat	Direct Load Control-Smart Thermostat-Residential - Wyoming
Demand Response, WY-Space HT	Direct Load Control-Space Heating-Residential, Commercial & Industrial - Wyoming
Energy Efficiency, ID	Energy Efficiency - Idaho
Energy Efficiency, UT	Energy Efficiency - Utah
Energy Efficiency, WY	Energy Efficiency - Wyoming
FOT Mona - SMR	Front Office Transaction - Summer HLH Product - Mona

Table K.11 – West-Side Resource Name and Description

Resource List	Detailed Description
CCCT - SOregonCal - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Southern Oregon
CCCT - WillamValcc - G 1x1	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing - Willamette Valley, Oregon
CCCT - WillamValcc - J 1x1	Combine Cycle Combustion Turbine J-Machine 1x1 with Duct Firing - Willamette Valley, Oregon
CCCT - Yakima - G 1x1	Combine Cycle Combustion Turbine G-Machine 1x1 with Duct Firing - Yakima, Washington
IC Aero PO	Inter-cooled Simple Cycle Combustion Turbine Aero - Portland-North Coast, Oregon
IC Aero SO	Inter-cooled Simple Cycle Combustion Turbine Aero - Southern Oregon
IC Aero WV	Inter-cooled Simple Cycle Combustion Turbine Aero - Willamette Valley, Oregon
IC Aero WW	Inter-cooled Simple Cycle Combustion Turbine Aero - Walla Walla, Washington
SCCT Frame SO	Simple Cycle Combustion Turbine Frame - Southern Oregon
Battery Storage - S Oregon	Battery Storage – West
Battery Storage - Wilamette Valley	Battery Storage – West
Battery Storage - Portland NC	Battery Storage – West
Battery Storage - Walla Walla	Battery Storage – West
Battery Storage - Yakima	Battery Storage – West
Wind, SO	Wind, Southern Oregon
Wind, YK	Wind, Yakima, Washington
Wind+Storage, SO	Wind + Battery, Southern Oregon
Wind+Storage, YK	Wind + Battery, Yakima, Washington
Utility Solar - PV - S-Oregon	Utility Solar - Photovoltaic - Southern Oregon
Utility Solar - PV - Yakima	Utility Solar - Photovoltaic - Yakima, Washington
Utility Solar+Storage - PV - Jbridger	Utility Solar + Battery - Photovoltaic - Bridger Plant
Utility Solar+Storage - PV - S-Oregon	Utility Solar + Battery- Photovoltaic - Southern Oregon
Utility Solar+Storage - PV - Yakima	Utility Solar + Battery- Photovoltaic - Yakima, Washington
Geothermal, Greenfield - West	Geothermal, Greenfield - West
Demand Response, CA-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - California
Demand Response, CA-3rd Party Contracts	Curtailment - California
Demand Response, CA-Irrigate	Direct Load Control-Irrigation - California
Demand Response, CA-ICE storage	Ice Energy Storage - California
Demand Response, CA-Thermostat	Direct Load Control-Smart Thermostat-Residential - California
Demand Response, CA-Space HT	Direct Load Control-Space Heating-Residential, Commercial & Industrial - California
Demand Response, OR-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Oregon

Demand Response, OR-3rd Party Contracts	Curtailment - Oregon
Demand Response, OR-Irrigate	Direct Load Control-Irrigation -Oregon
Demand Response, OR-Thermostat	Direct Load Control-Smart Thermostat-Residential - Oregon
Demand Response, OR-Ancillary Services	Ancillary Services - Oregon
Demand Response, OR-Elec Vehicle	Direct Load Control-Electric Vehicle Charging - Oregon
Demand Response, OR-ICE storage	Ice Energy Storage - Oregon
Demand Response, OR-Thermostat	Direct Load Control-Smart Thermostat-Residential - Oregon
Demand Response, OR-Room AC	Direct Load Control-Air Conditioning - Oregon
Demand Response, OR-Smart APPl	Direct Load Control Smart Appliances - Oregon
Demand Response, WA-Cool/WH	Direct Load Control-Cooling & Water Heating-Residential, Commercial & Industrial - Washington
Demand Response, WA-3rd Party Contracts	Curtailment - Washington
Demand Response, WA-Irrigate	Direct Load Control-Irrigation -Washington
Demand Response, WA-Thermostat	Direct Load Control-Smart Thermostat-Residential - Washington
Demand Response, WA-Ancillary Services	Ancillary Services - Washington
Demand Response, WA-ICE storage	Ice Energy Storage - Washington
Demand Response, WA-Room AC	Direct Load Control-Air Conditioning - Washington
Demand Response, WA-Smart APPl	Direct Load Control Smart Appliances - Washington
Energy Efficiency, CA	Energy Efficiency - California
Energy Efficiency, OR	Energy Efficiency - Oregon
Energy Efficiency, WA	Energy Efficiency - Washington
FOT COB - SMR	Front Office Transaction - Summer HLH Product - California Oregon Border
FOT COB - WTR	Front Office Transaction - Winter HLH Product - California Oregon Border
FOT MidColumbia - SMR	Front Office Transaction - Summer HLH Product - Mid Columbia
FOT MidColumbia - SMR - 2	Front Office Transaction - Summer HLH Product - Mid Columbia
FOT MidColumbia - WTR	Front Office Transaction - Winter HLH Product - Mid Columbia
FOT MidColumbia - WTR2	Front Office Transaction - Winter HLH Product - Mid Columbia
FOT NOB - SMR	Front Office Transaction - Summer HLH Product - Nevada Oregon Border
FOT NOB - WTR	Front Office Transaction - Winter HLH Product - Nevada Oregon Border

Table K.12 - Initial Cases, Detailed Capacity Expansion Portfolios

		Capacity (MW)																				Resource Totals 1/	
	P-01	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	185	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	555	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, OO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,100	-	-	-	-	-	-	-	-	1,920	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	67	28	-	-	-	-	-	-	328	-	-	-	-	400	-	-	300	1,028
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	172	-	-	-	-	-	-	-	-	172
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	48	37	3	726	-	-	-	-	-	-	-	-	85	813
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	87	-	-	-	-	-	-	-	-	-	-	-	-	-	-	87	87
	Total Solar	-	-	146	59	67	215	-	-	48	37	3	726	500	-	-	-	-	400	-	909	572	3,109
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	124.9	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	-	6.7	-	-	6.8	130.0	-	15.3	-	157.1	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	70	118
	Energy Efficiency, UT	58	67	67	69	75	68	67	68	65	62	54	53	50	50	49	36	34	26	24	26	667	1,069
	Energy Efficiency, WY	10	12	13	14	17	16	17	18	18	18	15	14	13	12	11	9	8	7	5	5	152	252
	Energy Efficiency Total	74	85	86	90	100	92	91	93	90	87	76	74	69	67	65	49	46	37	32	34	888	1,439
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	525.0	-	-	-	-	-	-	-	-	-	495	525	1,020
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	90.0	-	-	-	-	-	-	-	-	-	300.0	90.0	390.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	255.0	165.0	-	420.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	-	-	277	300	289	248	250	88	300	300	300	-	118
	FOT East - Winter	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	15
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	-	(351)
	JimBridger 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,408	-	1,408
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Solar	-	-	-	-	-	905	-	-	-	-	-	-	-	575	-	-	-	-	430	1,408	905	3,318
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, OR-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	61.4	-	-	61.4
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	7.5	-	-	-	189.4	2.0	-	200.7
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	39	42	46	34	36	35	39	37	33	31	30	29	26	26	26	26	25	24	383	657
	Energy Efficiency, WA	11	10	11	11	12	11	11	11	11	10	9	9	8	8	8	6	6	5	4	4	110	177
	Energy Efficiency Total	52	49	51	55	60	46	49	48	51	49	44	41	40	38	35	33	33	32	30	29	510	865
	Battery Storage - S-Oregon	-	-	-	-	15	-	-	-	-	135	-	-	-	-	-	-	-	-	-	75	150	225
	Battery Storage - Willamette Valley	-	-	-	-	75	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	90	90
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	60	60
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	45	120	165
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	959	621	684	716	218	279	255	313	1,069	1,014	1,075	1,075	1,075	1,075	1,075	1,014	1,038	1,048	1,075	611	834
	FOT West - Winter	151	131	269	304	314	247	254	257	307	321	311	341	307	374	314	234	212	211	-	-	256	243
	Existing Plant Retirements/Conversions	-	(308)	(573)	(224)	(1)	(62)	-	(148)	(3)	(764)	(93)	(506)	(350)	(114)	(557)	(156)	(117)	(280)	(2,260)	(1,451)		
	Annual Additions, Long Term Resources	130	134	299	203	431	3,178	149	148	190	1,117	750	1,941	609	689	608	82	95	469	2,091	3,483		
	Annual Additions, Short Term Resources	1,149	1,090	890	987	1,031	465	532	513	620	1,391	1,324	1,693	1,682	1,738	1,636	1,559	1,614	1,549	1,348	1,375		
	Total Annual Additions	1,279	1,224	1,189	1,191	1,462	3,643	681	661	810	2,508	2,074	3,634	2,290	2,427	2,244	1,641	1,709	2,018	3,439	4,858		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-02	Capacity (MW)																					Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																							
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																							
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	-	185	-	370	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	185	-	370	-	-	-	370	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	294	326	-	-	-	-	-	-	-	-	-	294	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,091	-	-	-	-	-	-	-	-	-	1,091
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	294	326	1,091	-	-	-	-	-	-	-	-	2,214	3,631
	Utility Solar - PV - Utah-S	-	-	146	59	67	16	-	-	-	-	-	-	-	-	-	-	-	400	-	-	288	688
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	12	-	-	-	-	-	-	-	-	-	-	500	-	-	-	12	512
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	-	9
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	3	713	-	-	-	-	-	-	-	-	-	716
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	184	-	-	-	-	-	-	-	-	-	-	-	-	-	-	184	184
	Total Solar	-	-	146	59	67	312	-	-	-	-	3	722	-	-	-	-	500	400	-	909	584	3,118
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	124.9	-	-	-	-	-	-	8.3	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	-	6.7	124.9	-	6.8	5.2	-	7.0	-	165.4	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	68	67	68	65	65	54	53	52	50	49	36	32	26	25	26	662	1,065
	Energy Efficiency, WY	10	10	11	14	15	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	149	249
	Energy Efficiency Total	74	83	85	88	91	92	92	94	91	90	76	74	71	68	65	49	45	37	33	35	879	1,431
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	285.0	-	-	-	-	-	-	-	-	-	495	285	780
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	105.0	-	-	-	-	-	-	-	-	-	285.0	105.0	390.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105.0	225.0	-	330.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	64	56	300	265	236	282	284	300	300	300	300	6	134
West	**Existing Plant Retirements and PPA Termination**																							
	JimBridger 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	-	(351)
	JimBridger 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																							
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	182	-	-	-	-	-	-	-	500	682
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,056	-	1,056
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	293	-	-	-	-	-	-	-	293
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Solar	-	-	-	-	-	905	-	-	-	-	-	-	182	393	-	-	-	-	430	1,056	905	2,966
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	-	-	-	9.2	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	9.4	-	10.0	4.1	-	-	-	114.0	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	42	39	39	43	41	39	37	33	31	30	29	26	27	26	26	25	24	392	667
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	110	178
	Energy Efficiency Total	52	49	48	55	53	53	56	54	52	49	44	41	40	38	35	34	33	32	30	29	520	878
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	345	-	-	-	-	-	-	-	-	-	-	345	345
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	135	135
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	135	135
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	959	585	653	692	208	203	214	288	1,075	1,075	1,075	1,075	1,075	1,075	1,075	943	878	1,052	1,075	587	814
	FOT West - Winter	151	131	268	303	314	246	252	254	303	435	426	385	453	374	324	248	265	251	-	-	266	269
	Existing Plant Retirements/Conversions	-	(308)	(186)	(224)	(1)	(62)	-	(535)	(85)	(912)	(93)	(506)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(1,451)		
	Annual Additions, Long Term Resources	130	132	294	201	221	3,282	156	155	142	1,648	456	2,062	478	516	479	83	585	469	1,690	3,055		
	Annual Additions, Short Term Resources	1,149	1,090	853	957	1,006	453	455	468	591	1,574	1,556	1,760	1,793	1,685	1,681	1,607	1,508	1,429	1,352	1,375		
	Total Annual Additions	1,279	1,222	1,148	1,158	1,227	3,735	612	623	733	3,222	2,012	3,822	2,272	2,201	2,161	1,691	2,093	1,898	3,042	4,430		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-03	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	185	185	-	185	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	185	185	-	555	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,061	-	-	-	-	-	-	-	-	-	1,061
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,061	-	-	-	-	-	-	-	-	1,920	3,601
	Utility Solar - PV - Utah-S	-	-	146	59	67	20	-	-	-	-	-	-	-	-	-	-	-	400	-	-	292	692
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	8	-	-	-	-	-	500	-	-	-	-	-	-	-	-	8	508
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	39
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	897	12	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	37	-	720	-	-	-	-	-	-	-	-	37	756
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	144	-	-	-	-	-	-	-	-	-	-	-	-	-	-	144	144
	Total Solar	-	-	146	59	67	272	-	-	-	37	-	1,259	-	-	-	-	-	400	897	12	580	3,149
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	-	123.3	8.2	-	12.0	22.3	-	15.3	-	134.8	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	68	116
	Energy Efficiency, UT	58	67	67	68	69	66	67	68	65	62	54	54	52	50	49	36	32	26	23	24	657	1,057
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	19	18	15	14	13	12	11	9	8	7	5	5	147	248
	Energy Efficiency Total	74	83	85	88	91	89	91	93	91	87	76	75	72	68	66	49	45	36	31	32	872	1,421
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	435.0	-	-	-	-	-	-	-	-	135	615	435	1,185
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	285.0	-	-	-	-	-	-	-	-	-	-	285.0	285.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	540.0	15.0	-	555.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	78	258	300	270	281	267	270	300	300	300	300	8	146
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	SCCT Frame YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	233	-	-	233
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	455	-	-	676
	Utility Solar - PV - S-Oregon	-	-	-	-	-	421	-	-	-	-	-	-	-	375	-	-	-	-	-	-	421	796
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - jbridger	-	-	-	-	-	-	-	-	-	-	354	-	-	-	359	-	-	-	-	-	-	713
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	702	-	702
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	79	-	-	-	-	-	-	-	100	-	-	-	-	-	-	79	179
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	197	-	-	197
	Total Solar	-	-	-	-	-	905	-	-	-	-	354	-	100	475	359	-	-	-	197	702	905	3,092
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	4.1	-	-	-	9.2	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	18.6	-	-	-	41.8	-	-	-	76.9	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	41	39	39	43	41	39	37	33	31	30	29	26	26	24	25	22	22	392	657
	Energy Efficiency, WA	11	9	10	10	12	12	12	11	11	10	9	9	8	8	8	6	6	5	4	4	108	174
	Energy Efficiency Total	52	48	48	53	53	52	56	54	52	49	44	42	40	38	35	33	32	30	27	27	517	864
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	120	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	15	15
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	165	-	-	-	-	-	-	-	-	-	-	165	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	959	581	640	673	179	175	181	254	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,044	979	1,075	1,075	572	817
	FOT West - Winter	151	131	268	303	314	225	232	233	283	415	405	369	421	426	129	51	68	67	-	-	256	225
	Existing Plant Retirements/Conversions	-	(308)	(186)	(224)	(1)	(62)	-	(535)	(85)	(912)	(444)	(506)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	131	294	199	221	3,238	155	154	142	1,298	1,236	2,629	396	593	1,300	82	92	467	2,493	1,424		
	Annual Additions, Short Term Resources	1,149	1,090	850	943	987	405	407	414	537	1,567	1,738	1,744	1,766	1,782	1,471	1,395	1,412	1,347	1,375	1,375		
	Total Annual Additions	1,279	1,222	1,144	1,143	1,207	3,643	562	568	679	2,865	2,975	4,373	2,162	2,375	2,771	1,477	1,503	1,813	3,868	2,799		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-04	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370	370
	Total SCCT	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370	370
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	232	388	-	-	-	-	-	-	-	-	-	232	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,088	-	-	-	-	-	-	-	-	-	1,088
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	232	388	1,088	-	-	-	-	-	-	-	-	2,152	3,628
	Utility Solar - PV - Utah-S	-	-	22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	22	422
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	278	-	-	-	-	-	-	-	452	48	-	-	-	-	-	-	278	778
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	12
	Utility Solar - PV - Naughton	-	-	-	-	-	637	-	-	-	-	-	-	-	-	-	-	-	-	-	-	637	637
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	897	12	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	94	-	-	-	-	-	-	-	-	-	94
	Utility Solar+Storage - PV - Utah-N	-	-	136	64	7	600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	806	806
	Total Solar	-	-	157	64	285	1,337	-	-	-	-	-	94	452	60	-	-	-	400	897	12	1,843	3,758
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	79.4	-	-	-	-	37.3	-	-	8.2	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	-	37.3
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	89.2	-	8.2	7.2	-	37.3	6.7	-	8.2	6.8	27.4	-	15.3	-	132.7	21.6	161.2	380.1
	Energy Efficiency, ID	6	6	7	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	70	117
	Energy Efficiency, UT	58	67	69	73	75	66	67	66	65	62	54	54	52	50	49	36	32	26	23	26	668	1,070
	Energy Efficiency, WY	10	12	13	15	18	16	16	18	19	18	15	14	13	12	11	9	8	7	5	5	154	254
	Energy Efficiency Total	74	85	88	95	100	89	91	91	91	87	76	74	71	67	65	49	45	36	31	35	891	1,441
	Battery Storage - Utah-N	-	-	-	-	240.0	-	-	-	-	60.0	-	-	-	-	-	-	-	-	240	435	300	975
	Battery Storage - WYSW	-	-	-	-	210.0	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	285.0	210.0	510.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	270.0	120.0	-	390.0
	FOT East - Summer	-	-	-	-	295	-	-	-	-	300	282	293	245	292	293	295	300	300	300	300	60	175
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	221	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	221	-	-	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - jbridger	-	-	-	-	713	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	713	713
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	702	-	702
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	475
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Solar	-	-	-	-	713	905	-	-	-	-	-	-	100	-	475	-	-	-	430	702	1,618	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.8	-	-	-	-	-	-	26.8
	Demand Response, OR-Irrigate	-	-	-	-	9.2	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	-	-	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	5.2	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	11.3	-	-	-	-	-	-	-	-	-	5.3	-	-	-	-	-	11.3	16.6
	Demand Response Total	-	-	-	-	25.7	-	-	-	-	24.0	-	-	-	-	42.0	-	3.1	-	32.5	-	49.7	127.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	19	34
	Energy Efficiency, OR	40	43	43	49	47	39	43	41	39	37	33	31	30	29	26	26	26	26	25	24	419	693
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	113	180
	Energy Efficiency Total	52	56	56	63	61	52	56	54	52	49	44	42	40	38	35	34	33	32	30	29	550	907
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	450	60	-	510
	Battery Storage - Willamette Valley	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	60	120
	Battery Storage - Portland NC	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	-	105	75	30	210
	Battery Storage - Walla Walla	-	-	-	-	195	-	-	-	-	-	-	-	-	-	-	-	-	-	-	180	195	375
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	958	559	589	1,075	903	995	969	1,027	1,075	1,075	1,075	1,075	1,075	1,075	1,075	953	889	1,075	1,075	915	980
	FOT West - Winter	151	131	265	299	309	274	280	281	328	340	361	360	385	336	29	-	-	-	-	-	266	206
	Existing Plant Retirements/Conversions	-	(308)	(573)	(224)	(1,065)	(62)	-	(148)	(3)	(764)	(93)	(149)	(350)	(114)	(557)	(156)	(117)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	141	317	222	2,114	4,304	155	152	142	860	514	1,297	672	172	866	83	318	469	2,633	2,014		
	Annual Additions, Short Term Resources	1,149	1,089	824	888	1,680	1,176	1,275	1,251	1,355	1,715	1,717	1,728	1,706	1,703	1,397	1,370	1,253	1,189	1,375	1,375		
	Total Annual Additions	1,279	1,230	1,140	1,110	3,794	5,480	1,430	1,403	1,497	2,575	2,232	3,025	2,378	1,875	2,263	1,453	1,570	1,658	4,008	3,389		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-05	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	(238)	-	-	-	-	-	-	-	-	-	-	-	(119)	-	-	-	-	-	(238)	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370	370
	Total SCCT	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370	370
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	620	-	1,100	-	-	-	-	-	-	-	-	2,540	3,640
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	29	-	-	-	400	-	-	-	429
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	300	-	-	-	-	-	-	-	-	471	-	-	-	-	-	-	300	771
	Utility Solar - PV - Naughton	-	-	-	-	425	212	-	-	-	-	-	-	-	-	-	-	-	-	-	-	637	637
	Utility Solar - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19	-	-	19
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	890	-	-	890
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	77	600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	802	912	-	-	-	-	-	-	-	500	-	-	-	400	909	-	1,937	3,746
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	31.8	-	-	-	-	-	-	-	-	-	-	-	-	-	42.3	2.6	31.8	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	79.4	-	-	-	-	37.3	-	-	8.2	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	12.9	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	1.2	12.9	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	134.0	-	8.2	7.2	-	37.3	6.7	-	8.2	6.8	14.6	-	15.3	-	103.0	21.6	205.9	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	69	71	66	65	65	62	62	57	54	52	50	49	36	33	26	22	24	652	1,055
	Energy Efficiency, WY	10	12	13	14	16	16	16	17	18	18	16	14	13	12	11	9	8	7	5	5	149	250
	Energy Efficiency Total	74	85	86	90	95	89	89	88	86	87	80	74	71	67	65	49	46	36	30	32	870	1,421
	Battery Storage - Utah-N	-	-	-	-	240.0	-	-	-	-	-	45.0	-	-	-	-	-	-	-	285	435	240	1,005
	Battery Storage - WYSW	-	-	-	-	60.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	375.0	60.0	435.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	225.0	-	-	225.0
	FOT East - Summer	-	-	-	-	295	-	-	-	-	300	183	197	264	205	223	225	300	300	300	300	60	155
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90	-	-	-	-	-	-	90
	Utility Solar - PV - Yakima	-	-	-	-	-	228	-	-	-	-	-	-	-	-	-	-	-	-	-	-	228	228
	Utility Solar - PV - jbridger	-	-	-	-	275	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13	275	288
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	438	-	-	-	-	-	-	-	-	-	-	-	-	-	-	330	438	768
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	385	-	-	-	-	-	500	885
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	177	-	-	-	-	-	-	-	-	-	-	-	-	430	-	177	607
	Total Solar	-	-	-	-	713	905	-	-	-	-	-	-	-	100	475	-	-	-	430	343	1,618	2,966
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	30.3	-	-	-	-	-	-	-	-	-	5.4	-	-	-	-	2.0	30.3	37.7
	Demand Response, OR-Irrigate	-	-	-	-	9.2	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	4.3	-	-	-	-	-	-	-	-	-	5.5	-	-	-	-	-	4.3	9.9
	Demand Response, WA-Irrigate	-	-	-	-	5.2	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	11.3	-	-	-	-	3.3	-	-	-	-	2.0	-	-	-	-	-	14.6	16.6
	Demand Response Total	-	-	-	-	60.3	-	-	-	-	27.3	-	-	-	-	13.0	-	3.1	-	33.6	2.0	87.6	139.3
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	43	43	42	47	39	36	41	39	37	33	31	30	29	26	27	26	26	24	24	405	679
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	10	10	9	9	8	8	6	6	5	4	4	112	180
	Energy Efficiency Total	52	55	55	55	61	52	50	54	52	49	45	42	40	38	35	34	33	32	29	29	534	891
	Battery Storage - S-Oregon	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	-	-	-	390	-	15	405
	Battery Storage - Willamette Valley	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	105	165
	Battery Storage - Portland NC	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	30	105	60	195
	Battery Storage - Walla Walla	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	165	105	270
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	955	777	806	1,075	808	899	873	931	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,011	1,075	1,075	920	994
	FOT West - Winter	151	131	265	299	307	113	118	119	166	178	198	198	196	175	114	57	-	-	-	-	185	139
	Existing Plant Retirements/Conversions	-	(308)	(810)	(224)	(1,065)	(62)	-	(148)	(3)	(764)	(93)	(149)	(350)	(114)	(320)	(156)	(117)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	140	316	209	2,555	3,879	147	150	138	1,190	176	1,216	120	712	603	83	97	468	2,907	1,568		
	Annual Additions, Short Term Resources	1,149	1,086	1,042	1,105	1,677	921	1,016	992	1,097	1,553	1,456	1,469	1,535	1,455	1,412	1,357	1,375	1,311	1,375	1,375		
	Total Annual Additions	1,279	1,226	1,358	1,314	4,231	4,800	1,163	1,142	1,234	2,743	1,632	2,685	1,655	2,167	2,015	1,440	1,472	1,780	4,282	2,943		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-06	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	(238)	-	-	-	-	-	-	-	-	-	-	-	(119)	-	-	-	-	-	(238)	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	555	-	-	370	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	345	275	-	-	-	-	-	-	-	-	-	345	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,083	17	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	345	275	1,083	17	-	-	-	-	-	-	-	2,265	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	-	27	-	-	-	-	-	-	-	-	-	-	-	400	-	-	232	632
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	68	-	-	-	-	-	341	159	-	-	-	-	-	-	-	68	568
	Utility Solar - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	8
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	901	-	-	901
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	900	-	-	-	-	-	-	-	-	-	900
	Total Solar	-	-	146	59	-	195	-	-	-	-	-	1,241	159	-	-	-	-	400	909	-	400	3,109
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	1.2
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	-	-	7.0	-	144.9	21.6	161.2	361.7
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	69	71	75	66	67	65	65	62	54	53	52	50	49	36	32	26	25	26	665	1,068
	Energy Efficiency, WY	10	12	13	14	18	16	16	17	18	18	15	14	13	12	11	9	8	7	5	5	152	252
	Energy Efficiency Total	74	85	88	93	100	89	91	89	89	87	76	74	71	67	65	49	45	37	33	35	886	1,437
	Battery Storage - Utah-N	-	-	-	-	75.0	-	-	-	-	90.0	-	-	-	-	-	-	-	-	270	435	165	870
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	315.0	-	-	-	-	-	-	-	-	-	90.0	315.0	405.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195.0	120.0	-	315.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	300	300	300	300	300	266	269	300	300	300	300	30	162
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	95	-	-	-	-	-	-	-	500	595
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	49	405	454
	Utility Solar - PV - jbridger	-	-	-	-	354	-	-	-	-	-	-	-	-	-	359	-	-	-	-	26	354	739
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	676	-	676
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	162	218	-	-	-	-	-	-	-	380
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	381	-	381
	Total Solar	-	-	-	-	354	905	-	-	-	-	-	-	357	218	359	-	-	-	-	1,132	1,259	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.3	-	-	30.3
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	-	4.1
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	3.1
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	-	-	4.1	-	-	-	-	-	76.9	-	9.4	90.3
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	43	43	49	47	39	36	41	39	37	33	31	30	29	26	26	26	26	25	24	412	686
	Energy Efficiency, WA	11	11	11	12	12	12	11	11	11	10	9	9	9	8	8	6	6	5	4	4	112	180
	Energy Efficiency Total	52	56	56	63	61	52	49	54	52	49	44	41	40	38	35	33	33	32	30	29	542	899
	Battery Storage - S-Oregon	-	-	-	-	120	-	-	-	-	90	-	-	-	-	-	-	-	-	315	(75)	210	450
	Battery Storage - Willamette Valley	-	-	-	-	60	-	-	-	-	45	-	-	-	-	-	-	-	-	-	60	105	165
	Battery Storage - Portland NC	-	-	-	-	15	-	-	-	-	60	-	-	-	-	-	-	-	-	60	-	75	135
	Battery Storage - Walla Walla	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	-	-	-	-	180	135	315
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	608	662	1,029	480	573	562	620	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,049	984	1,075	1,075	733	898
	FOT West - Winter	151	131	268	303	313	242	249	250	297	429	420	384	414	354	74	-	-	-	-	-	263	214
	Existing Plant Retirements/Conversions	-	(61)	(810)	(224)	(352)	(62)	-	(230)	(3)	(912)	(93)	(753)	(350)	(114)	(676)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	141	305	214	1,035	3,162	148	150	141	1,207	401	3,003	648	336	1,051	82	85	469	2,255	2,027		
	Annual Additions, Short Term Resources	1,149	850	877	965	1,343	722	821	812	917	1,804	1,795	1,759	1,789	1,729	1,415	1,344	1,349	1,284	1,375	1,375		
	Total Annual Additions	1,279	991	1,182	1,179	2,377	3,883	969	962	1,058	3,011	2,197	4,762	2,437	2,065	2,466	1,426	1,434	1,753	3,630	3,402		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-07	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	(238)	-	-	-	-	-	-	-	-	-	-	-	(119)	-	-	-	-	-	(238)	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret. WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	370	555	-	-	-	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,055	-	-	-	-	-	-	-	-	-	1,055
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,055	-	-	-	-	-	-	-	-	1,920	3,595
	Utility Solar - PV - Utah-S	-	-	146	59	-	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	205	605
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	95	-	-	-	-	-	-	500	-	-	-	-	-	-	-	95	595
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	45	-	-	-	-	-	-	-	-	45
	Utility Solar - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	27	-	-	27
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	882	-	-	882
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	900	-	-	-	-	-	-	-	-	-	900
	Total Solar	-	-	146	59	-	195	-	-	-	-	-	900	545	-	-	-	-	400	909	-	400	3,155
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	20.5	-	15.3	-	136.6	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	73	75	68	67	65	63	62	54	54	52	50	49	36	32	26	25	26	665	1,069
	Energy Efficiency, WY	10	12	13	14	18	16	17	17	17	17	15	14	13	12	11	9	8	7	5	5	150	249
	Energy Efficiency Total	74	85	86	93	100	91	91	89	87	87	76	75	71	67	65	49	44	36	33	34	883	1,434
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	615	-	915
	Battery Storage - WYSW	-	-	-	-	150.0	-	-	-	-	300.0	-	-	-	-	-	-	-	-	-	105.0	450.0	555.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300.0	75.0	-	375.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	286	212	296	300	174	298	300	300	300	300	300	29	153
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	90	-	-	-	-	-	-	-	179	-	-	-	-	-	-	90	269
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	372	405	777
	Utility Solar - PV - jbridger	-	-	-	-	354	-	-	-	-	-	359	-	-	-	-	-	-	-	-	24	354	737
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	678	-	678
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	410	-	-	-	-	-	-	-	296	-	-	-	-	-	-	410	706
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	58	-	58
	Total Solar	-	-	-	-	354	905	-	-	-	-	359	-	-	575	-	-	-	-	-	1,132	1,259	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	5.3	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	40.4	-	-	-	10.7	-	-	-	76.9	-	9.4	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	43	43	49	47	39	40	41	39	37	33	31	30	29	26	27	26	26	25	24	417	692
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	11	9	9	8	8	8	6	6	5	4	4	112	180
	Energy Efficiency Total	52	56	55	62	61	52	54	54	52	49	44	42	40	38	35	34	33	32	30	29	547	905
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	225	-	105	330
	Battery Storage - Willamette Valley	-	-	-	-	75	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	105	105
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	105	60	165
	Battery Storage - Walla Walla	-	-	-	-	180	-	-	-	-	-	-	-	-	-	-	-	-	-	-	180	180	360
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	606	660	1,039	411	502	492	549	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,010	1,075	1,075	705	887
	FOT West - Winter	151	131	265	300	310	143	147	149	196	328	323	285	294	244	173	92	109	108	-	-	212	187
	Existing Plant Retirements/Conversions	-	(61)	(810)	(224)	(352)	(62)	-	(230)	(3)	(912)	(449)	(753)	(350)	(114)	(320)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	141	303	214	1,034	3,164	153	150	138	757	1,516	2,634	656	693	132	84	93	469	2,453	2,296		
	Annual Additions, Short Term Resources	1,149	850	871	960	1,349	555	650	641	745	1,689	1,610	1,656	1,669	1,493	1,545	1,467	1,484	1,418	1,375	1,375		
	Total Annual Additions	1,279	991	1,175	1,174	2,383	3,718	803	791	884	2,445	3,126	4,289	2,326	2,186	1,677	1,550	1,576	1,887	3,828	3,671		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-08	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	35	-	-	-	-	-	-	-	-	-	(35)	-	-	-	-	-	-	-	-	35	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	370	-	-	185	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	370	-	-	555	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,100	-	-	-	-	-	-	-	-	1,920	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	67	28	-	-	-	-	-	-	-	-	-	-	-	400	-	-	300	700
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	500
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	11	37	-	729	-	-	-	-	-	-	-	-	47	776
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	124	-	-	-	-	-	-	-	-	-	-	-	-	-	-	124	124
	Total Solar	-	-	146	59	67	252	-	-	11	37	-	729	500	-	-	-	-	400	909	-	571	3,109
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	-	123.3	8.2	-	12.0	22.3	-	15.3	-	134.8	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	68	67	68	65	62	54	56	52	50	49	36	32	26	25	26	659	1,065
	Energy Efficiency, WY	10	10	11	14	15	16	17	18	19	18	15	14	13	12	11	9	8	7	6	6	149	251
	Energy Efficiency Total	74	83	85	88	91	92	92	94	91	87	76	76	72	68	66	49	45	37	33	35	876	1,433
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	300.0	-	-	-	-	-	-	-	-	330	330	300	960
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	165.0	-	-	-	-	-	-	-	-	225.0	45.0	165.0	435.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	210.0	210.0	-	420.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	101	298	292	300	261	227	229	300	300	300	300	10	145
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	114	14	-	-	-	-	-	-	-	500	628
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	31	405	436
	Utility Solar - PV - jbridger	-	-	-	-	-	-	-	-	-	-	354	-	-	-	298	-	-	-	-	-	-	652
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	61	-	-	-	-	343	-	404
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	346	-	-	-	-	-	-	-	346
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	399	-	399
	Total Solar	-	-	-	-	-	905	-	-	-	-	354	114	14	446	359	-	-	-	-	773	905	2,966
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	9.4	-	-	51.1	-	-	-	76.9	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	42	39	39	43	41	39	37	33	31	30	29	27	26	26	26	25	24	392	668
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	110	178
	Energy Efficiency Total	52	48	48	55	53	52	56	54	52	49	44	42	40	38	36	34	33	32	30	29	520	879
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	-	-	30	-	210	240
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	120	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	75	75
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	45	-	120	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	925	547	606	639	227	223	224	278	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,004	939	1,075	1,075	574	814
	FOT West - Winter	151	131	268	303	314	248	254	256	305	437	428	436	441	379	83	3	20	20	-	-	267	224
	Existing Plant Retirements/Conversions	-	(273)	(186)	(224)	(1)	(62)	-	(535)	(85)	(912)	(444)	(541)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	132	294	201	221	3,221	156	155	153	1,268	1,217	2,449	626	565	1,311	83	93	469	2,245	1,443		
	Annual Additions, Short Term Resources	1,149	1,056	816	909	953	475	477	480	583	1,613	1,801	1,804	1,816	1,715	1,385	1,307	1,324	1,259	1,375	1,375		
	Total Annual Additions	1,279	1,188	1,110	1,110	1,174	3,696	633	635	736	2,881	3,019	4,252	2,442	2,280	2,696	1,390	1,417	1,728	3,620	2,818		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-09	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret. WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	370	-	-	185	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	370	-	-	555	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,083	-	-	-	-	-	-	-	-	-	1,083
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,083	-	-	-	-	-	-	-	-	1,920	3,623
	Utility Solar - PV - Utah-S	-	-	146	59	67	28	-	-	-	-	-	-	-	-	-	-	-	400	-	-	300	700
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	500
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	-	-	-	-	-	-	17
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	897	12	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	37	-	729	-	-	-	-	-	-	-	-	37	765
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135	135
	Total Solar	-	-	146	59	67	263	-	-	-	37	-	729	517	-	-	-	-	400	897	12	571	3,126
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	124.9	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	6.7	124.9	-	12.0	22.3	-	15.3	-	134.8	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	68	116
	Energy Efficiency, UT	58	67	67	68	69	68	67	68	65	62	54	54	52	50	49	36	32	26	25	26	659	1,063
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	19	18	15	14	13	12	11	9	8	7	5	5	147	248
	Energy Efficiency Total	74	83	85	88	91	92	91	93	91	87	76	74	71	68	66	49	45	37	33	35	874	1,427
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	405.0	-	-	-	-	-	-	-	-	60	225	405	690
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	45.0	-	-	-	-	-	-	-	-	-	300.0	45.0	345.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	225.0	60.0	-	285.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	-	131	294	300	290	269	271	300	300	300	300	-	138
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	482	-	-	-	-	-	-	-	276	-	-	-	-	-	-	482	758
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - jbridger	-	-	-	-	-	-	-	-	-	-	354	-	-	-	359	-	-	-	-	-	-	713
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	702	-	702
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	18	-	-	-	-	-	-	-	199	-	-	-	-	-	-	18	217
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	-	430
	Total Solar	-	-	-	-	-	905	-	-	-	-	354	-	100	475	359	-	-	430	-	702	905	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	1	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	9.4	-	-	51.1	-	-	-	76.9	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	32	37	36	39	39	36	41	39	37	33	31	30	29	26	26	26	25	25	23	375	646
	Energy Efficiency, WA	11	9	10	10	11	12	11	11	11	10	9	9	8	8	8	6	6	5	4	4	107	175
	Energy Efficiency Total	52	43	48	48	52	52	49	54	52	49	44	41	40	38	35	33	33	31	30	28	499	853
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	-	-	435	-	210	645
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	195	-	-	-	-	-	-	-	-	15	-	195	210
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	-	45	-	135	180
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	190	185	187	233	930	1,075	1,075	1,075	1,075	1,075	1,075	1,046	870	1,075	1,075	494	773
	FOT West - Winter	151	131	268	303	314	240	246	248	297	429	420	383	436	417	119	41	58	-	-	-	263	225
	Existing Plant Retirements/Conversions	-	(61)	(186)	(224)	(1)	(62)	-	(535)	(85)	(912)	(444)	(753)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	126	286	194	229	3,231	148	154	142	1,268	1,101	2,431	728	593	1,309	82	93	898	2,172	1,383		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	430	432	434	530	1,360	1,626	1,752	1,811	1,782	1,463	1,387	1,404	1,170	1,375	1,375		
	Total Annual Additions	1,279	977	1,048	1,000	1,041	3,661	580	589	672	2,627	2,727	4,184	2,539	2,375	2,772	1,470	1,497	2,068	3,547	2,758		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

		Capacity (MW)																				Resource Totals 1/	
	P-10	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	185	-	-	-	-	-	-	-	-	-	185
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	185	-	-	-	185	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	185	185	-	-	185	-	-	-	-	-	-	555
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	536	84	-	-	-	-	-	-	-	-	-	536	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,090	-	-	-	-	-	-	-	-	-	1,090
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	536	84	1,090	-	-	-	-	-	-	-	-	2,456	3,630
	Utility Solar - PV - Utah-S	-	-	146	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	146	546
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	33	121	-	-	-	-	-	-	-	500	-	-	-	-	-	-	154	654
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	10
	Utility Solar - PV - Naughton	-	-	-	-	357	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	357	357
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	231	-	-	-	-	-	-	-	-	-	231
	Utility Solar+Storage - PV - Utah-N	-	-	-	64	5	600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	669	669
	Total Solar	-	-	146	64	395	821	-	-	-	-	-	231	10	500	-	-	-	400	909	-	1,426	3,476
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	79.4	-	-	-	-	37.3	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	97.5	-	8.2	7.2	-	37.3	6.7	8.2	-	12.0	22.3	-	15.3	-	134.8	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	70	118
	Energy Efficiency, UT	58	67	67	72	75	66	67	68	65	62	54	53	52	50	49	36	32	26	25	26	667	1,071
	Energy Efficiency, WY	10	12	13	14	18	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	153	253
	Energy Efficiency Total	74	85	86	93	100	90	91	93	91	87	76	74	71	68	65	49	45	37	33	35	890	1,441
	Battery Storage - Utah-N	-	-	-	-	270.0	-	-	-	-	15.0	-	-	-	-	-	-	-	-	255	405	285	945
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	210.0	-	-	-	-	-	-	-	-	195.0	-	210.0	405.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195.0	240.0	-	435.0
	FOT East - Summer	-	-	-	-	295	-	-	-	-	300	150	230	300	231	298	300	300	300	300	300	60	165
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	288	-	-	-	-	-	-	-	-	62	-	-	-	-	-	288	350
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	141	-	-	-	405	546
	Utility Solar - PV - jbridger	-	-	-	-	713	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	713	761
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	654	-	654
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	212	-	-	-	-	-	-	-	-	413	-	-	-	-	-	212	625
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	267	22	-	-	-	289
	Total Solar	-	-	-	-	713	905	-	-	-	-	-	-	-	100	475	-	408	22	-	702	1,618	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	4.1	-	-	-	9.2	-	-	-	-	-	-	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	3.1	-	-	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	11.8	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	24.7	-	-	-	26.4	-	3.1	-	44.3	-	9.4	107.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	19	34
	Energy Efficiency, OR	40	43	43	49	47	39	43	41	39	37	33	31	30	29	27	26	26	26	25	24	419	694
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	113	181
	Energy Efficiency Total	52	56	56	63	61	52	56	54	52	49	44	42	40	38	36	33	33	32	30	29	550	908
	Battery Storage - S-Oregon	-	-	-	-	165	-	-	-	-	45	-	-	-	-	-	-	-	-	105	15	210	330
	Battery Storage - Willamette Valley	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	30	60
	Battery Storage - Portland NC	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	-	-	60	105	45	210
	Battery Storage - Walla Walla	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	-	-	105	60	45	210
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	1,075	616	709	684	741	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,005	1,075	1,075	761	914
	FOT West - Winter	151	131	265	299	310	188	194	196	243	255	252	274	266	250	181	125	23	-	-	-	223	180
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1,065)	(62)	-	(148)	(3)	(764)	(93)	(396)	(350)	(114)	(557)	(156)	(117)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	141	295	219	2,026	3,788	156	155	142	989	420	1,630	121	718	810	82	505	490	2,509	1,642		
	Annual Additions, Short Term Resources	1,149	850	757	800	1,680	804	904	879	984	1,630	1,477	1,579	1,641	1,555	1,554	1,500	1,397	1,305	1,375	1,375		
	Total Annual Additions	1,279	990	1,052	1,019	3,707	4,592	1,059	1,034	1,126	2,619	1,897	3,209	1,762	2,274	2,364	1,583	1,902	1,795	3,884	3,017		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-11	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret. WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	185	185	-	185	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	185	185	-	555	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	33	33	554	-	-	-	-	-	-	-	-	33	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,096	-	-	-	-	-	-	-	-	-	1,096
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	33	33	1,650	-	-	-	-	-	-	-	-	1,953	3,636
	Utility Solar - PV - Utah-S	-	-	146	59	67	28	-	-	-	-	-	-	-	-	-	-	-	400	-	-	300	700
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	-	500
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	897	12	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	37	-	729	-	-	-	-	-	-	-	-	37	765
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135	135
	Total Solar	-	-	146	59	67	263	-	-	-	37	-	1,233	-	-	-	-	-	400	897	12	571	3,113
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	124.9	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	6.7	124.9	-	12.0	22.3	-	15.3	-	134.8	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	68	67	68	65	62	54	56	52	50	49	36	32	26	25	26	659	1,065
	Energy Efficiency, WY	10	10	11	14	15	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	149	250
	Energy Efficiency Total	74	83	85	88	91	92	92	94	91	87	76	76	72	68	66	49	45	37	33	35	876	1,432
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	240.0	-	-	-	-	-	-	-	-	285	390	240	915
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	240.0	-	-	-	-	-	-	-	-	15.0	150.0	240.0	405.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	255.0	75.0	-	330.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	-	189	300	270	300	279	281	300	300	300	300	-	141
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	325	-	-	-	-	-	-	-	469	-	-	-	-	-	-	325	794
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	81	-	-	405	486
	Utility Solar - PV - jbridger	-	-	-	-	-	-	-	-	-	-	354	-	-	-	359	-	-	-	-	-	-	713
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	702	-	702
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	175	-	-	-	-	-	-	-	6	-	-	-	-	-	-	175	181
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	349	-	-	-	349
	Total Solar	-	-	-	-	-	905	-	-	-	-	354	-	100	475	359	-	-	430	-	702	905	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	9.4	-	-	51.1	-	-	-	76.9	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	42	39	39	43	41	39	37	33	31	30	29	27	26	26	26	25	24	392	668
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	110	178
	Energy Efficiency Total	52	49	48	55	53	52	56	54	52	49	44	42	40	38	36	33	33	32	30	29	520	878
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	-	-	165	-	210	375
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	120	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	15	-	75	90
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	-	30	-	135	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	157	153	154	200	892	1,075	1,075	1,075	1,075	1,075	1,075	1,055	896	1,075	1,075	477	766
	FOT West - Winter	151	131	268	303	314	202	209	210	259	391	382	346	398	425	128	50	67	-	-	-	244	212
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(148)	(85)	(912)	(444)	(753)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	132	286	201	229	3,232	156	155	142	1,331	514	3,320	397	593	1,311	82	93	899	2,158	1,414		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	359	361	364	459	1,284	1,646	1,721	1,743	1,800	1,482	1,406	1,422	1,196	1,375	1,375		
	Total Annual Additions	1,279	982	1,048	1,007	1,041	3,591	517	519	602	2,615	2,159	5,041	2,139	2,394	2,793	1,488	1,516	2,095	3,533	2,789		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

		Capacity (MW)																				Resource Totals 1/	
	P-12	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	(238)	-	-	-	-	-	-	-	-	-	-	-	(119)	-	-	-	-	-	(238)	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	185	-	185	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	185	555	185	-	-	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,100	-	-	-	-	-	-	-	-	1,920	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	-	31	-	-	-	-	-	91	-	-	-	-	-	400	-	-	236	727
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	64	-	-	-	-	-	400	9	-	-	-	-	-	-	-	64	473
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	715	-	-	715
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	312	-	-	-	-	-	-	-	-	-	312
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	588	-	-	-	-	-	-	-	-	-	-	-	-	-	-	588	588
	Total Solar	-	-	146	59	-	783	-	-	-	-	-	803	9	-	-	-	-	400	715	-	988	2,915
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	20.5	-	15.3	-	136.6	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	70	117
	Energy Efficiency, UT	58	67	67	69	75	68	67	68	65	62	54	53	52	50	49	36	34	26	24	22	667	1,066
	Energy Efficiency, WY	10	12	13	14	18	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	154	254
	Energy Efficiency Total	74	85	86	90	100	92	92	94	91	87	76	74	71	67	65	49	46	37	32	30	891	1,438
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	360	375	-	735
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	420.0	-	-	-	-	-	-	-	-	-	120.0	420.0	540.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	255.0	150.0	-	405.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	212	300	300	273	174	298	300	300	300	300	300	21	153
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	95	-	-	-	-	-	-	500	595
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	10	-	405	415
	Utility Solar - PV - jbridger	-	-	-	-	354	-	-	-	-	-	359	-	-	-	-	-	-	-	-	48	354	761
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	654	-	654
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	380	-	-	-	-	-	-	-	380
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	-	-	420
	Total Solar	-	-	-	-	354	905	-	-	-	-	359	-	-	575	-	-	-	-	430	702	1,259	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	5.3	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	40.4	-	-	-	10.7	-	-	-	76.9	-	9.4	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	19	33
	Energy Efficiency, OR	40	43	43	47	47	39	43	41	39	37	33	31	30	29	26	26	24	25	22	21	417	682
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	11	9	9	8	8	8	6	6	5	4	4	113	179
	Energy Efficiency Total	52	56	56	60	61	52	56	54	52	49	44	42	40	38	35	33	31	30	27	26	548	895
	Battery Storage - S-Oregon	-	-	-	-	45	-	-	-	-	105	-	-	-	-	-	-	-	-	120	45	150	315
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	180	-	-	-	-	-	-	-	-	-	15	180	195
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	-	-	30	135	165
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	571	629	1,007	300	393	418	476	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	1,010	1,075	1,075	659	864
	FOT West - Winter	151	131	265	300	310	239	243	245	291	423	420	381	390	360	288	194	212	211	-	-	260	253
	Existing Plant Retirements/Conversions	-	(61)	(423)	(224)	(352)	(62)	-	(617)	(3)	(912)	(449)	(753)	(350)	(114)	(320)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	141	304	209	675	3,752	156	155	142	1,102	1,331	2,581	305	693	132	83	93	467	2,595	1,514		
	Annual Additions, Short Term Resources	1,149	850	836	929	1,318	539	636	663	767	1,711	1,795	1,756	1,738	1,609	1,661	1,569	1,586	1,521	1,375	1,375		
	Total Annual Additions	1,279	991	1,140	1,137	1,992	4,291	792	818	910	2,813	3,126	4,337	2,043	2,302	1,792	1,652	1,679	1,988	3,970	2,889		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-13	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	-	-	185	370	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	185	370	-	-	-	370	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,099	-	-	-	-	-	-	-	-	-	1,099
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,099	-	-	-	-	-	-	-	-	1,920	3,639
	Utility Solar - PV - Utah-S	-	-	146	59	67	28	-	-	-	-	-	-	-	-	-	-	-	400	-	-	300	700
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	500
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	40	37	3	726	-	-	-	-	-	-	-	-	76	805
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	95	95
	Total Solar	-	-	146	59	67	223	-	-	40	37	3	726	500	-	-	-	-	400	-	909	571	3,109
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Themostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	124.9	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Themostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	6.7	124.9	-	12.0	-	-	15.3	-	157.1	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	68	115
	Energy Efficiency, UT	58	67	67	68	69	68	67	68	65	62	54	53	52	50	49	36	32	26	20	22	659	1,053
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	19	18	15	14	13	12	11	9	8	7	5	5	147	247
	Energy Efficiency Total	74	83	85	88	91	91	91	93	91	87	76	74	71	68	65	49	45	36	28	30	873	1,415
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	315.0	-	-	-	-	-	-	-	-	-	525	315	840
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	405.0	-	-	-	-	-	-	-	-	-	-	405.0	405.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300.0	-	300.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	-	-	300	289	165	219	221	300	300	300	300	-	120
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	-	(351)
	JimBridger 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	403	-	-	-	-	-	-	-	500	903
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,056	-	1,056
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	72	-	-	-	-	-	-	-	72
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Solar	-	-	-	-	-	905	-	-	-	-	-	-	503	72	-	-	-	-	430	1,056	905	2,966
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Themostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Themostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	128.0	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	32
	Energy Efficiency, OR	40	32	37	42	39	39	36	41	39	37	33	31	30	29	26	26	26	26	22	21	381	649
	Energy Efficiency, WA	11	9	10	10	12	12	12	11	11	10	9	9	8	8	8	6	6	5	4	4	108	175
	Energy Efficiency Total	52	43	48	54	53	52	50	54	52	49	44	41	40	38	35	33	33	32	27	26	507	857
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	345	15	360
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	120	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	135	135
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	135	135
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	182	177	179	225	946	889	1,075	1,075	1,075	1,075	1,075	996	931	1,052	1,075	492	762
	FOT West - Winter	151	131	268	303	314	243	249	251	300	432	423	387	476	451	386	299	316	301	-	-	264	284
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(148)	(85)	(912)	(93)	(753)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(1,451)		
	Annual Additions, Long Term Resources	130	126	286	200	229	3,191	149	154	182	1,403	750	2,074	1,114	375	470	82	93	468	1,583	3,212		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	425	427	430	526	1,378	1,312	1,762	1,839	1,691	1,680	1,595	1,611	1,532	1,352	1,375		
	Total Annual Additions	1,279	977	1,048	1,006	1,041	3,616	576	585	707	2,781	2,062	3,836	2,953	2,066	2,150	1,677	1,704	2,000	2,935	4,587		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-14	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gads by 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	185	-	-	185	-	-	-	-	-	-	370
	SCCT Frame UTN	-	-	-	-	195	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195	195
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370	370
	Total SCCT	-	-	-	-	195	-	-	-	-	370	-	185	-	-	185	-	-	-	-	-	564	934
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	222	398	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	222	1,498	-	-	-	-	-	-	-	-	1,920	3,640
	Utility Solar - PV - Utah-S	-	-	146	-	-	154	-	-	-	-	-	-	289	-	-	-	-	400	-	-	300	989
	Utility Solar - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	211	-	-	-	-	-	-	-	-	211
	Utility Solar - PV - Naughton	-	-	-	-	172	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	172
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	901	8	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	-	64	42	600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	706	706
	Total Solar	-	-	146	64	214	754	-	-	-	-	-	-	500	-	-	100	-	400	901	8	1,178	3,087
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	5.3	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	31.8	-	-	-	-	-	-	-	-	-	-	-	-	-	42.3	2.6	31.8	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	79.4	-	-	-	-	37.3	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	3.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	3.4	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	27.1	-	-	-	-	-	-	-	-	-	-	-	-	-	12.3	-	27.1	39.4
	Demand Response, WY-Thermostat	-	-	-	-	12.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	12.9	14.1
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	178.0	-	8.2	7.2	-	37.3	6.7	8.2	-	12.0	-	-	15.3	-	69.0	21.6	241.7	374.6
	Energy Efficiency, ID	6	6	7	7	8	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	70	119
	Energy Efficiency, UT	58	67	69	72	75	68	67	68	65	65	54	56	52	50	51	36	32	26	23	25	674	1,080
	Energy Efficiency, WY	10	10	13	14	15	16	16	18	19	18	14	14	13	12	11	9	8	7	5	5	149	248
	Energy Efficiency Total	74	83	88	93	98	92	91	93	91	90	75	77	71	68	68	49	45	36	31	34	893	1,447
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	150.0	-	-	-	-	-	-	-	15	480	45	150	690
	Battery Storage - WYSW	-	-	-	-	60.0	-	-	-	-	90.0	-	-	-	-	15.0	-	-	-	300.0	15.0	150.0	480.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	-	-	210.0	30.0	-	255.0
	FOT East - Summer	-	-	-	-	20	-	-	-	-	224	233	255	284	298	288	287	300	300	300	300	24	154
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	221	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	499	-	-	-	-	-	-	184	-	-	-	-	-	-	-	499	684
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - jbridger	-	-	-	-	561	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	561	561
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	495	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	495	495
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	145	145	-	-	-	-	-	-	-	291
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	430
	Total Solar	-	-	-	-	1,056	904	-	-	-	-	-	-	330	245	-	-	-	-	-	430	1,960	2,965
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	15.9	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	-	15.9	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	30.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.0	30.3	32.3
	Demand Response, OR-Irrigate	-	-	-	-	9.2	-	-	-	-	4.1	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, OR-Thermostat	-	-	-	-	41.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	41.2	41.2
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	4.3	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	1.1	4.3	10.9
	Demand Response, WA-Irrigate	-	-	-	-	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	11.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.3	11.3
	Demand Response Total	-	-	-	-	117.5	-	-	-	-	24.0	-	-	-	-	-	-	-	-	26.4	3.0	141.5	170.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	43	43	49	47	46	43	41	39	37	33	31	30	30	27	26	25	26	24	23	426	699
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	113	181
	Energy Efficiency Total	52	56	55	63	61	59	56	54	52	49	44	42	40	40	36	33	32	32	29	28	557	913
	Battery Storage - S-Oregon	-	-	-	-	300	-	-	-	-	180	-	-	-	-	-	-	-	-	-	(75)	480	405
	Battery Storage - Willamette Valley	-	-	-	-	45	-	-	-	-	60	-	-	-	-	-	-	-	-	15	-	105	120
	Battery Storage - Portland NC	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	-	-	-	15	120	75	210
	Battery Storage - Walla Walla	-	-	-	-	120	-	-	-	-	15	-	-	-	-	-	-	-	-	-	165	135	300
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	713	486	491	1,075	632	724	697	769	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,062	997	1,075	1,075	766	916
	FOT West - Winter	151	127	257	285	419	378	383	396	443	600	607	558	602	499	27	3	-	-	-	-	344	287
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1,767)	(62)	-	(148)	(85)	(912)	(93)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	139	297	220	2,623	3,729	156	154	142	1,065	349	1,809	941	365	541	182	92	483	2,298	824		
	Annual Additions, Short Term Resources	1,149	840	743	776	1,514	1,010	1,106	1,093	1,212	1,899	1,915	1,888	1,961	1,873	1,390	1,365	1,362	1,297	1,375	1,375		
	Total Annual Additions	1,279	979	1,040	996	4,138	4,739	1,262	1,248	1,354	2,964	2,264	3,697	2,902	2,238	1,932	1,547	1,454	1,781	3,673	2,199		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-15	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	-	-	-	-	(44)	(44)
	Hayden 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	(33)
	Hunter 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(418)	-	-	-	-	-	-	-	-	-	-	(418)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	(269)
	Hunter 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(471)	-	-	-	-	-	-	-	-	(471)
	Huntington 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)
	Huntington 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Wyodak (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	(268)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret. WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - Utah-N - J 1x1	-	-	-	-	-	-	-	-	252	315	-	-	-	-	-	-	-	-	-	-	567	567
	Total CCCT	-	-	-	-	-	-	-	-	252	315	-	-	-	-	-	-	-	-	-	-	567	567
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	370
	SCCT Frame UTS	-	-	-	-	-	-	-	-	-	-	-	-	195	-	-	-	-	-	-	-	-	195
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	370	370	195	-	-	-	-	-	-	-	-	934
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	337	283	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,079	-	-	-	-	-	-	-	-	-	1,079
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	337	1,363	-	-	-	-	-	-	-	-	1,920	3,619
	Utility Solar - PV - Utah-S	-	-	146	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	146	546
	Utility Solar - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	154	-	-	-	-	-	-	306	-	-	-	-	-	-	-	154	459
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	-	-	-	-	-	21
	Utility Solar - PV - Naughton	-	-	-	-	111	156	-	-	-	-	-	-	-	-	-	-	-	-	-	-	267	267
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	265	450	-	-	-	-	-	-	-	-	-	715
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	33	-	-	-	-	-	-	-	-	-	-	33
	Utility Solar+Storage - PV - Utah-N	-	-	-	64	-	236	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Total Solar	-	-	146	64	111	546	-	-	-	-	298	471	406	-	-	-	-	400	-	-	867	2,441
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	-	-	-	-	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	-	-	-	-	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	68.5	-	-	-	-	-	-	2.6	-	71.1
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	116.7	-	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	-	-	-	-	-	-	-	37.3
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	116.7	-	25.4	10.0	120.2	13.8	-	-	15.3	3.7	3.2	21.6	161.2	374.5
	Energy Efficiency, ID	6	7	7	7	8	8	7	7	7	7	7	7	6	6	6	5	4	4	3	3	71	121
	Energy Efficiency, UT	58	69	72	73	75	75	71	74	70	67	62	65	61	58	58	40	40	32	20	23	704	1,162
	Energy Efficiency, WY	10	12	13	14	17	17	17	18	19	18	16	15	13	12	11	9	8	7	5	5	155	258
	Energy Efficiency Total	74	87	92	94	100	99	96	99	96	92	85	87	81	76	75	53	53	43	28	31	929	1,541
	Battery Storage - Utah-N	-	-	-	-	-	105.0	-	435.0	-	-	360.0	120.0	30.0	-	330.0	-	-	-	-	-	540	1,380
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	180.0	-	150.0	-	285.0	60.0	30.0	-	-	-	-	-	180.0	705.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	330.0	-	-	60.0	-	-	-	-	-	-	390.0
	FOT East - Summer	-	-	-	-	-	-	-	71	246	235	300	300	300	300	300	300	300	300	300	300	55	178
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	CCCT - Jbridger - J 1x1	-	-	-	-	-	-	-	-	-	487	-	487	-	-	-	-	-	-	-	-	487	974
	Total CCCT	-	-	-	-	-	-	-	-	-	487	-	487	-	-	-	-	-	-	-	-	487	974
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	-	-	-	-	443
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	2
	Utility Solar - PV - jbridger	-	-	-	-	-	349	-	-	87	-	-	-	-	-	-	-	-	-	-	-	436	436
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	6
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	474	-	-	-	-	-	-	-	500	974
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	428	-	405	833
	Total Solar	-	-	-	-	-	1,254	-	-	87	-	6	-	474	-	100	-	-	-	430	-	1,341	2,351
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	-	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	-	-	5.5
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	-	3.1	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	11.3	-	3.3	-	-	-	-	-	-	-	2.0	-	11.3	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	49.7	-	8.7	-	-	-	-	-	-	-	44.0	-	49.7	102.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	19	34
	Energy Efficiency, OR	40	51	50	49	49	48	43	43	39	37	33	31	30	29	26	26	24	25	22	23	447	714
	Energy Efficiency, WA	11	11	11	12	13	13	12	12	11	10	9	9	9	8	8	6	6	5	4	4	116	182
	Energy Efficiency Total	52	64	63	63	64	62	56	57	52	49	44	42	40	38	35	32	31	30	27	27	582	930
	Battery Storage - S-Oregon	-	-	-	-	45	75	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	120	75
	Battery Storage - Willamette Valley	-	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	45
	Battery Storage - Portland NC	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	120
	Battery Storage - Walla Walla	-	-	-	-	15	30.000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	45
	Battery Storage - Yakima	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	726	715	492	501	622	318	783	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	1,005	1,075	1,072	738	903
	FOT West - Winter	151	131	265	299	310	25	29	224	754	279	52	-	-	-	-	-	-	-	-	-	247	126
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(202)	(730)	(386)	(466)	(502)	(764)	(971)	(1,115)	(1,013)	(114)	(557)	(156)	(36)	(280)	(1,351)	(43)		
	Annual Additions, Long Term Resources	130	151	308	221	354	4,361	160	598	833	943	2,125	3,278	1,630	188	630	86	99	477	532	35		
	Annual Additions, Short Term Resources	877	846	757	800	932	344	812	1,370	2,076	1,589	1,427	1,375	1,375	1,375	1,375	1,375	1,374	1,305	1,375	1,372		
	Total Annual Additions	1,007	997	1,065	1,021	1,286	4,705	972	1,968	2,909	2,532	3,553	4,653	3,005	1,563	2,005	1,461	1,473	1,782	1,907	1,408		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-16	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	CCCT - Utah-N - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	189	-	-	189
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	189	-	-	189
	SCCT Frame UTN	-	-	-	-	195	-	-	-	-	-	-	-	-	-	389	-	-	-	-	-	195	584
	SCCT Frame UTS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	389	-	-	389
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370	370
	Total SCCT	-	-	-	-	195	-	-	-	-	370	-	-	-	-	389	-	-	-	389	-	564	1,342
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	157	436	27	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	85	782	233	-	-	-	-	-	-	-	1,100
	Total Wind	-	-	-	-	-	-	-	-	-	-	157	521	809	233	-	-	-	-	-	-	-	1,720
	Utility Solar - PV - Utah-S	-	-	146	59	-	95	-	-	-	-	-	-	-	-	-	-	-	400	-	-	300	700
	Utility Solar - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	111	-	-	111
	Utility Solar - PV - Naughton	-	-	-	-	73	564	-	-	-	-	-	-	-	-	-	-	-	-	-	-	637	637
	Utility Solar - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	306	-	306
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	603	-	603
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	-	106	22	-	-	-	-	-	-	-	128
	Total Solar	-	-	146	59	73	659	-	-	-	-	-	-	106	22	-	-	-	400	211	909	937	2,585
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	45.8	-	-	-	-	59.8	11.0	-	-	-	-	8.2	8.3	-	-	5.1	105.6	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	55.7	-	8.2	7.2	-	59.8	17.7	-	-	6.8	5.2	8.2	15.3	-	157.1	21.6	150.2	382.2
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	5	4	4	3	3	3	67	113
	Energy Efficiency, UT	58	67	67	69	75	66	65	63	59	57	52	51	48	48	47	34	31	25	22	25	646	1,028
	Energy Efficiency, WY	10	10	13	14	16	14	14	15	17	16	14	14	12	11	11	8	8	7	5	5	138	233
	Energy Efficiency Total	74	83	86	90	98	87	86	84	83	80	73	71	66	65	63	46	42	35	30	33	851	1,374
	Battery Storage - Utah-N	-	-	-	-	90.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(90)	90	-
	Battery Storage - WYSW	-	-	-	-	135.0	-	-	-	-	-	-	-	-	-	-	-	-	-	210.0	270.0	135.0	615.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135.0	-	-	135.0
	FOT East - Summer	-	-	-	-	290	115	209	187	250	284	300	277	198	217	256	256	300	300	300	300	134	202
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	CCCT - Jbridger - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	974	-	974
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	974	-	974
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	-	-	-	-	210	210
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	SCCT Frame YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	233	-	-	233
	Total SCCT	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	-	-	676	-	210	886
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	-	-	120
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	120	-	-	120
	Utility Solar - PV - S-Oregon	-	-	-	-	-	290	-	-	-	-	-	-	-	-	-	-	433	-	-	-	290	723
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	82	-	82
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	-	-	-	-	42
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	77	-	-	77
	Total Solar	-	-	-	-	-	695	-	-	-	-	-	-	-	-	-	-	475	-	77	82	695	1,329
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	-	-	5.5
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.0	-	14.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	2.0	-	55.3	-	9.4	66.7
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	44	43	42	47	34	31	30	33	31	28	26	25	28	25	25	24	25	24	23	375	627
	Energy Efficiency, WA	11	10	11	12	12	11	11	11	11	10	9	9	8	8	7	6	6	5	4	4	109	175
	Energy Efficiency Total	52	56	56	56	61	46	44	43	45	43	39	37	35	37	34	32	32	30	28	27	501	834
	Battery Storage - S-Oregon	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	-	-	-	150	90	135	375
	Battery Storage - Willamette Valley	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	45
	Battery Storage - Portland NC	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	-	-	45	60	45	150
	Battery Storage - Walla Walla	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	60	105	105	270
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	961	621	682	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,013	1,075	1,054	971	1,019
	FOT West - Winter	151	131	269	307	318	268	275	279	331	135	159	160	190	208	225	242	243	404	230	240	246	238
	Existing Plant Retirements/Conversions	-	(308)	(573)	(224)	(709)	(62)	-	(148)	(3)	(764)	(93)	(149)	(350)	(114)	(557)	(156)	(117)	(280)	(2,260)	(1,101)		
	Annual Additions, Long Term Resources	130	139	304	204	1,142	1,488	138	134	128	771	287	629	1,016	364	491	87	566	465	2,532	2,482		
	Annual Additions, Short Term Resources	1,149	1,092	890	989	1,684	1,458	1,559	1,541	1,655	1,495	1,534	1,512	1,463	1,499	1,556	1,572	1,618	1,717	1,605	1,594		
	Total Annual Additions	1,279	1,231	1,194	1,193	2,825	2,946	1,698	1,676	1,783	2,266	1,821	2,141	2,479	1,863	2,047	1,659	2,184	2,182	4,137	4,076		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

		Capacity (MW)																				Resource Totals 1/	
	P-17	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	-	-	-	-	(44)	(44)
	Hayden 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	(33)
	Hunter 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(418)	-	-	-	-	-	-	-	-	-	-	(418)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	(269)
	Hunter 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(471)	-	-	-	-	-	-	-	-	(471)
	Huntington 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)
	Huntington 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Wyodak (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	(268)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret. WY-Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - Utah-N - J 1x1	-	-	-	-	-	-	-	-	-	504	63	-	-	-	-	-	-	-	-	-	504	567
	Total CCCT	-	-	-	-	-	-	-	-	-	504	63	-	-	-	-	-	-	-	-	-	504	567
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	195	-	-	-	-	-	-	-	-	195
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	370
	SCCT Frame UTN	-	-	-	-	195	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195	195
	SCCT Frame UTS	-	-	-	-	-	-	-	-	-	-	389	-	-	-	-	-	-	-	-	-	-	389
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	185	-	185	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	195	-	-	-	-	-	574	370	379	-	-	-	-	-	-	-	195	1,518
	Wind, Dejohnston	-	-	-	-	-	-	-	-	-	16	396	14	-	-	-	-	-	-	-	-	16	425
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	103	-	-	-	-	-	-	-	-	-	103
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	195	-	-	-	-	-	-	-	-	-	195
	Total Wind	-	-	-	-	-	1,920	-	-	-	16	396	311	-	-	-	-	-	-	-	-	1,936	2,643
	Utility Solar - PV - Utah-S	-	-	146	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	146	546
	Utility Solar - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	154	-	-	-	-	111	-	-	-	-	-	-	-	-	-	154	265
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	803	-	-	-	-	-	-	-	-	-	803
	Utility Solar - PV - Naughton	-	-	-	-	111	156	-	-	-	-	-	-	-	-	-	-	-	-	-	-	267	267
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	459	256	-	-	-	-	-	-	-	-	-	715
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	33	-	-	-	-	-	-	-	-	-	-	33
	Utility Solar+Storage - PV - Utah-N	-	-	-	64	-	42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	106	106
	Total Solar	-	-	146	64	111	351	-	-	-	-	603	1,158	-	-	-	-	-	400	-	-	673	2,834
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	-	-	-	-	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	-	-	-	-	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	68.5	-	-	-	5.7	-	-	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	116.7	-	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	-	-	2.1	-	-	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	-	-	-	-	-	1.2	18.7	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	116.7	18.7	6.7	8.2	121.9	13.8	-	-	23.0	3.7	3.2	21.6	179.9	382.2
	Energy Efficiency, ID	6	7	7	7	7	8	7	7	7	7	7	6	6	6	6	4	4	4	3	3	70	118
	Energy Efficiency, UT	58	69	69	69	75	72	71	72	65	62	57	56	52	50	49	38	35	28	20	22	682	1,087
	Energy Efficiency, WY	10	10	11	12	15	16	16	17	18	17	15	15	13	12	11	9	8	7	5	5	143	244
	Energy Efficiency Total	74	85	87	88	97	96	95	97	90	86	79	77	71	68	65	51	47	38	28	30	895	1,449
	Battery Storage - Utah-N	-	-	-	-	-	-	-	225.0	330.0	-	-	-	-	-	-	-	-	-	15	-	555	570
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	-	-	405.0	-	-	420.0
	Battery Storage – WYSW	-	-	-	-	-	-	-	-	-	-	-	30.0	45.0	-	195.0	-	15.0	-	345.0	105.0	-	735.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	-	105.0	270.0	15.0	-	555.0
	FOT East - Summer	-	-	-	-	-	-	-	26	256	269	208	300	300	49	88	88	88	300	55	300	55	116
	FOT East - Winter	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300	300	300	-	300	-	-	75
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	-	-	-	-	-	221
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	-	-	-	-	-	221
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	42	-	-	42
	Utility Solar - PV - jbridger	-	-	-	-	-	-	-	-	66	-	-	-	-	-	-	-	-	-	-	-	66	66
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	349	-	-	51	949	-	-	-	-	-	-	-	-	-	-	1,349	1,349
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	206	248	21	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	388	-	405	793
	Total Solar	-	-	-	-	-	1,254	-	-	117	949	-	206	248	21	100	-	-	-	430	-	2,320	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	-	-	-	-	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	-	-	-	-	-	5.4	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	-	-	-	-	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	-	-	-	-	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	-	3.1	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	14.6	-	-	-	-	-	-	-	-	-	2.0	-	14.6	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	58.4	-	-	-	50.5	-	-	-	-	-	8.2	-	58.4	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	19	34
	Energy Efficiency, OR	40	51	50	49	49	48	45	44	41	37	33	31	30	29	26	26	25	26	22	21	453	721
	Energy Efficiency, WA	11	10	11	12	13	13	12	12	11	10	9	9	8	8	7	6	6	5	4	4	116	183
	Energy Efficiency Total	52	63	63	63	64	63	59	59	54	49	44	42	40	38	35	34	33	32	27	26	588	938
	Battery Storage - S-Oregon	-	-	-	-	-	-	75	90	-	-	-	-	-	-	-	-	-	-	-	-	165	165
	Battery Storage - Willamette Valley	-	-	-	-	-	-	30	45	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Battery Storage - Walla Walla	-	-	-	-	-	-	90	75	-	-	-	-	-	-	-	-	-	-	-	-	165	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	726	715	492	501	617	273	737	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,052	979	1,075	1,073	729	896
	FOT West - Winter	8	131	265	300	311	23	27	141	659	430	227	154	-	344	412	368	333	308	324	419	229	259
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(202)	(730)	(386)	(466)	(502)	(764)	(971)	(1,115)	(1,013)	(114)	(557)	(156)	(36)	(280)	(1,351)	(43)		
	Annual Additions, Long Term Resources	130	148	303	215	485	3,684	357	703	765	1,622	1,765	2,203	1,177	140	575	85	118	579	1,531	197		
	Annual Additions, Short Term Resources	734	846	757	801	928	296	764	1,241	1,989	1,774	1,511	1,529	1,375	1,768	1,875	1,831	1,773	1,587	1,755	1,792		
	Total Annual Additions	864	995	1,060	1,016	1,413	3,979	1,122	1,944	2,755	3,396	3,276	3,731	2,552	1,909	2,450	1,916	1,891	2,166	3,286	1,989		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-18	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	-	-	-	-	(44)	(44)
	Hayden 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	(33)
	Hunter 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(418)	-	-	-	-	-	-	-	-	-	-	(418)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	-	-	-	-	-	-	-	(269)
	Hunter 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(471)	-	-	-	-	-	-	-	-	(471)
	Huntington 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(459)	-	-	-	-	-	-	-	-	-	-	(459)
	Huntington 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	-	-	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Wyodak (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(268)	-	-	-	-	-	-	-	-	(268)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Espire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Espire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	185	-	-	-	-	-	-	-	-	-	185
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	370	185	-	-	-	-	-	-	-	-	-	555
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	620	-	1,100	-	-	-	-	-	-	-	-	2,540	3,640
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	-	400
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	300	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	-	-	300	310
	Utility Solar - PV - Naughton	-	-	-	-	201	156	-	-	-	-	-	-	-	-	-	-	-	-	-	-	357	357
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	459	393	12	45	-	-	-	-	-	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	300	-	-	600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	600	-	201	856	-	-	-	-	469	393	12	45	-	-	-	400	-	-	1,657	2,976
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	-	-	-	-	-	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	5.3	3.0	-	-	-	-	-	-	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	9.2	-	59.3	-	-	-	-	5.7	-	-	2.6	9.2	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	37.3	-	-	-	-	2.1	-	-	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	-	-	-	-	-	1.2	18.7	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	144.5	6.7	118.0	3.0	13.8	-	-	23.0	3.7	3.2	21.6	189.1	382.2
	Energy Efficiency, ID	6	7	7	8	8	8	8	8	8	8	7	7	6	6	6	5	4	4	3	3	76	128
	Energy Efficiency, UT	58	74	75	78	80	85	84	82	72	74	72	60	59	56	54	44	40	32	27	26	762	1,232
	Energy Efficiency, WY	10	14	15	16	18	19	19	19	19	18	16	15	13	12	12	9	9	7	6	6	165	270
	Energy Efficiency Total	74	95	97	102	106	112	111	108	98	100	95	82	79	75	72	59	53	43	35	35	1,003	1,630
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	390.0	-	-	-	-	-	-	-	-	-	-	-	390	390
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	300.0	540.0	-	345.0	15.0	15.0	-	645.0	-	-	1,860.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	45.0	15.0	-	75.0	60.0	255.0	-	75.0	-	-	-	120.0	45.0	60.0	690.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	255.0	135.0	-	-	-	-	-	180.0	15.0	-	585.0
	Geothermal, Greenfield - East	-	-	-	-	-	-	-	-	-	-	490	-	-	-	-	-	-	-	-	-	-	490
	FOT East - Summer	46	46	46	46	46	36	129	-	100	100	44	300	88	256	279	274	300	300	300	300	59	152
	FOT East - Winter	-	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	15
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Espire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Espire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	221	-	-	-	-	-	-	-	-	221	-	221	443
	Total SCCT	-	-	-	-	-	-	-	-	-	221	-	-	-	-	-	-	-	-	221	-	221	443
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	333	-	-	-	-	-	-	-	-	-	333
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	333	-	-	-	-	-	-	-	-	-	333
	Utility Solar - PV - jbridger	-	-	-	-	-	-	353	147	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	349	-	212	354	-	-	-	-	-	-	-	-	-	-	-	915	915
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	975	-	-	-	-	-	-	-	-	-	-	-	-	-	-	975	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	97	-	-	-	-	-	-	-	405	502
	Total Solar	-	-	-	-	-	1,729	353	359	354	-	-	-	97	-	-	-	-	-	-	-	2,795	2,893
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	-	-	-	-	1.1	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	35.7	-	-	-	-	-	-	-	-	-	-	35.7	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	-	-	-	-	-	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	9.9	-	-	-	-	-	-	-	-	-	-	9.9	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	3.1	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	14.6	-	-	-	-	-	-	-	-	2.0	-	14.6	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	99.7	-	7.7	-	-	-	-	-	-	8.2	-	99.7	115.5
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	21	36
	Energy Efficiency, OR	40	53	53	52	49	48	45	43	41	38	35	32	31	30	27	27	26	26	24	24	461	743
	Energy Efficiency, WA	11	12	12	12	13	13	13	12	12	11	10	10	9	8	8	6	6	5	4	4	122	193
	Energy Efficiency Total	52	67	67	66	64	64	60	58	54	52	47	44	42	40	37	35	34	32	29	29	604	972
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	180	-	-	-	-	-	-	-	-	-	-	-	-	180	180
	Battery Storage - Willamette Valley	-	-	-	-	-	15	-	45	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	Battery Storage - Portland NC	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	Battery Storage - Yakima	-	-	-	-	-	60	-	45	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	680	658	654	783	811	467	193	620	969	1,075	1,075	1,064	902	1,075	1,053	1,041	989	918	1,075	1,028	691	857
	FOT West - Winter	224	14	-	-	-	-	-	-	273	100	-	-	-	-	169	499	91	-	-	-	61	68
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(202)	(730)	(386)	(466)	(502)	(764)	(971)	(1,115)	(1,013)	(114)	(557)	(156)	(36)	(280)	(1,351)	(43)		
	Annual Additions, Long Term Resources	130	162	779	168	381	4,755	533	968	912	1,237	1,553	2,877	1,164	173	529	108	125	479	1,242	145		
	Annual Additions, Short Term Resources	950	718	699	829	857	503	322	620	1,342	1,276	1,119	1,364	1,290	1,331	1,501	1,814	1,380	1,218	1,375	1,328		
	Total Annual Additions	1,080	880	1,478	997	1,238	5,258	855	1,588	2,253	2,512	2,671	4,241	2,455	1,504	2,030	1,922	1,505	1,696	2,617	1,474		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-19	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	(238)	-	-	-	-	-	-	-	-	-	-	-	(119)	-	-	-	-	-	(238)	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	CCCT - Utah-N - J 1x1	-	-	-	-	-	-	-	-	-	567	-	-	-	-	-	-	-	-	-	-	567	567
	Total CCCT	-	-	-	-	-	-	-	-	-	567	-	-	-	-	-	-	-	-	-	-	567	567
	SCCT Frame HTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195	-	-	195
	SCCT Frame NTN	-	-	-	-	185	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	185	185
	SCCT Frame UTN	-	-	-	-	195	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195	195
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	379	-	-	-	-	-	-	-	-	-	-	-	-	-	564	-	379	944
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	529	91	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	1,062	-	-	-	-	-	-	-	1,062
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	-	529	91	1,062	-	-	-	-	-	-	1,920	3,602
	Utility Solar - PV - Utah-S	-	-	146	59	-	-	-	-	-	-	-	-	-	95	-	-	325	400	-	-	205	1,026
	Utility Solar - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	175	-	-	-	-	175
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	2	35	-	-	-	-	-	-	-	38
	Utility Solar - PV - Naughton	-	-	-	-	82	370	-	-	-	-	-	-	-	-	-	-	-	-	-	-	452	452
	Utility Solar - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	125	-	-	125
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	589	-	-	589
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	-	-	139	-	-	-	-	-	-	-	139
	Total Solar	-	-	146	59	82	370	-	-	-	-	-	-	2	269	-	100	500	400	714	-	657	2,643
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	79.4	-	-	-	37.3	-	-	-	8.2	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.1	37.3	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	12.9	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	1.2	12.9	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	102.1	-	8.2	7.2	37.3	-	6.7	-	8.2	12.0	-	-	15.3	-	92.5	73.3	174.1	382.2
	Energy Efficiency, ID	6	6	6	7	7	6	7	7	7	6	6	6	6	5	5	4	4	3	3	3	65	110
	Energy Efficiency, UT	58	67	67	68	69	60	60	63	59	53	52	51	48	46	44	32	31	23	20	22	623	991
	Energy Efficiency, WY	10	10	11	14	15	14	14	15	15	14	13	14	12	11	11	8	8	7	5	5	133	226
	Energy Efficiency Total	74	83	85	88	91	80	81	84	81	73	71	71	66	62	60	44	42	33	28	30	820	1,326
	Battery Storage - Utah-N	-	-	-	-	270.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	270	675
	Battery Storage - WYSW	-	-	-	-	210.0	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0	360.0	210.0	600.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135.0	150.0	-	285.0
	FOT East - Summer	-	-	-	-	295	76	176	156	186	213	263	243	300	300	268	271	300	300	300	300	110	197
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	210	-	-	-	-	210	-	-	-	419	-	210	839
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	221	-	443
	SCCT Frame YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	233	-	-	233
	Total SCCT	-	-	-	-	-	-	-	-	-	210	-	-	-	-	210	-	-	-	874	221	210	1,515
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	136	-	-	136
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	172	-	172
	Utility Solar - PV - jbridger	-	-	-	-	713	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	713	761
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	295	-	295
	Total Solar	-	-	-	-	713	-	-	-	-	-	-	-	-	-	-	-	-	-	136	515	713	1,364
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, OR-Irrigate	-	-	-	-	9.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.2	9.2
	Demand Response, WA-Irrigate	-	-	-	-	5.2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	5.2
	Demand Response, WA-Thermostat	-	-	-	-	11.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.3	11.3
	Demand Response Total	-	-	-	-	25.7	-	-	-	9.4	-	-	-	-	-	-	-	-	-	-	-	35.1	35.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	16	30
	Energy Efficiency, OR	40	32	31	30	32	28	26	25	24	23	20	19	19	21	19	19	18	21	22	23	292	493
	Energy Efficiency, WA	11	9	9	10	10	9	9	9	9	8	8	8	8	7	7	5	6	4	4	4	95	156
	Energy Efficiency Total	52	43	42	42	44	39	37	36	35	33	30	29	28	30	28	26	25	26	27	27	402	679
	Battery Storage - S-Oregon	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(15)	15	-
	Battery Storage - Willamette Valley	-	-	-	-	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90	90
	Battery Storage - Portland NC	-	-	-	-	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135	90	225
	Battery Storage - Walla Walla	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	135	165
	Battery Storage - Yakima	-	-	-	-	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90	90
	FOT West - Summer	998	961	826	878	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,014	1,075	1,061	1,011	1,039
	FOT West - Winter	151	132	270	308	323	305	260	269	225	-	-	-	-	-	-	-	-	-	-	-	224	112
	Existing Plant Retirements/Conversions	-	(308)	(810)	(224)	(1,065)	(62)	-	(148)	(3)	(764)	(93)	(149)	(350)	(114)	(320)	(156)	(117)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	126	288	188	2,338	2,408	126	128	162	883	108	628	196	1,436	297	170	583	459	2,601	1,931		
	Annual Additions, Short Term Resources	1,149	1,092	1,096	1,186	1,693	1,456	1,511	1,500	1,486	1,288	1,338	1,318	1,375	1,375	1,343	1,346	1,375	1,314	1,375	1,361		
	Total Annual Additions	1,279	1,219	1,385	1,374	4,031	3,864	1,637	1,627	1,648	2,171	1,446	1,946	1,571	2,811	1,640	1,516	1,958	1,773	3,976	3,293		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-20	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	(238)	-	-	-	-	-	-	-	-	-	-	-	(119)	-	-	-	-	-	(238)	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	185	-	-	185	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	185	555	-	185	-	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	620	-	1,100	-	-	-	-	-	-	-	-	2,540	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	-	95	-	-	-	-	-	-	-	-	-	-	-	400	-	-	300	700
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	500
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	295	-	-	-	-	-	-	-	-	-	-	295
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	605	-	-	-	-	-	-	-	-	-	-	-	-	-	-	605	605
	Total Solar	-	-	146	59	-	801	-	-	-	-	295	-	500	-	-	-	-	400	909	-	1,006	3,109
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	-	157.1	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	7	7	8	7	7	7	7	8	7	6	6	6	6	5	4	4	3	3	71	120
	Energy Efficiency, UT	58	67	67	69	75	72	71	68	68	67	57	56	52	50	50	38	34	28	28	30	683	1,106
	Energy Efficiency, WY	10	12	13	14	16	17	19	19	19	18	16	15	13	12	11	9	8	7	6	5	155	258
	Energy Efficiency Total	74	85	87	90	98	96	97	94	94	93	80	77	72	68	67	51	47	39	37	38	909	1,483
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	360.0	-	-	-	-	-	-	-	-	210	390	360	960
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	30.0	-	-	-	-	-	-	-	-	165.0	195.0	30.0	390.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195.0	90.0	-	285.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	205	300	300	300	172	292	293	300	300	300	300	21	153
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	48	-	-	-	-	-	-	-	48
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	48	-	-	-	-	-	-	-	48
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	280	-	-	-	-	-	-	-	-	500	780
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	282	-	-	-	-	-	-	405	687
	Utility Solar - PV - jbridger	-	-	-	-	354	-	-	-	-	-	359	-	-	-	-	-	-	-	-	122	354	836
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	579	-	579
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	195	-	-	-	-	-	-	-	-	-	195
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Total Solar	-	-	-	-	354	905	-	-	-	-	359	575	-	282	100	-	-	-	-	702	1,259	3,277
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	-	-	-	-	5.3	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	43.9	-	-	5.8	-	-	-	-	87.7	2.0	-	139.3
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	19	34
	Energy Efficiency, OR	40	43	43	49	47	46	43	41	41	38	33	31	31	30	27	27	26	27	25	24	430	710
	Energy Efficiency, WA	11	11	11	12	12	12	12	12	11	11	10	9	9	8	8	6	6	5	4	4	114	184
	Energy Efficiency Total	52	56	55	63	61	60	57	55	54	51	45	42	42	40	37	35	34	34	30	29	563	929
	Battery Storage - S-Oregon	-	-	-	-	225	-	-	-	-	15	-	-	-	-	-	-	-	-	150	135	240	525
	Battery Storage - Willamette Valley	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	150	210
	Battery Storage - Portland NC	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150	30	180
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	45	15	120	180
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	717	600	654	1,028	351	440	427	483	1,075	1,075	1,060	1,075	1,074	1,075	1,075	1,066	1,000	1,075	1,075	677	871
	FOT West - Winter	151	127	261	295	303	228	230	229	276	407	427	364	393	376	357	278	309	267	-	-	251	264
	Existing Plant Retirements/Conversions	-	(61)	(810)	(224)	(352)	(62)	-	(230)	(3)	(912)	(449)	(753)	(350)	(114)	(320)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	141	304	211	1,033	3,782	162	156	148	1,289	1,131	2,357	613	640	204	86	96	472	2,428	1,828		
	Annual Additions, Short Term Resources	1,149	844	860	949	1,331	579	670	656	759	1,688	1,802	1,724	1,768	1,622	1,723	1,645	1,675	1,566	1,375	1,375		
	Total Annual Additions	1,279	985	1,164	1,160	2,363	4,361	832	812	907	2,977	2,933	4,081	2,381	2,263	1,927	1,731	1,771	2,038	3,803	3,203		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-28	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret. WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	370	-	-	185	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	370	-	-	555	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,083	-	-	-	-	-	-	-	-	-	1,083
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,083	-	-	-	-	-	-	-	-	1,920	3,623
	Utility Solar - PV - Utah-S	-	-	146	59	67	28	-	-	-	-	-	-	-	-	-	-	-	400	-	-	300	700
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	500
	Utility Solar+Storage - PV - CO	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	-	-	-	-	-	-	17
	Utility Solar - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	-	-	44
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	865	-	-	865
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	37	-	729	-	-	-	-	-	-	-	-	37	765
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135	135
	Total Solar	-	-	146	59	67	263	-	-	-	37	-	729	517	-	-	-	-	400	909	-	571	3,126
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	124.9	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	6.7	124.9	-	12.0	22.3	-	15.3	-	134.8	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	68	67	68	65	62	54	53	52	50	49	36	32	26	25	26	659	1,063
	Energy Efficiency, WY	10	10	11	14	15	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	149	249
	Energy Efficiency Total	74	83	85	88	91	92	92	94	91	87	76	74	71	68	65	49	45	37	33	35	876	1,428
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	345.0	-	-	-	-	-	-	-	-	15	405	345	765
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	105.0	-	-	-	-	-	-	-	-	-	210.0	105.0	315.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195.0	-	-	195.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	-	74	237	243	300	298	300	300	300	300	300	-	133
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	228	-	-	-	-	-	-	-	-	-	-	-	-	-	-	228	228
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - jbridger	-	-	-	-	-	-	-	-	-	-	354	-	-	-	123	-	-	-	-	48	-	525
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	236	-	-	-	-	654	-	890
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	272	-	-	-	-	-	-	-	-	475	-	-	-	-	-	272	747
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Solar	-	-	-	-	-	905	-	-	-	-	354	-	100	-	834	-	-	-	430	702	905	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	9.4	-	-	51.1	-	-	-	76.9	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	42	39	39	43	41	39	37	33	31	30	29	26	27	26	26	25	24	392	667
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	110	178
	Energy Efficiency Total	52	49	48	55	53	52	56	54	52	49	44	41	40	38	35	34	33	32	30	29	520	878
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	165	-	-	-	-	-	-	-	-	375	-	165	540
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	120	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	30	-	75	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	45	-	120	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	497	136	131	234	279	874	1,075	1,075	1,075	1,075	1,075	1,075	1,074	1,010	1,075	1,075	486	777
	FOT West - Winter	151	131	265	300	311	175	182	303	350	362	354	318	370	316	216	135	152	152	-	-	253	227
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(296)	(85)	(764)	(444)	(753)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	132	286	201	229	3,232	156	155	142	1,208	1,101	2,431	728	118	1,563	83	93	469	2,716	1,402		
	Annual Additions, Short Term Resources	1,149	850	757	801	807	311	313	537	629	1,236	1,503	1,630	1,688	1,691	1,588	1,510	1,527	1,462	1,375	1,375		
	Total Annual Additions	1,279	982	1,043	1,003	1,037	3,543	470	693	771	2,444	2,604	4,061	2,417	1,809	3,151	1,593	1,620	1,931	4,091	2,777		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-30	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	185	-	-	-	-	-	-	-	-	-	185
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	185	-	-	-	185	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	185	185	-	-	185	-	-	-	-	-	-	555
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,100	-	-	-	-	-	-	-	-	1,920	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	-	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	205	605
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	95	-	-	-	-	-	-	500	-	-	-	-	-	-	-	95	595
	Utility Solar - PV - Naughton	-	-	-	-	357	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	357	357
	Utility Solar - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	-	-	10
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	899	-	-	899
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	899	-	-	-	-	-	-	-	-	-	899
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	Total Solar	-	-	146	59	357	196	-	-	-	-	-	899	500	-	-	-	-	400	909	-	758	3,466
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68.5	-	-	-	5.7	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	90.8	-	15.3	-	66.3	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	70	117
	Energy Efficiency, UT	58	67	67	69	75	68	67	68	65	62	54	53	52	50	49	36	32	26	21	25	667	1,065
	Energy Efficiency, WY	10	12	13	14	17	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	154	255
	Energy Efficiency Total	74	85	86	90	99	92	92	94	91	87	76	74	72	68	66	49	45	37	29	33	890	1,437
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	45.0	-	-	-	-	-	-	-	-	615	465	45	1,125
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	525.0	-	-	-	-	-	-	-	-	15.0	15.0	525.0	555.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	360.0	150.0	-	510.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	212	231	290	300	289	298	300	300	300	300	300	21	156
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	405	-	-	-	-	-	-	500	905
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - jbridger	-	-	-	-	-	-	-	-	-	-	354	-	-	-	359	-	-	-	-	48	-	761
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	654	-	654
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	70	-	-	-	-	-	-	-	70
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Solar	-	-	-	-	-	905	-	-	-	-	354	-	100	475	359	-	-	-	430	702	905	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	-	-	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	4.1	-	-	-	9.2	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	-	-	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	-	-	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	18.6	-	-	-	90.8	-	-	-	7.7	-	-	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	19	33
	Energy Efficiency, OR	40	43	43	42	47	39	43	41	39	37	33	31	30	29	26	26	25	25	22	21	412	677
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	11	9	9	8	8	8	6	6	5	4	4	113	179
	Energy Efficiency Total	52	56	56	55	61	52	56	54	52	49	44	42	40	38	35	33	32	30	27	26	543	890
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	120	75	120	315
	Battery Storage - Willamette Valley	-	-	-	-	15	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	90	90
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	45	30	75	150
	Battery Storage - Walla Walla	-	-	-	-	75	-	-	-	-	60	-	-	-	-	-	-	-	-	15	75	135	225
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	804	249	341	316	388	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	1,010	1,075	1,075	588	828
	FOT West - Winter	151	131	265	300	310	239	245	247	294	426	418	382	434	455	-	-	-	32	-	-	261	216
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(358)	(62)	-	(148)	(85)	(912)	(444)	(396)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	141	295	204	730	3,166	156	155	142	1,036	1,421	2,307	711	593	1,269	82	92	467	2,639	1,592		
	Annual Additions, Short Term Resources	1,149	850	757	801	1,114	487	586	562	682	1,713	1,724	1,746	1,809	1,819	1,373	1,375	1,374	1,342	1,375	1,375		
	Total Annual Additions	1,279	991	1,052	1,005	1,844	3,653	743	718	824	2,749	3,145	4,054	2,520	2,412	2,642	1,457	1,467	1,809	4,014	2,967		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-31	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	185	-	-	185	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	185	-	-	555	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,083	-	-	-	-	-	-	-	-	-	1,083
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,083	-	-	-	-	-	-	-	-	1,920	3,623
	Utility Solar - PV - Utah-S	-	-	146	59	67	28	-	-	-	-	-	-	-	-	-	-	-	400	-	-	300	700
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	500	-	-	-	-	-	-	-	-	500
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	17	-	-	-	-	-	-	-	-	17
	Utility Solar - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	797	12	-	809
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	40	37	-	129	-	-	-	-	-	-	-	-	76	205
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	695	-	-	-	-	-	-	-	-	-	-	-	-	-	-	695	695
	Total Solar	-	-	146	59	67	823	-	-	40	37	-	129	517	-	-	-	-	400	897	12	1,171	3,126
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	20.5	-	15.3	-	136.6	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	68	116
	Energy Efficiency, UT	58	67	67	68	69	66	67	68	65	62	54	53	52	50	51	36	32	25	22	26	657	1,059
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	19	18	15	14	13	12	11	9	8	7	5	5	147	248
	Energy Efficiency Total	74	83	85	88	91	89	91	93	91	87	76	74	72	68	68	49	45	36	30	35	872	1,423
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	225.0	-	-	-	-	-	-	-	-	105	435	225	765
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	105.0	-	-	-	-	-	-	-	-	-	165.0	105.0	270.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75.0	-	-	-	135.0	-	-	210.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	25	206	289	300	277	298	300	300	300	300	300	3	145
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	374	-	-	-	-	-	-	-	239	-	-	-	-	-	-	374	614
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - Bridger	-	-	-	-	-	-	-	-	-	-	354	-	-	-	359	-	-	-	-	-	-	713
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	702	-	702
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	126	-	-	-	-	-	-	-	236	-	-	-	-	-	-	126	361
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Solar	-	-	-	-	-	905	-	-	-	-	354	-	-	575	359	-	-	-	430	702	905	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	4.1	-	-	-	9.2	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	18.6	-	-	-	41.8	-	-	-	76.9	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	32
	Energy Efficiency, OR	40	34	37	37	39	39	43	41	39	37	33	31	30	29	27	27	26	26	25	24	384	660
	Energy Efficiency, WA	11	9	10	10	12	12	12	11	11	10	9	9	9	8	8	6	6	5	4	4	108	176
	Energy Efficiency Total	52	45	48	49	53	52	56	54	52	49	44	42	40	38	36	34	33	32	30	29	510	869
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	120	-	-	-	-	90	-	-	-	360	-	120	570
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	150	-	-	-	-	15	-	-	-	-	-	150	165
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	45	-	120	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	154	150	151	203	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	1,010	1,075	1,075	494	781
	FOT West - Winter	151	131	265	300	310	209	215	217	264	396	391	352	361	377	310	226	243	243	-	-	246	248
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(505)	(85)	(912)	(444)	(396)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	128	286	195	229	3,790	155	339	182	998	1,236	1,520	629	693	1,260	83	93	468	2,688	1,399		
	Annual Additions, Short Term Resources	1,149	850	757	801	806	363	365	368	466	1,496	1,672	1,715	1,736	1,729	1,682	1,601	1,618	1,553	1,375	1,375		
	Total Annual Additions	1,279	979	1,043	996	1,036	4,153	520	707	648	2,493	2,908	3,235	2,365	2,422	2,943	1,684	1,711	2,020	4,063	2,774		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-32	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	185	-	-	185	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	185	-	-	185	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	126	494	-	-	-	-	-	-	-	-	-	126	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	984	-	-	-	-	-	-	-	-	-	984
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	126	494	984	-	-	-	-	-	-	-	-	2,046	3,524
	Utility Solar - PV - Utah-S	-	-	146	59	-	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	205	605
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	95	-	-	-	-	-	-	500	-	-	-	-	-	-	-	95	595
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	53	63	-	-	-	-	-	-	-	-	116
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	802	-	-	-	-	-	-	-	-	-	802
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	98	-	-	-	-	-	-	-	-	-	-	-	-	-	-	98	98
	Total Solar	-	-	146	59	-	293	-	-	-	-	-	855	563	-	-	-	-	400	909	-	498	3,225
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.7	-	-	-	2.1	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	18.4	-	15.3	-	138.7	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	70	118
	Energy Efficiency, UT	58	67	67	69	75	68	67	68	65	62	54	53	52	50	49	36	32	26	23	26	667	1,070
	Energy Efficiency, WY	10	12	13	14	18	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	154	256
	Energy Efficiency Total	74	85	86	90	100	92	92	94	91	87	76	74	72	68	66	49	45	37	32	35	891	1,443
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	270.0	-	-	-	-	-	-	-	-	15	480	270	765
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	150.0	-	-	-	-	-	-	-	-	-	240.0	150.0	390.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60.0	-	-	-	150.0	-	-	210.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	300	246	300	300	252	284	286	300	300	300	300	30	158
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	92	-	-	-	-	-	-	-	92
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - jbridger	-	-	-	-	354	-	-	-	-	-	359	-	-	-	-	-	-	-	-	-	354	713
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	343	-	343
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	383	-	-	-	-	-	-	500	883
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Solar	-	-	-	-	354	905	-	-	-	-	359	-	-	475	-	-	-	-	430	343	1,259	2,866
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	5.3	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	40.4	-	-	-	10.7	-	-	-	76.9	-	9.4	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	43	43	42	47	39	43	41	39	37	33	31	30	29	27	26	26	26	24	24	412	686
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	113	180
	Energy Efficiency Total	52	56	55	55	61	52	56	54	52	49	44	42	40	38	36	34	33	32	29	29	543	900
	Battery Storage - S-Oregon	-	-	-	-	60	-	-	-	-	120	-	-	-	-	15	-	-	-	315	45	180	555
	Battery Storage - Willamette Valley	-	-	-	-	30	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	105	105
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	60	-	-	-	-	45	-	-	-	-	45	60	150
	Battery Storage - Walla Walla	-	-	-	-	75	-	-	-	-	-	-	-	-	-	60	-	-	-	15	105	75	255
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	808	99	190	526	584	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,060	996	1,075	1,061	599	832
	FOT West - Winter	151	131	265	300	310	119	123	125	172	303	300	261	270	246	160	97	106	114	-	-	200	178
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(352)	(62)	-	(587)	(3)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	141	295	204	803	3,262	156	340	142	1,063	1,391	2,148	674	593	497	83	93	469	2,553	1,343		
	Annual Additions, Short Term Resources	1,149	850	757	801	1,118	218	313	651	755	1,678	1,621	1,636	1,645	1,573	1,518	1,458	1,466	1,410	1,375	1,361		
	Total Annual Additions	1,279	991	1,052	1,005	1,921	3,480	470	991	898	2,741	3,012	3,783	2,319	2,166	2,015	1,540	1,559	1,879	3,928	2,703		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-33	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret. WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	555	-	-	370	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, OO	-	-	-	-	-	-	-	-	-	-	-	1,096	-	-	-	-	-	-	-	-	-	1,096
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,096	-	-	-	-	-	-	-	-	1,920	3,636
	Utility Solar - PV - Utah-S	-	-	146	59	-	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	205	605
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	95	-	-	-	-	-	-	500	-	-	-	-	-	-	-	95	595
	Utility Solar+Storage - PV - OO	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	205	-	-	-	-	-	-	-	-	-	205
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	695	-	-	-	-	-	-	-	-	-	-	-	-	-	-	695	695
	Total Solar	-	-	146	59	-	890	-	-	-	-	-	205	504	-	-	-	-	400	909	-	1,095	3,113
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	20.5	-	15.3	-	136.6	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	7	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	70	118
	Energy Efficiency, UT	58	67	69	73	75	68	67	68	65	62	54	53	52	50	49	36	32	26	25	26	672	1,076
	Energy Efficiency, WY	10	12	13	15	18	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	155	256
	Energy Efficiency Total	74	85	88	95	100	92	92	94	91	87	76	74	71	68	65	49	45	37	33	35	897	1,450
	Battery Storage - Utah-N	-	-	-	-	45.0	-	-	-	-	75.0	-	-	-	-	-	-	-	-	285	540	120	945
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	345.0	-	-	-	-	-	-	-	-	-	60.0	345.0	405.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	210.0	165.0	-	375.0
	FOT East - Summer	-	-	-	-	58	-	-	-	-	247	182	285	300	262	269	271	300	300	300	300	31	154
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	407	-	-	-	-	-	-	-	165	-	-	-	-	-	-	407	572
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - Jbridger	-	-	-	-	713	-	-	-	-	-	-	-	-	-	-	-	-	-	-	128	713	842
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	215	-	215
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	93	-	-	-	-	-	-	-	310	-	-	-	-	-	-	93	403
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Solar	-	-	-	-	713	905	-	-	-	-	-	-	-	575	-	-	-	-	430	343	1,618	2,966
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	4.1	-	-	-	9.2	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	9.2	-	-	-	41.8	-	-	-	76.9	-	9.4	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	19	34
	Energy Efficiency, OR	40	43	43	49	47	39	43	41	39	37	33	31	30	29	26	26	26	26	25	24	419	693
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	113	181
	Energy Efficiency Total	52	56	56	63	61	52	56	54	52	49	44	42	40	38	35	33	33	32	30	29	551	907
	Battery Storage - S-Oregon	-	-	-	-	105	-	-	-	-	45	-	-	-	-	-	-	-	-	75	45	150	270
	Battery Storage - Willamette Valley	-	-	-	-	90	-	-	-	-	30	-	-	-	-	-	-	-	-	-	15	120	135
	Battery Storage - Portland NC	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135	60	195
	Battery Storage - Walla Walla	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	-	-	-	15	150	120	285
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	726	719	492	501	1,075	372	463	437	510	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,046	981	1,075	1,075	637	850
	FOT West - Winter	151	131	265	300	310	216	221	222	269	401	397	358	367	376	298	215	232	231	-	-	249	248
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(708)	(62)	-	(148)	(85)	(912)	(93)	(753)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	141	297	216	1,417	3,859	156	155	142	757	756	1,980	615	693	533	82	93	469	2,643	1,538		
	Annual Additions, Short Term Resources	877	850	757	801	1,444	588	684	660	779	1,723	1,655	1,718	1,742	1,713	1,642	1,561	1,578	1,513	1,375	1,375		
	Total Annual Additions	1,007	991	1,054	1,016	2,861	4,448	840	815	921	2,480	2,411	3,698	2,358	2,406	2,174	1,643	1,671	1,982	4,018	2,913		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-34	Capacity (MW)																					Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																							
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	(238)	-	-	-	-	-	-	-	-	-	-	-	(119)	-	-	-	-	-	(238)	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																							
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370	370
	Total SCCT	-	-	-	-	-	-	-	-	-	370	-	555	-	-	-	-	-	-	-	-	370	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	345	275	-	-	-	-	-	-	-	-	-	345	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	345	275	1,100	-	-	-	-	-	-	-	-	2,265	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	-	63	-	-	-	-	-	41	-	-	-	-	-	400	-	-	268	709
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	32	-	-	-	-	-	407	52	-	-	-	-	-	-	-	32	491
	Utility Solar - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23	-	-	23
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	886	-	-	886
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	300
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	600	-	-	-	-	-	-	-	-	-	-	-	-	-	-	600	600
	Total Solar	-	-	146	59	-	795	-	-	-	-	-	748	52	-	-	-	-	400	909	-	1,000	3,109
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	1.8	-	15.3	-	155.3	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	69	72	66	66	65	65	62	56	56	52	50	49	36	32	26	25	26	657	1,065
	Energy Efficiency, WY	10	12	13	14	16	16	16	17	18	17	15	15	13	12	11	9	8	7	5	5	149	250
	Energy Efficiency Total	74	85	86	90	95	89	90	88	89	87	77	77	72	68	65	49	45	37	33	35	875	1,432
	Battery Storage - Utah-N	-	-	-	-	135.0	-	-	-	-	45.0	-	-	-	-	-	-	-	-	315	405	180	900
	Battery Storage - WYSW	-	-	-	-	120.0	-	-	-	-	-	-	-	-	-	-	-	-	-	105.0	315.0	120.0	540.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	180.0	-	-	-	-	-	15.0	135.0	-	330.0
	FOT East - Summer	-	-	-	-	290	-	-	-	-	300	300	300	257	162	298	300	300	300	300	300	59	170
West	**Existing Plant Retirements and PPA Termination**																							
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																							
	SCCT Frame WY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	95	-	-	-	-	-	-	500	595
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	19	405	424
	Utility Solar - PV - Jbridger	-	-	-	-	713	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12	713	725
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	331	-	331
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	380	-	-	-	-	-	-	-	380
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	411	-	411
	Total Solar	-	-	-	-	713	905	-	-	-	-	-	-	100	475	-	-	-	-	-	773	1,618	2,966
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	3.1	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	11.3	-	-	-	-	5.3	-	-	-	-	-	11.3	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	49.7	-	-	-	-	10.7	-	-	-	76.9	-	49.7	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	43	43	42	47	39	36	41	39	37	33	31	30	29	26	26	25	26	24	24	405	676
	Energy Efficiency, WA	11	10	11	12	12	12	11	11	11	10	9	9	9	8	8	6	6	5	4	4	111	179
	Energy Efficiency Total	52	55	55	55	61	52	49	54	52	49	44	42	40	38	35	33	32	32	29	29	534	888
	Battery Storage - S-Oregon	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	-	-	-	300	(75)	120	345
	Battery Storage - Willamette Valley	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90	105	195
	Battery Storage - Portland NC	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	60	90	60	210
	Battery Storage - Walla Walla	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	-	-	-	-	165	135	300
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	726	719	607	661	1,075	675	766	740	813	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	1,010	1,075	1,075	786	927
	FOT West - Winter	151	131	265	300	310	239	243	245	291	423	420	381	433	355	275	192	209	209	-	-	260	254
	Existing Plant Retirements/Conversions	-	(61)	(810)	(224)	(708)	(62)	-	(148)	(85)	(912)	(93)	(753)	(350)	(114)	(320)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	140	303	204	1,659	3,761	147	150	141	1,062	403	2,530	444	593	113	82	93	469	2,441	1,983		
	Annual Additions, Short Term Resources	877	850	872	961	1,675	913	1,009	985	1,104	1,798	1,795	1,756	1,765	1,591	1,648	1,567	1,584	1,519	1,375	1,375		
	Total Annual Additions	1,007	990	1,175	1,164	3,334	4,675	1,156	1,134	1,245	2,861	2,198	4,285	2,209	2,184	1,761	1,649	1,676	1,987	3,816	3,358		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-35	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	370	555	-	-	-	-	-	-	-	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	141	479	-	-	-	-	-	-	-	-	-	141	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,017	-	-	-	-	-	-	-	-	-	1,017
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	141	479	1,017	-	-	-	-	-	-	-	-	2,061	3,557
	Utility Solar - PV - Utah-S	-	-	146	59	-	95	-	-	-	-	-	-	-	223	-	-	-	400	-	-	300	923
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	277	-	-	-	-	-	-	-	277
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	74	9	-	-	-	-	-	-	-	-	83
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	-	-	-	-	-	-	221
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	679	-	-	-	-	-	-	-	-	-	-	-	-	-	-	679	679
	Total Solar	-	-	146	59	-	874	-	-	-	-	-	295	9	500	-	-	-	400	909	-	1,079	3,193
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	-	-	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68.5	-	-	-	5.7	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	45.8	-	-	-	-	70.8	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	-	-	2.1	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	64.0	-	8.2	7.2	-	70.8	6.7	8.2	-	12.0	134.2	-	15.3	3.7	19.2	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	7	7	8	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	70	118
	Energy Efficiency, UT	58	67	68	70	75	67	67	68	65	62	56	56	52	50	49	38	34	25	22	22	668	1,071
	Energy Efficiency, WY	10	12	13	14	16	16	16	18	18	17	15	14	13	12	11	9	8	7	5	5	149	248
	Energy Efficiency Total	74	85	88	91	98	91	91	93	90	86	78	76	71	68	65	51	47	35	30	30	887	1,437
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	135.0	-	-	-	-	-	-	-	-	-	135	135	270
	Battery Storage - WYSW	-	-	-	-	105.0	-	-	-	-	210.0	-	-	-	-	-	-	-	-	360.0	30.0	315.0	705.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.0	30.0	-	15.0	645.0	-	-	780.0
	FOT East - Summer	-	-	-	-	17	-	-	-	-	227	169	255	300	239	296	298	300	297	300	300	24	150
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	349	-	-	-	-	-	-	16	-	-	-	-	-	-	-	349	365
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar - PV - jbridger	-	-	-	-	702	-	-	-	-	-	354	-	-	-	-	-	-	-	-	-	702	1,056
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	151	-	-	-	-	-	-	288	171	-	-	-	-	-	-	151	610
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	-	-	-	-	430
	Total Solar	-	-	-	-	702	905	-	-	-	-	354	-	404	171	430	-	-	-	-	-	1,607	2,966
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	-	-	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	-	-	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	-	-	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	14.6	-	-	-	2.0	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	43.6	-	-	-	56.4	-	-	-	6.1	-	9.4	115.5
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	32
	Energy Efficiency, OR	40	43	43	42	47	39	43	41	39	37	33	31	30	29	26	26	26	26	24	21	412	681
	Energy Efficiency, WA	11	11	11	12	12	12	11	11	11	11	9	9	9	8	8	6	6	5	4	4	112	180
	Energy Efficiency Total	52	56	55	55	61	52	56	54	52	49	44	42	40	38	35	33	33	32	29	26	542	893
	Battery Storage - S-Oregon	-	-	-	-	105	-	-	-	-	30	-	-	-	-	-	-	-	-	255	60	135	450
	Battery Storage - Willamette Valley	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	30	75	60	165
	Battery Storage - Walla Walla	-	-	-	-	90	-	-	-	-	-	-	-	-	-	-	-	-	-	60	105	90	255
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	726	719	492	501	1,075	346	436	411	482	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,072	1,006	1,075	1,072	626	847
	FOT West - Winter	151	131	265	299	310	203	206	208	255	387	594	553	566	529	324	244	225	208	-	-	242	283
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(703)	(62)	-	(148)	(85)	(912)	(444)	(753)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	141	297	205	1,405	3,842	155	154	141	792	1,374	1,993	525	788	1,254	113	95	485	2,343	482		
	Annual Additions, Short Term Resources	877	850	757	800	1,402	548	643	619	737	1,689	1,838	1,883	1,941	1,843	1,695	1,616	1,597	1,512	1,375	1,372		
	Total Annual Additions	1,007	991	1,053	1,006	2,807	4,390	798	773	878	2,481	3,212	3,875	2,465	2,631	2,949	1,730	1,692	1,997	3,718	1,854		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-45	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	185	-	-	185	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	185	-	-	185	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	102	518	-	-	-	-	-	-	-	-	-	102	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,079	-	-	-	-	-	-	-	-	-	1,079
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	102	518	1,079	-	-	-	-	-	-	-	-	2,022	3,619
	Utility Solar - PV - Utah-S	-	-	146	59	4	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	209	609
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	91	-	-	-	-	-	-	500	-	-	-	-	-	-	-	91	591
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	-	-	-	-	-	21
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	897	12	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	805	-	-	-	-	-	-	-	-	-	805
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	68	27	-	-	-	-	-	-	-	-	-	-	-	-	-	-	95	95
	Total Solar	-	-	146	59	72	218	-	-	-	-	-	826	500	-	-	-	-	400	897	12	495	3,130
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	20.5	-	15.3	-	136.6	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	67	67	68	65	62	54	55	52	50	51	36	32	26	25	26	658	1,065
	Energy Efficiency, WY	10	10	11	14	15	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	149	250
	Energy Efficiency Total	74	83	85	88	91	91	92	94	91	87	76	76	72	68	68	49	45	37	33	35	875	1,432
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	195.0	-	-	-	-	-	-	-	-	300	315	195	810
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	285.0	-	-	-	-	-	-	-	-	-	120.0	285.0	405.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60.0	-	-	-	135.0	180.0	-	375.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	300	242	300	300	267	298	300	300	300	300	300	30	160
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	116	-	-	-	-	-	-	-	-	116
	Utility Solar - PV - Yakima	-	-	-	-	-	376	-	-	-	-	-	-	-	-	-	-	-	-	7	-	376	383
	Utility Solar - PV - jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	-	354	713
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	702	-	702
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	36	323	-	-	-	-	-	-	500	859
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	29	-	-	-	-	-	-	-	-	-	-	-	-	423	-	29	452
	Total Solar	-	-	-	-	-	1,259	-	-	-	-	359	-	152	423	-	-	-	-	430	702	1,259	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	5.3	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	40.4	-	-	-	10.7	-	-	-	47.4	-	9.4	107.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	32
	Energy Efficiency, OR	40	32	37	42	39	39	43	41	39	37	33	31	30	29	27	27	26	26	24	21	387	660
	Energy Efficiency, WA	11	9	10	11	12	12	12	11	11	10	9	9	9	8	8	6	6	5	4	4	109	176
	Energy Efficiency Total	52	43	48	54	53	52	56	54	52	49	44	42	40	38	36	34	33	32	29	26	513	868
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	150	-	-	-	-	60	-	-	-	30	-	150	240
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	195	-	-	-	-	-	-	-	-	-	-	195	195
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	60	-	-	-	-	60	-	-	-	60	-	60	180
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	95	186	507	580	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	1,010	1,075	1,075	565	817
	FOT West - Winter	151	131	265	300	310	112	116	117	164	296	293	253	325	259	189	98	116	115	-	-	196	181
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	126	286	201	235	3,540	156	340	142	1,354	1,415	2,215	764	541	500	83	93	469	2,540	1,411		
	Annual Additions, Short Term Resources	1,149	850	757	801	806	207	302	625	744	1,671	1,610	1,628	1,700	1,601	1,561	1,473	1,490	1,425	1,375	1,375		
	Total Annual Additions	1,279	977	1,043	1,001	1,041	3,747	459	965	886	3,025	3,024	3,844	2,464	2,143	2,061	1,557	1,583	1,894	3,915	2,786		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-46	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	370	-	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	544	76	-	-	-	-	-	-	-	-	-	544	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	544	76	1,100	-	-	-	-	-	-	-	-	2,464	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	67	28	-	-	-	-	-	-	169	-	-	-	-	400	-	-	300	869
	Utility Solar - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	331	-	-	-	-	-	-	-	-	331
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	202	-	-	-	-	-	-	-	-	-	202
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	698	-	-	-	-	-	-	-	-	-	-	-	-	-	-	698	698
	Total Solar	-	-	146	59	67	726	-	-	-	-	-	202	600	-	-	-	-	400	909	-	998	3,109
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68.5	-	-	-	5.7	-	-	74.1
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	3.4
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	-	-	2.1	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	25.4	8.2	-	12.0	112.8	-	15.3	3.7	21.9	17.3	161.2	377.8
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	5	4	3	3	3	68	117
	Energy Efficiency, UT	58	67	67	68	69	66	67	65	65	62	57	54	52	50	49	38	32	26	25	26	654	1,063
	Energy Efficiency, WY	10	10	11	12	13	16	16	17	17	17	15	14	13	12	11	9	8	7	5	5	139	238
	Energy Efficiency Total	74	83	85	86	89	90	91	88	89	86	79	74	71	67	65	51	45	37	33	35	861	1,417
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	240.0	-	-	-	-	-	-	-	-	-	-	240	240
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	495.0	-	-	495.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	240.0	-	-	-	-	-	-	-	-	135.0	-	240.0	375.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	210.0	60.0	-	285.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	227	241	159	208	135	285	286	300	286	300	300	23	136
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	(49)	-	-	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Utility Solar - PV - Yakima	-	-	-	-	-	289	-	-	-	-	-	-	-	-	-	-	-	-	-	407	289	696
	Utility Solar - PV - jbridger	-	-	-	-	-	-	-	713	-	-	349	-	-	-	251	-	-	-	-	-	713	1,313
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	102	-	-	-	-	-	-	102
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	116	-	-	-	-	-	-	-	-	-	-	-	-	-	23	116	139
	Total Solar	-	-	-	-	-	905	-	713	-	-	349	-	-	575	353	-	-	-	-	430	1,618	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	-	-	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	-	-	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	-	-	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	3.1	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	11.3	3.3	-	-	-	2.0	-	-	-	-	-	11.3	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	49.7	8.7	-	-	-	51.0	-	-	-	6.1	-	49.7	115.5
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	42	39	46	43	41	39	37	33	31	30	30	27	27	26	26	25	24	399	677
	Energy Efficiency, WA	11	9	10	11	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	109	177
	Energy Efficiency Total	52	48	48	54	53	59	56	54	52	49	44	42	40	40	37	34	33	32	30	29	525	887
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	45	-	-	-	-	-	-	-	-	555	30	45	630
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90	-	-	90
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	30	-	120	150
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	30	30	105	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	54	47	538	610	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,061	1,007	1,075	1,075	553	810
	FOT West - Winter	151	131	265	299	310	91	95	96	143	275	482	441	450	432	231	159	176	160	-	-	186	219
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,207)	(85)	(912)	(444)	(396)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	131	286	199	227	3,700	155	1,048	140	1,701	952	1,796	711	694	1,061	85	93	488	2,545	631		
	Annual Additions, Short Term Resources	1,149	850	757	800	806	145	142	634	753	1,577	1,797	1,675	1,733	1,642	1,591	1,520	1,537	1,452	1,375	1,375		
	Total Annual Additions	1,279	982	1,043	999	1,033	3,844	297	1,683	893	3,278	2,749	3,471	2,444	2,336	2,652	1,605	1,630	1,940	3,920	2,006		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-53	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	370	-	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	544	76	-	-	-	-	-	-	-	-	-	544	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	544	76	1,100	-	-	-	-	-	-	-	-	2,464	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	67	28	-	-	-	-	-	-	169	-	-	-	-	400	-	-	300	869
	Utility Solar - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	331	-	-	-	-	-	-	-	-	331
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	202	-	-	-	-	-	-	-	-	-	202
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	698	-	-	-	-	-	-	-	-	-	-	-	-	-	-	698	698
	Total Solar	-	-	146	59	67	726	-	-	-	-	-	202	600	-	-	-	-	400	909	-	998	3,109
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68.5	-	-	-	5.7	-	-	74.1
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	3.4
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	-	-	2.1	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	25.4	8.2	-	12.0	112.8	-	15.3	3.7	21.9	17.3	161.2	377.8
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	5	4	3	3	3	68	117
	Energy Efficiency, UT	58	67	67	68	69	66	67	65	65	62	57	54	52	50	49	38	32	26	25	26	654	1,063
	Energy Efficiency, WY	10	10	11	12	13	16	16	17	17	17	15	14	13	12	11	9	8	7	5	5	139	238
	Energy Efficiency Total	74	83	85	86	89	90	91	88	89	86	79	74	71	67	65	51	45	37	33	35	861	1,417
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	240.0	-	-	-	-	-	-	-	-	495	-	240	735
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	240.0	-	-	-	-	-	-	-	-	135.0	-	240.0	375.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	210.0	60.0	-	285.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	227	241	159	208	135	285	286	300	286	300	300	23	136
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Utility Solar - PV - Yakima	-	-	-	-	-	289	-	-	-	-	-	-	-	-	-	-	-	-	-	407	289	696
	Utility Solar - PV - Jbridger	-	-	-	-	-	-	-	713	-	-	349	-	-	-	251	-	-	-	-	-	713	1,313
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	102	-	-	-	-	-	-	102
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	116	-	-	-	-	-	-	-	-	-	-	-	-	-	23	116	139
	Total Solar	-	-	-	-	-	905	-	713	-	-	349	-	-	575	353	-	-	-	-	430	1,618	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	-	-	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	-	-	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	-	-	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	3.1	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	11.3	3.3	-	-	-	2.0	-	-	-	-	-	11.3	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	49.7	8.7	-	-	-	51.0	-	-	-	6.1	-	49.7	115.5
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	42	39	46	43	41	39	37	33	31	30	30	27	27	26	26	25	24	399	677
	Energy Efficiency, WA	11	9	10	11	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	109	177
	Energy Efficiency Total	52	48	48	54	53	59	56	54	52	49	44	42	40	40	37	34	33	32	30	29	525	887
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	45	-	-	-	-	-	-	-	-	555	30	45	630
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90	-	-	90
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	30	-	120	150
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	30	30	105	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	54	47	538	610	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,061	1,007	1,075	1,075	553	810
	FOT West - Winter	151	131	265	299	310	91	95	96	143	275	482	441	450	432	231	159	176	160	-	-	186	219
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,212)	(85)	(912)	(442)	(396)	(350)	(114)	(911)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	131	286	199	227	3,700	155	1,048	140	1,701	952	1,796	711	694	1,061	85	93	488	2,545	631		
	Annual Additions, Short Term Resources	1,149	850	757	800	806	145	142	634	753	1,577	1,797	1,675	1,733	1,642	1,591	1,520	1,537	1,452	1,375	1,375		
	Total Annual Additions	1,279	982	1,043	999	1,033	3,844	297	1,683	893	3,278	2,749	3,471	2,444	2,336	2,652	1,605	1,630	1,940	3,920	2,006		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-54	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret. WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	185	-	-	185	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	185	-	-	185	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, OO	-	-	-	-	-	-	-	-	-	-	-	1,078	-	-	-	-	-	-	-	-	-	1,078
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,078	-	-	-	-	-	-	-	-	1,920	3,618
	Utility Solar - PV - Utah-S	-	-	146	59	67	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	272	672
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	28	-	-	-	-	-	-	500	-	-	-	-	-	-	-	28	528
	Utility Solar+Storage - PV - CO	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	-	-	22
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	205	-	-	-	-	-	-	-	-	-	205
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	695	-	-	-	-	-	-	-	-	-	-	-	-	-	-	695	695
	Total Solar	-	-	146	59	67	823	-	-	-	-	-	205	522	-	-	-	-	400	909	-	1,095	3,132
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	-	-	-	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	11.7	-	12.0	1.8	-	15.3	-	151.9	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	68	116
	Energy Efficiency, UT	58	67	67	68	69	66	67	65	65	62	55	56	52	52	52	36	32	26	23	22	654	1,060
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	18	18	15	15	13	12	11	9	8	7	5	5	147	248
	Energy Efficiency Total	74	83	85	88	91	89	91	90	90	87	77	77	72	70	70	49	45	37	31	30	868	1,425
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	345.0	-	-	-	-	-	-	-	-	-	375	345	720
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	60.0	-	-	-	-	-	-	-	-	-	165.0	60.0	225.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0	-	-	-	150.0	90.0	-	270.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	295	219	298	300	262	299	300	300	300	300	300	29	159
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	142	-	-	-	-	-	-	500	642
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	7	-	405	412
	Utility Solar - PV - jbridger	-	-	-	-	-	-	359	-	-	-	354	-	-	-	-	-	-	-	-	-	359	713
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	702	-	702
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	333	-	-	-	-	-	-	-	333
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	423
	Total Solar	-	-	-	-	-	905	359	-	-	-	354	-	-	475	100	-	-	-	430	702	1,264	3,325
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	-	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, OR-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	12.0	-	-	17.8
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	1.1	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	5.3	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	35.6	-	10.6	-	11.8	1.5	-	-	86.3	3.0	9.4	158.2
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	36	39	39	43	41	39	37	33	31	30	30	27	26	26	26	25	21	387	660
	Energy Efficiency, WA	11	9	10	10	12	12	12	11	11	11	9	9	9	8	8	6	6	5	4	4	109	177
	Energy Efficiency Total	52	48	48	48	53	52	56	54	52	49	44	42	40	40	37	33	33	32	30	26	513	870
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	120	-	-	-	-	105	-	-	-	420	45	120	690
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	15	15
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	135	-	-	-	-	30	-	-	-	-	45	135	210
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	135	-	-	-	-	15	-	-	-	45	-	135	195
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	180	174	485	558	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	1,009	1,075	1,075	568	818
	FOT West - Winter	151	131	265	300	310	239	243	244	291	423	419	380	389	391	321	231	248	248	-	-	260	261
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	(356)	(505)	(85)	(912)	(444)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	131	286	195	229	3,790	515	336	142	1,177	1,507	1,598	645	597	585	84	93	469	2,696	1,502		
	Annual Additions, Short Term Resources	1,149	850	757	801	806	419	416	729	849	1,792	1,714	1,753	1,764	1,729	1,695	1,606	1,623	1,557	1,375	1,375		
	Total Annual Additions	1,279	982	1,043	995	1,036	4,209	931	1,065	991	2,970	3,220	3,351	2,409	2,326	2,279	1,689	1,716	2,026	4,071	2,877		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.13 - C-Cases, Detailed Capacity Expansion Portfolio

		Capacity (MW)																				Resource Totals 1/	
	P-31C	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	370	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	883	-	-	-	-	-	-	-	-	-	883
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	883	-	-	-	-	-	-	-	-	1,920	3,423
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	300	-	-	-	-	-	-	-	500	-	-	-	-	-	-	300	800
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	149	68	-	-	-	-	-	-	-	-	217
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	73	604	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	73	904	-	-	-	-	-	149	68	500	-	-	-	-	909	-	1,200	2,826
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	54.9	70.0	-	-	-	-	8.3	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	6.7	54.9	70.0	12.0	-	-	7.0	12.0	153.4	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	68	67	68	65	62	62	56	52	52	52	36	33	26	25	26	659	1,079
	Energy Efficiency, WY	10	10	11	14	15	16	17	18	19	18	16	15	13	12	11	9	8	7	5	5	149	252
	Energy Efficiency Total	74	83	85	88	91	92	92	94	91	87	84	77	72	70	70	49	45	37	33	35	876	1,448
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105.0	-	-	-	165	300	-	570
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.0	-	-	-	75.0	165.0	-	330.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195.0	-	-	-	-	150.0	-	345.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	-	46	236	300	230	258	260	300	300	300	300	-	127
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	30
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	30
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	354	-	-	-	359	-	-	-	-	702	-	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	467	-	-	-	-	-	-	33	-	475	-	-	-	-	-	467	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	400	405	805
	Total Solar	-	-	-	-	-	872	-	-	-	-	354	-	33	-	834	-	-	-	-	1,102	872	3,195
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	-	1.9	7.5	-	-	-	-	107.7	-	-	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	39	39	39	43	41	39	37	34	31	30	30	27	26	25	26	24	21	390	662
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	10	10	9	9	8	8	6	6	5	4	4	110	178
	Energy Efficiency Total	52	49	48	52	53	52	56	54	52	49	46	42	40	40	37	33	32	32	29	26	517	873
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	90	-	-	-	90	-	-	-	-	-	-	180
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	45	15	-	-	-	-	-	-	-	-	-	45	60
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	15	-	-	150
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105
	FOT West - Summer	998	719	493	503	498	160	156	157	204	922	1,075	1,075	1,075	1,075	1,075	1,075	1,040	1,044	1,072	1,075	481	775
	FOT West - Winter	151	131	268	303	314	54	61	63	112	244	223	184	200	137	68	-	15	5	-	-	170	127
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(505)	(85)	(912)	(444)	(396)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	132	299	204	235	3,841	156	340	142	181	1,561	1,575	285	629	1,421	82	84	81	2,299	1,829		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	215	217	220	316	1,166	1,344	1,494	1,575	1,442	1,401	1,335	1,355	1,349	1,372	1,375		
	Total Annual Additions	1,279	982	1,060	1,010	1,047	4,055	373	560	458	1,347	2,905	3,069	1,859	2,072	2,822	1,417	1,439	1,430	3,672	3,204		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-36C	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	185	-	-	-	185	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	185	370	-	-	185	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	280	321	20	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,097	-	-	-	-	-	-	-	-	-	1,097
	Wind, UT	-	-	-	-	151	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151	151
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	151	1,920	-	-	-	-	280	1,417	20	-	-	-	-	-	-	-	2,071	3,788
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	149	-	-	-	-	-	-	-	500	-	-	-	-	-	-	149	649
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	3
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	826	-	-	-	-	-	-	3	500	-	-	-	-	909	-	1,049	2,461
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	-	-	74.1
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	46.7	70.0	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	46.7	70.0	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	19.1	161.2	379.6
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	70	118
	Energy Efficiency, UT	58	67	67	68	71	68	71	68	63	59	57	53	50	48	49	36	32	26	25	23	659	1,059
	Energy Efficiency, WY	10	10	11	14	15	16	17	18	17	16	15	14	12	12	11	9	8	7	5	5	144	242
	Energy Efficiency Total	74	83	85	88	94	92	95	93	86	82	79	73	68	65	65	49	45	37	33	31	873	1,418
	Battery Storage - Utah-N	-	-	-	-	-	-	-	15.0	105.0	-	-	-	-	-	-	-	-	-	-	-	120	120
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	750.0	-	-	750.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	30.0	75.0	-	-	-	-	-	-	-	-	-	300.0	60.0	105.0	465.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	435.0	-	-	435.0
	FOT East - Summer	-	-	-	-	-	-	-	77	117	196	195	197	300	197	217	220	225	295	300	300	39	142
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	-	-	-	-	210	210
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	-	-	-	221
	Total SCCT	-	-	-	-	-	-	-	-	-	210	-	-	-	-	221	-	-	-	-	-	210	431
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	932	-	124	-	-	-	-	-	-	-	-	932	1,056
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	116	150	-	-	-	-	-	-	500	765
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	430	-	405	835
	Total Solar	-	-	-	-	-	905	-	-	-	932	-	124	116	150	-	-	-	-	430	-	1,837	2,656
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.8	-	-	26.8
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	3.1	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	11.3	-	-	-	-	-	-	-	-	2.0	-	11.3	13.3
	Demand Response Total	-	-	-	-	-	-	-	-	-	43.9	-	-	-	-	-	-	-	-	35.0	-	43.9	78.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	32
	Energy Efficiency, OR	40	37	43	42	47	46	43	41	39	37	33	31	30	29	26	26	24	25	22	23	413	679
	Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	10	9	9	8	8	7	6	6	5	4	4	111	177
	Energy Efficiency Total	52	49	55	55	61	60	56	55	52	49	44	41	40	38	35	32	31	30	27	27	541	888
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	195	-	-	-	-	-	-	-	-	-	-	-	-	195	195
	Battery Storage - Portland NC	-	-	-	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	150	150
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	-	-	120	120
	Battery Storage - Yakima	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	104	98	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,017	1,075	1,075	663	866
	FOT West - Winter	151	131	265	299	310	34	38	583	630	337	334	261	293	272	-	-	-	-	-	-	278	197
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,914)	(85)	(912)	(93)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	132	305	207	323	3,802	160	955	365	1,387	594	2,034	247	765	508	82	83	67	3,083	138		
	Annual Additions, Short Term Resources	1,149	850	757	800	806	138	136	1,734	1,822	1,608	1,604	1,533	1,668	1,544	1,292	1,295	1,300	1,312	1,375	1,375		
	Total Annual Additions	1,279	982	1,062	1,007	1,129	3,941	296	2,689	2,186	2,994	2,198	3,567	1,914	2,308	1,800	1,376	1,383	1,379	4,458	1,512		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-45C	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	185	-	-	185	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	185	-	-	185	-	-	-	370	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,045	-	-	-	-	-	-	-	-	-	1,045
	Wind, UT	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	18	1,920	-	-	-	-	620	1,045	-	-	-	-	-	-	-	-	1,938	3,603
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	282	-	-	-	-	-	-	500	-	-	-	-	-	-	-	282	782
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38	-	-	-	-	-	-	38
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	55	-	-	-	-	-	-	-	-	-	55
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	899	10	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	54	623	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	54	904	-	-	-	-	-	55	500	-	38	-	-	-	899	10	1,182	2,684
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	-	157.1	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	68	116
	Energy Efficiency, UT	58	65	67	68	69	66	67	65	63	62	57	56	52	50	49	36	32	25	20	22	650	1,049
	Energy Efficiency, WY	10	10	11	12	15	16	16	18	18	18	16	15	13	12	11	9	8	7	5	5	145	246
	Energy Efficiency Total	74	82	85	86	91	89	91	90	88	87	80	77	71	68	66	49	45	35	28	30	863	1,411
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0	-	-	-	225	330	-	585
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	240.0	-	-	-	-	-	-	-	-	90.0	-	330.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	45.0	-	-	135.0	-	-	-	-	180.0	-	360.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	109	225	300	300	252	289	292	300	300	300	300	11	148
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	66	409	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	430	-	-	405	835
	Total Solar	-	-	-	-	-	1,259	-	-	-	-	359	-	66	409	-	-	-	430	-	702	1,259	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	107.7	-	-	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	34	37	36	39	39	43	41	39	37	33	31	30	29	26	26	24	26	22	21	383	650
	Energy Efficiency, WA	11	9	10	11	12	12	12	12	11	10	9	9	8	8	8	6	6	5	4	4	109	175
	Energy Efficiency Total	52	45	48	48	53	52	56	54	52	49	44	42	40	38	35	33	32	32	27	26	509	857
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	75	30	-	-	-	-	-	-	-	-	45	75	150
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	15	75	-	-	-	-	-	-	-	-	-	15	90
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	60	-	-	-	15	-	-	-	-	-	-	75
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	60	-	180
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	90	-	-	-	-	-	-	-	-	-	-	90	90
	FOT West - Summer	998	719	493	503	498	158	153	209	283	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,066	967	1,075	1,075	509	786
	FOT West - Winter	151	131	268	303	314	47	54	58	107	239	232	193	218	156	81	4	17	-	-	-	167	129
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	126	299	198	235	4,225	155	336	140	316	1,761	1,457	677	526	504	82	92	497	2,256	1,494		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	205	207	267	391	1,423	1,532	1,568	1,593	1,483	1,446	1,371	1,384	1,267	1,375	1,375		
	Total Annual Additions	1,279	977	1,060	1,004	1,047	4,430	363	603	531	1,739	3,293	3,024	2,270	2,009	1,949	1,453	1,475	1,765	3,631	2,869		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-46C	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	185	185	-	-	-	-	-	-	-	-	-	185	370
	Total SCCT	-	-	-	-	-	-	-	185	-	185	185	370	-	-	-	-	-	-	-	-	370	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	127	493	-	-	-	-	-	-	-	-	-	127	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,091	-	-	-	-	-	-	-	-	-	1,091
	Wind, UT	-	-	-	-	294	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	294
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	294	1,920	-	-	-	127	493	1,091	-	-	-	-	-	-	-	-	2,341	3,925
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	6	-	-	-	-	-	-	500	-	-	-	-	-	-	-	6	506
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	9
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	683	-	-	-	-	-	-	509	-	100	-	-	-	909	-	906	2,424
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	18.7
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	18.6	161.2	379.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	68	116
	Energy Efficiency, UT	58	61	67	68	69	66	67	65	64	62	57	53	50	48	47	36	32	25	22	22	646	1,037
	Energy Efficiency, WY	10	10	11	12	13	16	16	17	18	17	16	14	12	11	11	9	8	7	5	5	140	238
	Energy Efficiency Total	74	77	85	86	89	89	91	88	88	86	80	73	68	65	63	49	44	35	30	30	854	1,391
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	435	60	-	495
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	105.0	-	-	-	-	-	-	-	-	-	-	105.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	660.0	-	-	660.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	205	239	164	178	235	247	250	267	300	300	300	20	134
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	384	-	-	349	-	-	-	682	-	-	-	-	-	384	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	430	-	405	835
	Total Solar	-	-	-	-	-	905	-	384	-	-	349	-	-	-	1,157	-	-	-	430	-	1,289	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	23.2	-	-	-	22.4	-	-	-	52.8	-	9.4	107.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	32
	Energy Efficiency, OR	40	37	40	42	47	46	43	41	39	37	33	31	30	29	26	26	26	26	24	21	410	680
	Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	10	10	9	8	8	8	6	6	5	4	4	111	178
	Energy Efficiency Total	52	49	52	55	61	59	56	55	52	49	45	41	40	38	35	33	33	32	29	26	539	890
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	15	-	-	150	-	-	-	-	-	-	-	-	60	15	225
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	30	30	-	-	-	-	-	-	-	-	-	-	-	60	60
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	45	-	-	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	15	30	-	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	92	86	578	650	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,063	1,042	1,075	1,075	569	820
	FOT West - Winter	151	131	265	300	310	33	37	38	85	217	254	213	222	170	69	7	16	9	-	-	157	126
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,207)	(85)	(912)	(444)	(396)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	125	303	205	462	3,657	155	869	170	573	1,616	1,584	617	115	1,822	82	85	67	2,769	224		
	Annual Additions, Short Term Resources	1,149	850	757	801	806	125	123	616	735	1,497	1,568	1,452	1,475	1,480	1,391	1,332	1,347	1,351	1,375	1,375		
	Total Annual Additions	1,279	976	1,060	1,005	1,268	3,782	278	1,486	905	2,070	3,184	3,036	2,091	1,594	3,214	1,413	1,431	1,418	4,144	1,599		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-46J23C	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	370	-	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,096	-	-	-	-	-	-	-	-	-	1,096
	Wind, UT	-	-	-	-	294	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	294
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	294	1,920	-	-	-	620	-	1,096	-	-	-	-	-	-	-	-	2,834	3,930
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	6	-	-	-	-	-	-	-	500	-	-	-	-	-	-	6	506
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - CO	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	683	-	-	-	-	-	-	4	500	100	-	-	-	909	-	906	2,419
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	19.8	161.2	380.4
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	5	4	4	3	3	68	118
	Energy Efficiency, UT	58	67	67	68	69	66	67	65	65	62	55	56	52	51	52	39	36	32	26	27	653	1,080
	Energy Efficiency, WY	10	10	11	12	15	16	16	17	18	17	15	14	13	12	11	9	8	7	5	5	143	245
	Energy Efficiency Total	74	83	85	86	91	90	91	88	90	87	77	77	72	69	70	53	48	43	34	35	865	1,442
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420.0	-	-	420.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	30.0	45.0	-	-	-	30.0	-	-	-	300.0	-	30.0	405.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60.0	-	-	-	285.0	45.0	-	390.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	226	239	164	300	203	247	250	267	300	300	300	23	140
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	620	-	-	-	-	349	-	-	-	446	-	-	-	-	-	620	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	345	-	3	127	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	430	-	405	835
	Total Solar	-	-	-	-	-	1,525	-	-	-	-	694	-	3	127	446	-	-	-	430	-	1,525	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	5.3	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	40.4	-	-	-	5.3	-	-	-	52.8	-	9.4	107.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	43	49	47	46	43	43	39	37	33	31	30	29	26	26	24	25	24	21	422	688
	Energy Efficiency, WA	11	10	11	11	12	12	12	12	11	10	9	9	8	8	8	6	6	5	4	4	112	179
	Energy Efficiency Total	52	49	55	62	61	60	57	57	51	49	44	41	40	38	35	32	32	30	29	26	551	899
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	30	-	90	-	-	-	-	-	-	-	-	30	90	120	240
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	15	-	15	30
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	30	60	-	-	-	-	-	-	-	-	-	15	90	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	45	-	-	-	-	-	-	-	-	150	-	45	195
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	90	15	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	259	350	518	589	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,063	1,042	1,075	1,073	600	835
	FOT West - Winter	151	131	265	299	310	33	37	38	85	217	151	150	178	155	69	7	16	9	-	-	157	115
	Existing Plant Retirements/Conversions	-	(61)	(373)	(224)	(1)	(764)	-	(505)	(85)	(912)	(444)	(396)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	132	306	212	464	4,278	156	382	261	1,122	1,277	1,593	118	746	1,190	85	87	73	2,818	231		
	Annual Additions, Short Term Resources	1,149	850	757	800	806	292	387	556	675	1,518	1,465	1,390	1,553	1,432	1,391	1,332	1,347	1,351	1,375	1,373		
	Total Annual Additions	1,279	982	1,063	1,012	1,270	4,570	543	938	936	2,640	2,742	2,982	1,671	2,179	2,582	1,417	1,434	1,425	4,193	1,604		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-47C	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	370	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	968	-	-	-	-	-	-	-	-	-	968
	Wind, UT	-	-	-	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	73
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	73	1,920	-	-	-	-	620	968	-	-	-	-	-	-	-	-	1,993	3,580
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	227	-	-	-	-	-	-	500	-	-	-	-	-	-	-	227	727
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	132	-	-	-	-	-	-	-	-	132
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	904	-	-	-	-	-	-	632	-	100	-	-	-	909	-	1,127	2,769
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	-	-	74.1
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Themostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	6.8	5.2	-	15.3	3.7	153.4	17.3	44.6	377.8
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	68	116
	Energy Efficiency, UT	58	62	67	68	69	66	67	65	65	62	57	56	52	50	52	36	32	26	24	22	648	1,055
	Energy Efficiency, WY	10	10	11	12	15	16	16	18	18	18	16	15	13	12	11	9	8	7	5	5	144	246
	Energy Efficiency Total	74	78	85	86	91	89	91	89	90	87	80	77	72	68	69	49	45	37	32	30	860	1,417
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	465.0	75	-	540.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	165.0	-	-	-	-	-	-	-	135.0	-	-	300.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	-	-	270.0	-	-	285.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	143	261	191	175	226	270	273	300	300	300	300	14	137
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	221	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	221	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	702	-	-	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	460	-	-	-	-	-	-	-	40	475	-	-	-	-	-	460	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	430	-	-	405	835
	Total Solar	-	-	-	-	-	1,219	-	-	-	-	359	-	-	40	475	-	-	1,132	-	-	1,219	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	-	8.3
	Demand Response, WA-Themostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	26.3	81.4	-	-	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	35	37	36	39	39	43	41	39	37	33	31	30	30	27	26	26	26	25	21	384	658
	Energy Efficiency, WA	11	9	10	10	12	12	12	11	11	10	10	9	9	8	8	6	6	5	4	4	108	176
	Energy Efficiency Total	52	46	48	48	53	52	56	54	52	49	45	42	40	40	37	33	33	32	30	26	509	866
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	60	165	-	-	-	-	-	-	-	30	30	60	285
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	15	45	-	-	-	-	-	-	-	-	-	15	60
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	45	-	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	15	-	-	-	105	-	-	-	30	-	-	150
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	170	166	244	318	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,047	1,075	1,045	1,046	518	792
	FOT West - Winter	151	131	268	303	314	58	64	68	118	250	224	185	193	140	71	5	18	-	-	-	173	128
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(982)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	123	299	198	235	4,185	155	336	141	316	1,686	1,464	744	154	806	82	93	1,822	2,357	223		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	228	230	312	436	1,468	1,560	1,451	1,443	1,440	1,417	1,352	1,365	1,375	1,345	1,346		
	Total Annual Additions	1,279	974	1,060	1,004	1,047	4,413	385	648	577	1,784	3,246	2,915	2,187	1,595	2,223	1,434	1,458	3,197	3,702	1,569		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-48C	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	370	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, UT	-	-	-	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	73
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	73	1,920	-	-	-	-	620	1,100	-	-	-	-	-	-	-	-	1,993	3,713
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	227	-	-	-	-	-	195	305	-	-	-	4	-	3	-	227	727
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	904	-	-	-	-	-	195	305	-	100	-	-	-	909	-	1,127	2,636
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	-	-	74.1
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	1.8	15.3	3.7	151.7	19.1	44.6	379.6
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	68	117
	Energy Efficiency, UT	58	67	67	68	69	66	67	65	65	62	57	56	54	52	52	36	32	26	25	26	654	1,070
	Energy Efficiency, WY	10	10	11	12	15	16	16	18	18	18	16	15	13	12	11	9	8	7	5	5	145	248
	Energy Efficiency Total	74	83	85	86	91	89	91	90	90	87	80	77	74	70	70	49	45	37	33	35	866	1,435
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420.0	45	-	465.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	165.0	-	-	-	-	-	-	-	210.0	-	-	375.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	120.0	-	60.0	-	-	-	150.0	-	-	330.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	144	261	300	203	250	299	300	300	300	300	300	14	148
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	-	-	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	-	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	221	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	221	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	519	-	3	174	6	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	462	-	-	-	-	-	-	-	38	475	-	-	-	-	-	462	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	430	-	-	405	835
	Total Solar	-	-	-	-	-	1,221	-	-	-	-	359	-	-	38	475	519	-	433	174	6	1,221	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	3.1	-	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	45.7	-	3.1	58.9	-	-	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	33
	Energy Efficiency, OR	40	37	37	36	39	39	43	41	39	37	34	31	31	29	27	27	24	26	24	24	386	663
	Energy Efficiency, WA	11	9	10	10	12	12	12	11	11	10	10	9	9	8	8	6	6	5	4	4	108	176
	Energy Efficiency Total	52	48	48	48	53	52	56	54	52	49	46	42	42	38	36	34	32	32	29	29	512	871
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	165	-	-	-	45	-	-	-	-	30	-	240
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	75	75
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	90	-	-	-	-	-	-	-	-	-	-	90
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	30	-	-	-	75	-	-	-	-	60	-	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	726	719	493	503	498	170	165	244	318	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	969	1,075	1,073	491	778
	FOT West - Winter	151	131	268	303	314	57	64	68	117	249	224	185	193	140	105	-	-	-	-	-	172	129
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(858)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	131	299	198	235	4,187	155	336	142	316	1,688	1,792	540	159	861	1,241	92	508	2,356	224		
	Annual Additions, Short Term Resources	877	850	761	806	812	227	229	312	436	1,468	1,560	1,560	1,471	1,465	1,478	1,375	1,374	1,269	1,375	1,373		
	Total Annual Additions	1,007	982	1,060	1,004	1,047	4,414	385	648	578	1,784	3,248	3,353	2,012	1,623	2,339	2,616	1,466	1,778	3,731	1,597		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

P-53C	Capacity (MW)																			Resource Totals 1/	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
Existing Plant Retirements and PPA Termination																						
Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
Expansion Resources																						
SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	185	185	-	-	-	-	-	-	-	-	-	185	370
Total SCCT	-	-	-	-	-	-	-	185	-	185	185	370	-	-	-	-	-	-	-	-	370	925
Wind, Djohnston	-	-	-	-	-	-	-	-	-	127	493	-	-	-	-	-	-	-	-	-	127	620
Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,091	-	-	-	-	-	-	-	-	-	1,091
Wind, UT	-	-	-	-	294	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	294
Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
Total Wind	-	-	-	-	294	1,920	-	-	-	127	493	1,091	-	-	-	-	-	-	-	-	2,341	3,925
Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	6	-	-	-	-	-	-	500	-	-	-	-	-	-	-	6	506
Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	9
Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
Total Solar	-	-	159	64	-	683	-	-	-	-	-	-	509	-	100	-	-	-	909	-	906	2,424
Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	18.7
Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	18.6	161.2	379.2
Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	68	116
Energy Efficiency, UT	58	61	67	68	69	66	67	65	64	62	57	53	50	48	47	36	32	25	22	22	646	1,037
Energy Efficiency, WY	10	10	11	12	13	16	16	17	18	17	16	14	12	11	11	9	8	7	5	5	140	238
Energy Efficiency Total	74	77	85	86	89	89	91	88	88	86	80	73	68	65	63	49	44	35	30	30	854	1,391
Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	435	60	-	495
Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	105.0	-	-	-	-	-	-	-	-	-	-	105.0
Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	660.0	-	-	660.0
FOT East - Summer	-	-	-	-	-	-	-	-	-	205	239	164	178	235	247	250	267	300	300	300	20	134
Existing Plant Retirements and PPA Termination																						
JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	(349)
JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	(353)
Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
Expansion Resources																						
SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	384	-	-	349	-	-	-	682	-	-	-	-	-	384	1,415
Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	430	-	405	835
Total Solar	-	-	-	-	-	905	-	384	-	-	349	-	-	-	1,157	-	-	-	430	-	1,289	3,225
Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	23.2	-	-	-	22.4	-	-	-	52.8	-	9.4	107.9
Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	32
Energy Efficiency, OR	40	37	40	42	47	46	43	41	39	37	33	31	30	29	26	26	26	26	24	21	410	680
Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	10	10	9	8	8	8	6	6	5	4	4	111	178
Energy Efficiency Total	52	49	52	55	61	59	56	55	52	49	45	41	40	38	35	33	33	32	29	26	539	890
Battery Storage - S-Oregon	-	-	-	-	-	-	-	15	-	-	150	-	-	-	-	-	-	-	-	60	15	225
Battery Storage - Willamette Valley	-	-	-	-	-	-	-	30	30	-	-	-	-	-	-	-	-	-	-	-	60	60
Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	45	-	-	105
Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	15	30	-	165
Battery Storage - Yakima	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	105	105
FOT West - Summer	998	719	492	501	496	92	86	578	650	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,063	1,042	1,075	1,075	569	820
FOT West - Winter	151	131	265	300	310	33	37	38	85	217	254	213	222	170	69	7	16	9	-	-	157	126
Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,212)	(85)	(912)	(442)	(396)	(350)	(114)	(911)	(156)	(36)	(280)	(2,260)	(43)		
Annual Additions, Long Term Resources	130	125	303	205	462	3,657	155	869	170	573	1,616	1,584	617	115	1,822	82	85	67	2,769	224		
Annual Additions, Short Term Resources	1,149	850	757	801	806	125	123	616	735	1,497	1,568	1,452	1,475	1,479	1,391	1,332	1,347	1,351	1,375	1,375		
Total Annual Additions	1,279	976	1,060	1,005	1,268	3,782	278	1,486	905	2,070	3,184	3,036	2,091	1,594	3,214	1,413	1,431	1,418	4,144	1,599		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

P-53J23C	Capacity (MW)																				Resource Totals 1/	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
Existing Plant Retirements and PPA Termination																						
Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
Expansion Resources																						
SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
Total SCCT	-	-	-	-	-	-	-	185	-	-	370	370	-	-	-	-	-	-	-	-	185	925
Wind, Djohnston	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620	620
Wind, CO	-	-	-	-	-	-	-	-	-	-	-	1,096	-	-	-	-	-	-	-	-	-	1,096
Wind, UT	-	-	-	-	294	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	294
Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
Total Wind	-	-	-	-	294	1,920	-	-	-	620	-	1,096	-	-	-	-	-	-	-	-	2,834	3,930
Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	6	-	-	-	-	-	-	-	500	-	-	-	-	-	-	6	506
Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
Utility Solar+Storage - PV - CO	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
Total Solar	-	-	159	64	-	683	-	-	-	-	-	-	4	500	100	-	-	-	909	-	906	2,419
Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	19.8	161.2	380.4
Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	5	4	4	3	3	68	118
Energy Efficiency, UT	58	67	67	68	69	66	67	65	65	62	55	56	52	51	52	39	36	32	26	27	653	1,080
Energy Efficiency, WY	10	10	11	12	15	16	16	17	18	17	15	14	13	12	11	9	8	7	5	5	143	245
Energy Efficiency Total	74	83	85	86	91	90	91	88	90	87	77	77	72	69	70	53	48	43	34	35	865	1,442
Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420.0	-	-	420.0
Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	30.0	45.0	-	-	-	30.0	-	-	-	300.0	-	30.0	405.0
Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60.0	-	-	-	285.0	45.0	-	390.0
FOT East - Summer	-	-	-	-	-	-	-	-	-	226	239	164	300	203	247	250	267	300	300	300	23	140
Existing Plant Retirements and PPA Termination																						
JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	(349)
JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	(353)
Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
Expansion Resources																						
SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	-	-	443
Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	620	-	-	-	-	349	-	-	-	446	-	-	-	-	-	620	1,415
Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	345	-	3	127	-	-	-	-	-	-	500	975
Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	430	-	405	835
Total Solar	-	-	-	-	-	1,525	-	-	-	-	694	-	3	127	446	-	-	-	430	-	1,525	3,225
Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	5.3	-	-	-	-	-	-	16.6
Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	40.4	-	-	-	5.3	-	-	-	52.8	-	9.4	107.9
Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
Energy Efficiency, OR	40	37	43	49	47	46	43	43	39	37	33	31	30	29	26	26	24	25	24	21	422	688
Energy Efficiency, WA	11	10	11	11	12	12	12	12	11	10	9	9	8	8	8	6	6	5	4	4	112	179
Energy Efficiency Total	52	49	55	62	61	60	57	57	51	49	44	41	40	38	35	32	32	30	29	26	551	899
Battery Storage - S-Oregon	-	-	-	-	-	-	-	30	-	90	-	-	-	-	-	-	-	-	30	90	120	240
Battery Storage - Willamette Valley	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	15	-	15	30
Battery Storage - Portland NC	-	-	-	-	-	-	-	-	30	60	-	-	-	-	-	-	-	-	-	15	90	105
Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	45	-	-	-	-	-	-	-	-	150	-	45	195
Battery Storage - Yakima	-	-	-	-	-	-	-	-	90	15	-	-	-	-	-	-	-	-	-	-	105	105
FOT West - Summer	998	719	492	501	496	259	350	518	589	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,063	1,042	1,075	1,073	600	835
FOT West - Winter	151	131	265	299	310	33	37	38	85	217	151	150	178	155	69	7	16	9	-	-	157	115
Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(768)	-	(505)	(85)	(912)	(442)	(396)	(350)	(114)	(911)	(156)	(36)	(280)	(2,260)	(43)		
Annual Additions, Long Term Resources	130	132	306	212	464	4,278	156	382	261	1,122	1,277	1,593	118	746	1,190	85	87	73	2,818	231		
Annual Additions, Short Term Resources	1,149	850	757	800	806	292	387	556	675	1,518	1,465	1,390	1,553	1,432	1,391	1,332	1,347	1,351	1,375	1,373		
Total Annual Additions	1,279	982	1,063	1,012	1,270	4,570	543	938	936	2,640	2,742	2,982	1,671	2,179	2,582	1,417	1,434	1,425	4,193	1,604		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-54C	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	370	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	823	-	-	-	-	-	-	-	-	-	823
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	823	-	-	-	-	-	-	-	-	1,920	3,363
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	300	-	-	-	-	-	-	500	-	-	-	-	-	-	-	300	800
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	175	102	-	-	-	-	-	-	-	-	277
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	899	10	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	73	604	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	73	904	-	-	-	-	-	175	602	100	-	-	-	-	899	10	1,200	2,986
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	6.8	5.2	-	15.3	3.7	153.4	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	68	117
	Energy Efficiency, UT	58	67	67	68	69	66	67	65	65	62	58	56	52	50	51	36	32	26	25	26	654	1,066
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	18	18	16	15	13	12	11	9	8	7	5	5	147	249
	Energy Efficiency Total	74	83	85	88	91	89	91	90	90	87	80	77	72	68	69	49	45	37	33	35	868	1,432
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	-	90.0	-	-	-	-	-	-	-	-	450	-	540
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	90.0	-	-	-	-	-	-	-	-	165.0	-	255.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135.0	-	-	-	45.0	15.0	-	195.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	133	245	300	290	300	226	228	300	300	300	300	13	146
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	214	-	-	214
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	214	-	-	214
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	359	-	-	-	354	-	-	-	-	-	-	-	-	702	359	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	467	-	-	-	-	-	-	-	33	475	-	-	-	-	-	467	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	216	-	405	621
	Total Solar	-	-	-	-	-	872	359	-	-	-	354	-	-	33	475	-	-	-	216	702	1,231	3,011
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	107.7	-	-	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	37	39	39	43	41	39	37	34	31	30	30	27	26	26	26	25	24	388	666
	Energy Efficiency, WA	11	9	10	11	12	12	12	11	11	11	10	9	9	8	8	6	6	5	4	4	109	178
	Energy Efficiency Total	52	48	48	49	53	52	56	54	52	49	46	42	40	40	37	33	33	32	30	29	514	876
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	60	30	-	-	-	105	-	-	-	135	60	60	390
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	75
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	60	-	-	-	15	-	-	-	15	-	-	90
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	15	75	-	-	-	30	-	-	-	45	15	15	180
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	190	186	234	308	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,002	1,012	1,061	1,075	520	790
	FOT West - Winter	151	131	268	303	314	60	66	68	118	250	228	189	197	142	74	7	20	11	-	-	173	130
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	(356)	(505)	(85)	(912)	(444)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	131	299	201	235	3,838	515	336	142	316	1,653	1,495	714	248	870	82	93	73	2,705	1,502		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	250	252	303	426	1,457	1,548	1,564	1,563	1,517	1,374	1,310	1,322	1,323	1,361	1,375		
	Total Annual Additions	1,279	982	1,060	1,007	1,047	4,088	767	639	568	1,773	3,202	3,059	2,277	1,765	2,244	1,393	1,415	1,395	4,067	2,877		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.14 – CP-Cases, Detailed Capacity Expansion Portfolio

		Capacity (MW)																				Resource Totals 1/	
	P-36CP	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret. WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	185	-	185	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	185	370	185	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	280	321	20	-	-	-	-	-	-	-	-	620
	Wind, CO	-	-	-	-	-	-	-	-	-	-	-	1,097	-	-	-	-	-	-	-	-	-	1,097
	Wind, UT	-	-	-	-	151	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	151	151
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	151	1,920	-	-	-	-	280	1,417	20	-	-	-	-	-	-	-	2,071	3,788
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	149	-	-	-	-	-	-	-	500	-	-	-	-	-	-	149	649
	Utility Solar+Storage - PV - CO	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	3
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	826	-	-	-	-	-	-	3	500	-	-	-	-	909	-	1,049	2,461
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	-	-	74.1
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	46.7	70.0	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	46.7	70.0	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	19.1	161.2	379.6
	Energy Efficiency, ID	6	6	6	7	7	8	7	7	7	7	7	6	6	6	6	5	4	3	3	3	70	118
	Energy Efficiency, UT	58	67	67	69	71	71	71	68	63	62	57	53	52	50	49	37	34	25	22	23	668	1,069
	Energy Efficiency, WY	10	10	11	14	15	16	17	18	17	17	16	14	13	12	11	9	8	7	5	5	146	246
	Energy Efficiency Total	74	83	85	90	94	95	96	94	87	86	80	73	71	67	65	50	47	35	30	32	883	1,433
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	180.0	-	-	-	-	-	-	-	-	-	-	-	180	180
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	210.0	450	-	660.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	105.0	-	-	-	-	-	-	-	-	-	-	255.0	150.0	105.0	510.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	60.0	-	-	-	135.0	-	180.0	30.0	-	405.0
	FOT East - Summer	-	-	-	-	-	-	-	77	117	196	195	197	300	197	217	220	225	295	300	300	39	142
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	-	-	-	-	210	210
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	221	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	221	-	221	-	210	653
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	932	-	124	-	-	-	-	-	-	-	-	932	1,056
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	116	150	-	-	-	-	-	-	500	765
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	430	-	405	835
	Total Solar	-	-	-	-	-	905	-	-	-	932	-	124	116	150	-	-	-	-	430	-	1,837	2,656
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.8	-	-	26.8
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	3.1	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	11.3	-	-	-	-	-	-	-	-	2.0	-	11.3	13.3
	Demand Response Total	-	-	-	-	-	-	-	-	-	43.9	-	-	-	-	-	-	-	-	35.0	-	43.9	78.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	43	43	49	47	46	45	43	39	37	33	31	30	29	26	26	26	25	22	23	430	698
	Energy Efficiency, WA	11	10	11	12	12	13	12	12	11	10	9	9	8	8	8	6	6	5	4	4	113	180
	Energy Efficiency Total	52	55	55	62	61	60	59	57	52	49	44	41	40	38	35	33	33	30	27	27	562	911
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	150	150
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	Battery Storage - Portland NC	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	60	60
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	-	-	120	120
	Battery Storage - Yakima	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	104	98	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,017	1,075	1,075	663	866
	FOT West - Winter	151	131	265	299	310	34	38	583	630	337	334	261	293	272	-	-	-	-	-	-	278	197
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,914)	(85)	(912)	(93)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	138	306	216	323	3,806	163	943	365	1,391	595	2,034	494	767	102	83	443	65	2,461	708		
	Annual Additions, Short Term Resources	1,149	850	757	800	806	138	136	1,734	1,822	1,608	1,604	1,533	1,668	1,544	1,292	1,295	1,300	1,312	1,375	1,375		
	Total Annual Additions	1,279	989	1,063	1,017	1,130	3,945	299	2,677	2,187	2,999	2,199	3,567	2,162	2,311	1,394	1,378	1,743	1,377	3,836	2,083		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-45CP	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	370	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,045	-	-	-	-	-	-	-	-	-	1,045
	Wind, UT	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	18	1,920	-	-	-	-	620	1,045	-	-	-	-	-	-	-	-	1,938	3,603
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	282	-	-	-	-	-	-	500	-	-	-	-	-	-	-	282	782
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38	-	-	-	-	-	-	38
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	55	-	-	-	-	-	-	-	-	-	55
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	899	10	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	54	623	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	54	904	-	-	-	-	-	55	500	-	38	-	-	-	899	10	1,182	2,684
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	-	157.1	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	68	117
	Energy Efficiency, UT	58	67	67	68	69	66	67	65	65	62	57	56	52	52	49	36	34	25	22	26	654	1,062
	Energy Efficiency, WY	10	10	11	12	15	16	16	18	18	18	16	14	13	12	11	9	8	7	5	5	144	246
	Energy Efficiency Total	74	83	85	86	91	90	91	90	90	87	80	77	72	70	65	49	46	35	30	35	866	1,425
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	120.0	-	-	-	-	-	-	-	165.0	240	-	525.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	15.0	-	-	-	-	-	-	-	120.0	225.0	-	360.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	-	-	-	150.0	225.0	-	390.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	109	225	300	300	252	289	292	300	300	300	300	11	148
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	66	409	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	430	-	-	405	835
	Total Solar	-	-	-	-	-	1,259	-	-	-	-	359	-	66	409	-	-	-	430	-	702	1,259	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	107.7	-	-	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	36	39	39	43	41	39	37	34	31	31	30	26	26	24	25	22	21	387	656
	Energy Efficiency, WA	11	9	10	11	12	12	12	11	11	11	10	9	9	8	7	6	6	5	4	4	109	176
	Energy Efficiency Total	52	48	48	48	53	52	56	54	52	49	46	42	41	40	35	33	32	30	27	26	513	864
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	75	105	-	-	-	-	-	-	-	-	-	75	180
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	150	-	-	-	-	-	45	-	-	-	-	195
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	90	-	-	-	-	120
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	158	153	209	283	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,066	967	1,075	1,075	509	786
	FOT West - Winter	151	131	268	303	314	47	54	58	107	239	232	193	218	156	81	4	17	-	-	-	167	129
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	131	299	198	235	4,226	155	336	141	316	1,658	1,597	679	546	138	82	228	495	2,468	1,484		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	205	207	267	391	1,423	1,532	1,568	1,593	1,483	1,446	1,371	1,384	1,267	1,375	1,375		
	Total Annual Additions	1,279	982	1,060	1,004	1,047	4,431	362	603	532	1,739	3,190	3,164	2,272	2,028	1,584	1,453	1,612	1,763	3,843	2,859		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

P-46CP	Capacity (MW)																				Resource Totals 1/	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
Existing Plant Retirements and PPA Termination																						
Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
Expansion Resources																						
SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	185	185	-	-	-	-	-	-	-	-	-	185	370
Total SCCT	-	-	-	-	-	-	-	185	-	185	185	370	-	-	-	-	-	-	-	-	370	925
Wind, Djohnston	-	-	-	-	-	-	-	-	-	127	493	-	-	-	-	-	-	-	-	-	127	620
Wind, CO	-	-	-	-	-	-	-	-	-	-	-	1,091	-	-	-	-	-	-	-	-	-	1,091
Wind, UT	-	-	-	-	294	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	294
Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
Total Wind	-	-	-	-	294	1,920	-	-	-	127	493	1,091	-	-	-	-	-	-	-	-	2,341	3,925
Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	6	-	-	-	-	-	-	500	-	-	-	-	-	-	-	6	506
Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
Utility Solar+Storage - PV - CO	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	9
Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
Total Solar	-	-	159	64	-	683	-	-	-	-	-	-	509	-	100	-	-	-	909	-	906	2,424
Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	18.7
Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	18.6	161.2	379.2
Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	68	116
Energy Efficiency, UT	58	61	67	68	69	66	67	65	65	62	57	56	52	50	49	36	36	25	20	22	647	1,049
Energy Efficiency, WY	10	10	11	12	13	16	16	17	17	17	16	14	13	12	11	9	8	7	5	5	139	238
Energy Efficiency Total	74	77	85	86	89	90	91	88	89	86	79	76	71	67	65	49	48	35	28	30	855	1,403
Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	360.0	135	-	495.0
Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	210.0	-	180.0	-	-	390.0
Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	195.0	-	-	15.0	-	105.0	45.0	-	360.0
FOT East - Summer	-	-	-	-	-	-	-	-	-	205	239	164	178	235	247	250	267	300	300	300	20	134
Existing Plant Retirements and PPA Termination																						
JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
Expansion Resources																						
SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	221	-	-	443
Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	221	-	-	443
Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	384	-	-	349	-	-	-	682	-	-	-	-	-	384	1,415
Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	430	-	405	835
Total Solar	-	-	-	-	-	905	-	384	-	-	349	-	-	-	1,157	-	-	-	430	-	1,289	3,225
Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	23.2	-	-	-	22.4	-	-	-	52.8	-	9.4	107.9
Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
Energy Efficiency, OR	40	37	40	42	47	46	43	41	39	37	33	31	30	30	26	26	26	25	22	21	410	678
Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	10	10	9	9	8	8	6	6	5	4	4	111	178
Energy Efficiency Total	52	48	52	55	61	59	56	55	52	49	45	42	40	40	35	33	33	30	27	26	539	889
Battery Storage - S-Oregon	-	-	-	-	-	-	-	30	-	-	210	-	-	-	-	-	15	-	-	-	30	255
Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	75
Battery Storage - Portland NC	-	-	-	-	-	-	-	30	-	-	30	-	-	-	-	-	30	-	-	-	30	90
Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	30	-	105	-	-	-	-	-	-	-	15	-	30	150
Battery Storage - Yakima	-	-	-	-	-	-	-	90	-	-	15	-	-	-	-	-	-	-	-	-	90	105
FOT West - Summer	998	719	492	501	496	92	86	578	650	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,063	1,042	1,075	1,075	569	820
FOT West - Winter	151	131	265	300	310	33	37	38	85	217	254	213	222	170	69	7	16	9	-	-	157	126
Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,207)	(85)	(912)	(444)	(396)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(43)		
Annual Additions, Long Term Resources	130	125	303	205	462	3,657	155	869	170	573	1,616	1,587	620	314	1,382	82	580	65	2,492	254		
Annual Additions, Short Term Resources	1,149	850	757	801	806	125	123	616	735	1,497	1,568	1,452	1,475	1,480	1,391	1,332	1,347	1,351	1,375	1,375		
Total Annual Additions	1,279	976	1,060	1,005	1,268	3,782	278	1,486	905	2,070	3,184	3,039	2,094	1,794	2,773	1,414	1,926	1,416	3,867	1,629		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-46J23CP	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	370	-	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,096	-	-	-	-	-	-	-	-	-	1,096
	Wind, UT	-	-	-	-	294	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	294
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	294	1,920	-	-	-	620	-	1,096	-	-	-	-	-	-	-	-	2,834	3,930
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	6	-	-	-	-	-	-	-	500	-	-	-	-	-	-	6	506
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	683	-	-	-	-	-	-	4	500	100	-	-	-	909	-	906	2,419
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	19.8	161.2	380.4
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	5	4	3	3	3	69	118
	Energy Efficiency, UT	58	67	67	68	69	68	67	68	65	62	57	56	54	52	51	38	36	26	22	26	659	1,076
	Energy Efficiency, WY	10	10	11	12	14	16	16	17	18	17	16	15	13	12	11	9	8	7	5	5	141	243
	Energy Efficiency Total	74	83	85	86	90	92	91	92	90	86	80	77	73	70	67	51	48	37	30	35	869	1,437
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	360.0	120	-	480.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	120.0	-	-	240.0	-	375.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	75.0	120.0	-	-	45.0	-	-	135.0	-	375.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	226	239	164	300	203	247	250	267	300	300	300	23	140
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	620	-	-	-	-	349	-	-	-	446	-	-	-	-	-	620	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	345	-	3	127	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	430	-	405	835
	Total Solar	-	-	-	-	-	1,525	-	-	-	-	694	-	3	127	446	-	-	-	430	-	1,525	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	5.3	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	40.4	-	-	-	5.3	-	-	-	52.8	-	9.4	107.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	43	49	47	46	43	43	41	38	35	32	31	30	27	27	26	26	24	24	425	707
	Energy Efficiency, WA	11	10	11	11	12	12	12	12	11	11	10	9	9	8	8	6	6	5	4	4	113	182
	Energy Efficiency Total	52	49	55	62	61	60	57	57	54	51	46	44	42	40	36	34	33	32	29	29	556	923
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	15	105	-	-	-	-	-	-	-	-	135	-	120	255
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	-	45	45
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	45	-	-	15	-	-	-	-	-	45	-	45	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	90	30	-	15	-	-	-	-	-	-	-	90	135
	Battery Storage - Yakima	-	-	-	-	-	-	-	45	60	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	259	350	518	589	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,063	1,042	1,075	1,073	600	835
	FOT West - Winter	151	131	265	299	310	33	37	38	85	217	151	150	178	155	69	7	16	9	-	-	157	115
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(764)	-	(505)	(85)	(912)	(444)	(396)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	132	306	212	463	4,279	156	386	263	1,123	1,267	1,595	227	869	672	85	697	69	2,154	578		
	Annual Additions, Short Term Resources	1,149	850	757	800	806	292	387	556	675	1,518	1,465	1,390	1,553	1,432	1,391	1,332	1,347	1,351	1,375	1,373		
	Total Annual Additions	1,279	982	1,063	1,012	1,269	4,572	543	942	938	2,641	2,732	2,985	1,780	2,302	2,063	1,417	2,043	1,420	3,529	1,952		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-47C	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	370	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	968	-	-	-	-	-	-	-	-	-	968
	Wind, UT	-	-	-	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	73
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	73	1,920	-	-	-	-	620	968	-	-	-	-	-	-	-	-	1,993	3,580
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	227	-	-	-	-	-	-	500	-	-	-	-	-	-	-	227	727
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	132	-	-	-	-	-	-	-	-	132
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	904	-	-	-	-	-	-	632	-	100	-	-	-	909	-	1,127	2,769
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	-	-	74.1
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	6.8	5.2	-	15.3	3.7	153.4	17.3	44.6	377.8
	Energy Efficiency, ID	6	5	5	7	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	66	114
	Energy Efficiency, UT	58	61	62	68	69	66	65	65	62	62	57	53	52	50	49	36	32	26	22	26	637	1,040
	Energy Efficiency, WY	10	10	11	12	13	16	16	17	17	17	16	14	13	12	11	9	8	7	5	5	139	239
	Energy Efficiency Total	74	76	78	86	89	89	89	88	85	86	79	74	71	68	65	49	45	36	30	35	841	1,393
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	435.0	105	-	540.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	105.0	-	-	15.0	-	-	-	-	150.0	15.0	-	285.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	90.0	-	-	-	-	210.0	-	-	300.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	143	261	191	175	226	270	273	300	300	300	300	14	137
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	702	-	-	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	460	-	-	-	-	-	-	-	40	475	-	-	-	-	-	460	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	430	-	-	405	835
	Total Solar	-	-	-	-	-	1,219	-	-	-	-	359	-	-	40	475	-	-	1,132	-	-	1,219	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	26.3	81.4	-	-	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	36	38	39	43	41	39	37	33	31	31	30	26	26	24	26	22	23	385	655
	Energy Efficiency, WA	11	9	10	10	11	12	11	11	11	11	10	9	9	8	7	6	6	5	4	4	108	175
	Energy Efficiency Total	52	48	48	48	51	52	56	54	51	49	45	42	41	40	35	33	32	31	27	27	509	861
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	60	105	-	-	-	-	-	-	-	75	15	60	255
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	60
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	-	120
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	15	75	-	-	-	-	-	15	15	30	30	15	180
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	170	166	244	318	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,047	1,075	1,045	1,046	518	792
	FOT West - Winter	151	131	268	303	314	58	64	68	118	250	224	185	193	140	71	5	18	-	-	-	173	128
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(982)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	124	293	198	230	4,185	153	335	137	315	1,701	1,461	745	259	680	81	107	1,614	2,544	244		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	228	230	312	436	1,468	1,560	1,451	1,443	1,440	1,417	1,352	1,365	1,375	1,345	1,346		
	Total Annual Additions	1,279	974	1,054	1,004	1,042	4,413	383	646	572	1,783	3,261	2,912	2,188	1,700	2,097	1,434	1,471	2,989	3,889	1,590		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-48C	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	185	185	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	185	185	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, UT	-	-	-	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	73
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	73	1,920	-	-	-	-	620	1,100	-	-	-	-	-	-	-	-	1,993	3,713
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	227	-	-	-	-	-	195	305	-	-	-	-	-	-	-	227	727
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	904	-	-	-	-	-	195	305	-	100	-	-	-	909	-	1,127	2,636
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	-	-	74.1
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	1.8	15.3	3.7	151.7	19.1	44.6	379.6
	Energy Efficiency, ID	6	5	6	7	7	7	7	7	7	7	7	6	6	6	6	5	4	3	3	3	67	116
	Energy Efficiency, UT	58	65	67	68	69	66	67	65	65	62	57	56	52	50	49	38	36	26	25	26	652	1,066
	Energy Efficiency, WY	10	10	11	12	15	16	16	17	18	17	16	14	13	12	11	9	8	7	5	5	143	245
	Energy Efficiency Total	74	81	85	86	91	90	91	88	90	87	80	77	72	68	65	51	48	37	33	35	862	1,427
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	375.0	105	-	480.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	150.0	-	-	-	-	-	-	-	225.0	-	-	375.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	135.0	-	-	-	-	120.0	60.0	-	315.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	144	261	300	203	250	299	300	300	300	300	300	14	148
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	-	-	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	-	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	519	-	3	174	6	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	462	-	-	-	-	-	-	-	38	475	-	-	-	-	-	462	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	430	-	-	405	835
	Total Solar	-	-	-	-	-	1,221	-	-	-	-	359	-	-	38	475	519	-	433	174	6	1,221	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	3.1	-	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	45.7	-	3.1	58.9	-	-	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	33
	Energy Efficiency, OR	40	37	37	36	39	41	43	41	39	37	34	31	31	30	27	27	26	26	25	24	389	670
	Energy Efficiency, WA	11	9	10	11	12	12	12	11	11	11	10	9	9	8	8	6	6	5	4	4	109	177
	Energy Efficiency Total	52	48	48	48	53	55	56	54	52	49	46	42	42	40	36	34	33	32	30	29	515	880
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	165	-	-	-	-	-	-	-	75	-	-	240
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	15	-	15	-	-	165
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	45	-	45	-	75	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	170	165	244	318	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	969	1,075	1,073	518	791
	FOT West - Winter	151	131	268	303	314	57	64	68	117	249	224	185	193	140	105	-	-	-	-	-	172	129
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(858)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	129	299	198	235	4,190	155	335	141	316	1,688	1,792	418	293	677	837	785	508	2,211	254		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	227	229	312	436	1,468	1,560	1,560	1,471	1,465	1,478	1,375	1,374	1,269	1,375	1,373		
	Total Annual Additions	1,279	979	1,060	1,004	1,047	4,417	385	647	577	1,784	3,249	3,352	1,889	1,758	2,155	2,212	2,159	1,778	3,586	1,627		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-53CP	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	185	185	-	-	-	-	-	-	-	-	-	185	370
	Total SCCT	-	-	-	-	-	-	-	185	-	185	185	370	-	-	-	-	-	-	-	-	370	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	127	493	-	-	-	-	-	-	-	-	-	127	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,091	-	-	-	-	-	-	-	-	-	1,091
	Wind, UT	-	-	-	-	294	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	294	294
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	294	1,920	-	-	-	127	493	1,091	-	-	-	-	-	-	-	-	2,341	3,925
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	6	-	-	-	-	-	-	500	-	-	-	-	-	-	-	6	506
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-	-	-	-	9
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	683	-	-	-	-	-	-	509	-	100	-	-	-	909	-	906	2,424
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	18.7
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	18.6	161.2	379.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	68	116
	Energy Efficiency, UT	58	61	67	68	69	66	67	65	65	62	57	56	52	50	49	36	36	25	20	22	647	1,049
	Energy Efficiency, WY	10	10	11	12	13	16	16	17	17	17	16	14	13	12	11	9	8	7	5	5	139	238
	Energy Efficiency Total	74	77	85	86	89	90	91	88	89	86	79	76	71	67	65	49	48	35	28	30	855	1,403
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	360.0	135	-	495.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	210.0	-	180.0	-	-	390.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	195.0	-	-	15.0	-	105.0	45.0	-	360.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	205	239	164	178	235	247	250	267	300	300	300	20	134
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	221	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	221	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	384	-	-	349	-	-	-	682	-	-	-	-	-	384	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	430	-	405	835
	Total Solar	-	-	-	-	-	905	-	384	-	-	349	-	-	-	1,157	-	-	-	430	-	1,289	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	23.2	-	-	-	22.4	-	-	-	52.8	-	9.4	107.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	40	42	47	46	43	41	39	37	33	31	30	30	26	26	26	25	22	21	410	678
	Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	10	10	9	9	8	8	6	6	5	4	4	111	178
	Energy Efficiency Total	52	48	52	55	61	59	56	55	52	49	45	42	40	40	35	33	33	30	27	26	539	889
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	30	-	-	210	-	-	-	-	-	15	-	-	-	30	255
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	75
	Battery Storage - Portland NC	-	-	-	-	-	-	-	30	-	-	30	-	-	-	-	-	30	-	-	-	30	90
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	30	-	105	-	-	-	-	-	-	-	15	-	30	150
	Battery Storage - Yakima	-	-	-	-	-	-	-	90	-	-	15	-	-	-	-	-	-	-	-	-	90	105
	FOT West - Summer	998	719	492	501	496	92	86	578	650	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,063	1,042	1,075	1,075	569	820
	FOT West - Winter	151	131	265	300	310	33	37	38	85	217	254	213	222	170	69	7	16	9	-	-	157	126
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,212)	(85)	(912)	(442)	(396)	(350)	(114)	(911)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	125	303	205	462	3,657	155	869	170	573	1,616	1,587	620	314	1,382	82	580	65	2,492	254		
	Annual Additions, Short Term Resources	1,149	850	757	801	806	125	123	616	735	1,497	1,568	1,452	1,475	1,479	1,391	1,332	1,347	1,351	1,375	1,375		
	Total Annual Additions	1,279	976	1,060	1,005	1,268	3,782	278	1,486	905	2,070	3,184	3,039	2,094	1,794	2,773	1,414	1,926	1,416	3,867	1,629		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.15 – Preferred Portfolio, Detailed Capacity Expansion Portfolio

		Capacity (MW)																				Resource Totals 1/	
	P-45CNW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gads by 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	370	-	185	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,040	-	-	-	-	-	-	-	-	-	1,040
	Wind, UT	-	-	-	-	69	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	69	69
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	60
	Total Wind	-	-	-	-	69	1,920	-	-	-	-	-	1,040	-	60	-	-	-	-	-	-	1,989	3,089
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	231	-	-	-	-	-	500	-	-	-	-	-	-	-	-	231	731
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	3	674	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	3	904	-	-	-	-	-	500	-	-	-	-	-	-	909	-	1,131	2,540
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Themostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	37.3
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Themostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	1.2	-	6.7
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	3.7	10.5	136.5	44.6	354.1
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	68	67	65	65	62	57	56	52	52	48	36	32	25	22	23	656	1,058
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	18	17	16	15	13	12	11	9	8	7	5	5	146	248
	Energy Efficiency Total	74	83	85	88	92	92	91	90	90	87	80	77	72	70	65	49	45	35	30	32	870	1,423
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195	-	195.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	30.0	-	-	-	-	-	-	150.0	-	180.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	88	300	199	174	206	298	300	300	300	300	300	9	138
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hemiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind+Storage, YK	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	11	-	-	20
	Total Wind	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	11	-	-	20
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	395	-	-	-	-	-	-	-	-	-	-	-	419	-	-	395	815
	Total Solar	-	-	-	-	-	1,249	-	-	-	-	359	-	-	-	475	-	-	419	-	702	1,249	3,205
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Themostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Themostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	48.8	32.1	-	90.2
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	42	41	46	43	41	41	38	35	32	31	30	26	26	25	25	24	23	405	680
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	11	10	9	9	8	8	6	6	5	4	4	111	179
	Energy Efficiency Total	52	49	48	55	55	59	56	54	54	51	46	43	42	40	35	33	33	30	29	28	533	892
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	210	-	-	60	-	-	-	-	-	180	-	450
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	75	45	-	-	-	-	-	-	-	-	-	75	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	75	-	-	60	-	-	-	-	-	60	-	195
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	131	126	191	264	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	977	1,074	1,075	500	782
	FOT West - Winter	151	131	268	303	314	44	51	53	100	232	222	173	192	128	63	-	35	-	-	-	165	123
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	132	299	206	237	4,225	155	336	143	318	1,063	2,038	144	303	574	82	93	488	2,355	1,530		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	175	177	244	364	1,394	1,597	1,447	1,441	1,409	1,435	1,375	1,410	1,277	1,374	1,375		
	Total Annual Additions	1,279	982	1,060	1,012	1,049	4,400	333	580	507	1,712	2,661	3,485	1,584	1,712	2,010	1,457	1,503	1,765	3,729	2,905		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.16 – FOT Risk Assessment Cases, Detailed Capacity Expansion Portfolio

P-45CP-FOT	Capacity (MW)																				Resource Totals 1/	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
Existing Plant Retirements and PPA Termination																						
Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
Expansion Resources																						
SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	185	185	-	-	-	-	-	-	-	185	555
SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	185	-	-	-	-	-	185	-	-	370
Total SCCT	-	-	-	-	-	-	-	185	-	-	-	185	370	-	-	-	-	-	185	-	185	925
Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
Wind, CO	-	-	-	-	-	-	-	-	-	-	-	839	-	-	-	-	-	-	-	-	-	839
Wind, UT	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	130	130
Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
Total Wind	-	-	-	-	130	1,920	-	-	-	-	620	839	-	-	-	-	-	-	-	-	2,050	3,508
Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	170	-	-	-	-	-	-	-	500	-	-	-	-	-	-	170	670
Utility Solar+Storage - PV - CO	-	-	-	-	-	-	-	-	-	-	-	261	-	-	-	-	-	-	-	-	-	261
Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	715	-	-	715
Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
Total Solar	-	-	159	64	-	847	-	-	-	-	-	261	-	500	-	-	-	-	715	-	1,070	2,546
Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
Demand Response, UT-Thermostat	-	-	-	-	-	-	-	33.5	45.8	37.3	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	1.8
Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
Demand Response, UT-Ancillary Services	-	-	-	-	-	-	13.5	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
Demand Response Total	4.1	-	7.0	-	9.9	-	16.5	40.7	45.8	37.3	6.7	10.0	-	12.0	18.7	-	15.3	3.7	133.0	21.6	161.2	382.2
Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	68	116
Energy Efficiency, UT	58	67	67	68	69	67	67	65	65	62	56	56	50	50	47	35	32	25	20	23	655	1,049
Energy Efficiency, WY	10	10	11	12	15	16	16	18	18	17	15	15	13	12	11	9	8	7	5	5	144	244
Energy Efficiency Total	74	83	85	87	91	91	91	90	90	86	78	77	69	67	63	48	45	35	28	31	868	1,408
Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	15
Battery Storage - Utah-S	-	-	-	-	-	-	-	-	15.0	-	210.0	-	-	-	-	-	-	-	120.0	420	15.0	765.0
Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	45.0	75.0	-	-	-	-	-	-	-	60.0	165.0	45.0	345.0
Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	15.0	15.0	-	-	-	-	-	255.0	90.0	-	375.0
FOT East - Summer	42	42	-	-	-	-	-	70	67	150	180	150	150	150	150	150	150	150	300	260	37	108
Existing Plant Retirements and PPA Termination																						
JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
Retire - Hydro	-	(1)	(169)	-	(1)	-	-	-	(1)	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
Expansion Resources																						
SCCT Frame WY	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
Utility Solar+Storage - PV - Yakima	-	-	-	-	-	391	-	-	-	-	-	-	-	-	-	-	-	-	444	-	391	835
Total Solar	-	-	-	-	-	1,245	-	-	-	-	359	-	-	475	-	-	-	-	444	702	1,245	3,225
Demand Response, OR-Ancillary Services	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
Demand Response, WA-Ancillary Services	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	-	-	30.3	2.0	-	37.7
Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	4.1	-	9.2	-	-	-	-	-	-	-	-	-	4.1	13.3
Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	1.1	-	10.9
Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	3.1	-	-	-	5.2	8.3
Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	14.6	-	-	-	2.0	-	-	-	-	-	-	16.6
Demand Response Total	-	-	-	-	-	7.5	1.9	-	4.1	5.2	34.4	-	5.4	-	2.0	-	3.1	-	73.8	3.0	18.6	140.4
Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
Energy Efficiency, OR	40	37	37	36	39	45	43	41	39	37	33	31	30	30	26	26	26	26	24	23	393	666
Energy Efficiency, WA	11	9	9	11	11	12	12	11	11	11	9	9	9	8	7	6	6	5	4	4	107	175
Energy Efficiency Total	52	48	47	48	52	59	56	54	52	49	44	43	40	40	35	33	33	32	29	27	518	874
Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	105	60	-	-	-	-	-	-	-	90	-	105	255
Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60	-	-	60
Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	30	30
Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	30	30	-	-	-	-	-	-	-	-	-	30	60
FOT West - Summer	956	678	492	500	496	107	99	100	141	927	1,075	812	620	432	795	797	794	804	1,075	1,075	449	639
FOT West - Winter	151	131	265	300	311	39	43	44	91	223	244	243	271	169	187	204	219	294	-	100	160	176
Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
Annual Additions, Long Term Resources	130	131	298	198	283	4,169	165	369	207	388	1,518	1,430	499	1,094	118	81	96	71	2,650	1,460		
Annual Additions, Short Term Resources	1,149	850	757	800	807	145	142	214	299	1,300	1,499	1,205	1,041	751	1,132	1,151	1,163	1,248	1,375	1,435		
Total Annual Additions	1,279	982	1,055	998	1,090	4,315	307	583	506	1,688	3,017	2,635	1,540	1,846	1,250	1,232	1,259	1,318	4,025	2,895		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-46CP-FOT	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	370	-	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	33	587	-	-	-	-	-	-	-	-	-	33	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,010	-	-	-	-	-	-	-	-	-	1,010
	Wind, UT	-	-	-	-	145	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	145	145
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	145	1,920	-	-	-	33	587	1,010	-	-	-	-	-	-	-	-	2,097	3,695
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	155	-	-	-	-	-	-	-	500	-	-	-	-	-	-	155	655
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	90	-	-	-	-	-	-	-	-	-	90
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	832	-	-	-	-	-	90	-	500	-	-	-	-	909	-	1,055	2,554
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	116.7	-	-	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	-	-	13.5	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	9.9	-	16.5	123.8	-	-	6.7	10.0	-	12.0	18.7	-	15.3	3.7	133.0	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	69	118
	Energy Efficiency, UT	58	67	67	68	71	68	71	68	65	62	57	56	52	52	53	36	32	25	22	24	665	1,074
	Energy Efficiency, WY	10	10	11	12	15	16	16	17	17	16	14	14	12	11	11	9	8	7	5	5	140	237
	Energy Efficiency Total	74	83	85	86	94	92	95	92	89	85	78	76	71	69	69	49	44	35	30	33	875	1,428
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	540.0	90	-	630.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	15.0	-	-	30.0	-	-	-	-	-	120.0	-	180.0	-	15.0	345.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	105.0	45.0	-	-	-	-	135.0	30.0	-	315.0
	FOT East - Summer	42	42	-	-	-	-	-	144	150	150	150	150	150	150	216	218	214	223	299	295	53	130
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	534	-	-	349	-	-	-	533	-	-	-	-	-	534	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	401	-	-	-	-	-	-	-	-	3	-	-	-	430	-	401	835
	Total Solar	-	-	-	-	-	901	-	534	-	-	349	-	-	-	1,011	-	-	-	430	-	1,435	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.0	-	-	12.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	-	-	30.3	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	4.1	-	-	-	9.2	-	-	-	-	-	-	-	-	-	4.1	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	1.1	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	3.1	-	-	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	14.6	-	-	-	2.0	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	7.5	5.9	5.2	-	-	34.4	-	5.4	-	2.0	-	3.1	-	62.5	3.0	18.6	129.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	48	47	46	43	43	39	38	34	32	31	31	28	26	24	26	24	24	417	698
	Energy Efficiency, WA	11	9	10	11	12	12	12	12	11	11	10	9	9	8	8	6	6	5	4	4	111	180
	Energy Efficiency Total	52	48	49	60	61	59	57	57	52	51	46	44	42	42	38	32	32	32	29	29	546	911
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	15	15	225	15	-	-	-	-	-	-	-	-	45	255	315
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	-	-	15	15
	Battery Storage - Portland NC	-	-	-	-	-	-	-	30	15	-	-	-	-	-	-	-	-	-	60	-	45	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	15	-	60	75
	Battery Storage - Yakima	-	-	-	-	-	-	-	15	45	-	-	-	-	-	-	-	-	-	-	-	60	60
	FOT West - Summer	956	678	491	500	496	100	88	100	166	1,060	1,075	817	949	885	1,075	1,075	1,075	1,075	1,075	1,074	464	741
	FOT West - Winter	151	131	265	300	311	36	40	41	88	220	242	239	268	295	201	217	232	306	100	100	158	189
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,207)	(85)	(912)	(444)	(396)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	131	300	211	309	3,812	174	1,146	215	394	1,516	1,599	223	668	1,139	81	657	70	2,523	251		
	Annual Additions, Short Term Resources	1,149	850	757	800	807	136	128	285	404	1,430	1,467	1,207	1,367	1,330	1,491	1,510	1,521	1,604	1,474	1,469		
	Total Annual Additions	1,279	981	1,056	1,011	1,116	3,948	302	1,431	620	1,825	2,983	2,806	1,590	1,998	2,631	1,591	2,179	1,675	3,997	1,720		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-47CP-FOT	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	370	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,009	66	-	-	-	-	-	-	-	-	1,075
	Wind, UT	-	-	-	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	73
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	73	1,920	-	-	-	-	620	1,009	66	-	-	-	-	-	-	-	1,993	3,688
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	227	-	-	-	-	-	-	-	500	-	-	-	-	-	-	227	727
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	25	-	-	-	-	-	-	-	-	-	25
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	904	-	-	-	-	-	25	-	500	-	-	-	-	909	-	1,127	2,561
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	33.5	59.0	24.1	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	-	-	13.5	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	9.9	-	16.5	40.7	59.0	24.1	6.7	10.0	-	12.0	18.7	-	15.3	3.7	133.0	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	5	4	4	3	3	3	68	115
	Energy Efficiency, UT	58	65	67	68	69	66	65	65	62	62	54	53	50	48	47	36	32	26	22	22	646	1,035
	Energy Efficiency, WY	10	10	11	12	15	16	16	17	17	17	15	14	12	12	11	9	8	7	5	5	141	239
	Energy Efficiency Total	74	81	85	86	91	89	89	88	85	86	76	73	68	65	63	49	44	36	30	30	855	1,389
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	255.0	-	-	-	-	-	-	-	330.0	120	-	705.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	315.0	-	-	315.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45.0	240.0	60.0	-	345.0
	FOT East - Summer	42	42	-	-	-	-	-	48	37	150	173	150	150	150	150	150	150	173	300	292	32	108
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	SCCT Frame YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	233	-	-	-	233
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	233	443	-	-	676
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	702	-	-	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	197	-	-	405	602
	Total Solar	-	-	-	-	-	1,259	-	-	-	-	359	-	-	475	-	-	-	899	-	-	1,259	2,992
	Demand Response, OR-Ancillary Services	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.4	-	-	16.4
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	-	-	30.3	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	4.1	-	9.2	-	-	-	-	-	-	-	-	-	4.1	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	1.1	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	3.1	-	-	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	14.6	-	-	-	2.0	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	7.5	1.9	-	4.1	5.2	34.4	-	5.4	-	2.0	-	3.1	-	66.9	3.0	18.6	133.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	31
	Energy Efficiency, OR	40	32	37	36	39	39	39	41	39	37	33	31	30	29	26	26	26	26	24	23	378	650
	Energy Efficiency, WA	11	9	9	10	11	11	11	11	11	10	9	9	8	8	7	6	6	5	4	4	105	172
	Energy Efficiency Total	52	43	47	48	52	51	52	54	51	49	44	41	40	38	35	34	33	32	29	27	500	853
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	135
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	75	75
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	30
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	60	60
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	30	30	-	-	-	-	-	-	-	-	-	30	60
	FOT West - Summer	956	678	492	500	497	120	112	113	154	920	1,075	857	662	474	837	839	836	1,075	1,070	1,046	454	666
	FOT West - Winter	151	131	265	300	311	39	43	44	91	223	244	243	271	169	187	203	218	251	100	100	160	179
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(982)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	124	298	198	226	4,232	159	368	200	329	1,561	1,528	549	1,090	118	82	96	1,278	2,496	261		
	Annual Additions, Short Term Resources	1,149	850	757	800	808	159	155	206	282	1,293	1,492	1,250	1,083	793	1,174	1,193	1,204	1,499	1,470	1,438		
	Total Annual Additions	1,279	974	1,055	998	1,033	4,390	314	574	482	1,623	3,052	2,778	1,632	1,883	1,292	1,275	1,300	2,777	3,966	1,700		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-48CP-FOT	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	370	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, CO	-	-	-	-	-	-	-	-	-	-	-	1,055	45	-	-	-	-	-	-	-	-	1,100
	Wind, UT	-	-	-	-	261	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	261	261
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	261	1,920	-	-	-	-	620	1,055	45	-	-	-	-	-	-	-	2,181	3,901
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	39	-	-	-	-	-	-	500	-	-	-	-	-	-	-	39	539
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	716	-	-	-	-	-	-	500	-	-	-	-	-	909	-	939	2,348
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	55.2	-	-	18.9	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	33.5	59.0	24.1	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	-	-	13.5	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	9.9	-	16.5	40.7	59.0	24.1	6.7	10.0	-	12.0	20.5	55.2	15.3	3.7	75.9	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	5	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	67	67	66	65	62	54	53	52	50	49	39	36	26	24	31	655	1,069
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	19	17	14	14	13	12	11	9	8	7	5	6	147	247
	Energy Efficiency Total	74	83	85	88	91	90	91	92	91	86	75	74	71	67	66	53	48	37	32	40	871	1,433
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75.0	-	765.0	60	-	900.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	255.0	-	-	-	-	255.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	60.0	180.0	-	-	120.0	-	360.0
	FOT East - Summer	42	42	-	-	-	-	-	118	106	150	150	150	150	150	150	270	242	251	298	300	46	129
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	-	-	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	-	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	221
	SCCT Frame YK	-	-	-	-	-	-	-	-	-	233	-	-	-	-	-	-	-	-	-	-	233	233
	Total SCCT	-	-	-	-	-	-	-	-	-	233	-	-	-	-	-	-	-	-	221	-	233	455
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	438	102	-	146	16	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	85	390	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	172	-	-	-	-	-	-	-	-	-	-	-	-	430	-	172	602
	Total Solar	-	-	-	-	-	1,026	-	-	-	-	359	-	85	390	-	438	102	-	576	16	1,026	2,992
	Demand Response, OR-Ancillary Services	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	30.3	-	-	-	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	4.1	-	-	9.2	-	-	-	-	-	-	-	-	-	4.1	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	-	1.1	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	3.1	-	-	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	14.6	-	-	-	2.0	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	7.5	1.9	4.1	-	5.2	34.4	-	5.4	-	2.0	41.3	3.1	-	3.0	3.0	18.6	110.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	32	37	36	36	39	41	41	39	37	33	31	30	29	26	26	26	25	22	23	375	643
	Energy Efficiency, WA	11	9	9	10	11	12	12	11	11	10	9	9	8	8	7	6	6	5	4	4	107	173
	Energy Efficiency Total	52	43	47	48	48	52	54	54	52	49	44	41	40	38	35	33	33	30	27	27	499	848
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	90	180	-	-	-	-	-	-	-	-	-	90	270
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	30	15	-	-	-	-	-	-	-	-	-	-	45	45
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	15
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	90	30	-	-	-	-	-	-	-	-	-	90	120
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	15	-	15	30
	FOT West - Summer	956	678	492	500	496	125	117	115	158	790	968	731	394	349	710	1,075	1,075	1,075	1,031	1,006	443	642
	FOT West - Winter	151	131	265	300	311	88	93	94	141	38	58	57	64	-	1	18	33	109	-	100	161	103
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(858)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	126	298	199	410	3,812	163	376	246	593	1,365	1,550	1,117	507	123	680	712	71	2,624	288		
	Annual Additions, Short Term Resources	1,149	850	757	800	807	214	210	327	405	978	1,176	939	608	499	862	1,364	1,350	1,435	1,329	1,406		
	Total Annual Additions	1,279	977	1,055	999	1,217	4,026	373	703	651	1,571	2,541	2,488	1,725	1,006	985	2,043	2,062	1,506	3,953	1,694		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-53CP-FOT	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	370	-	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	33	587	-	-	-	-	-	-	-	-	-	33	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,010	-	-	-	-	-	-	-	-	-	1,010
	Wind, UT	-	-	-	-	145	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	145	145
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	145	1,920	-	-	-	33	587	1,010	-	-	-	-	-	-	-	-	2,097	3,695
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	155	-	-	-	-	-	-	-	500	-	-	-	-	-	-	155	655
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	90	-	-	-	-	-	-	-	-	-	90
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	832	-	-	-	-	-	90	-	500	-	-	-	-	909	-	1,055	2,554
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	116.7	-	-	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	-	-	13.5	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	9.9	-	16.5	123.8	-	-	6.7	10.0	-	12.0	18.7	-	15.3	3.7	133.0	21.6	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	69	118
	Energy Efficiency, UT	58	67	67	68	71	68	71	68	65	62	57	56	52	52	53	36	32	25	22	24	665	1,074
	Energy Efficiency, WY	10	10	11	12	15	16	16	17	17	16	14	14	12	11	11	9	8	7	5	5	140	237
	Energy Efficiency Total	74	83	85	86	94	92	95	92	89	85	78	76	71	69	69	49	44	35	30	33	875	1,428
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	540.0	90	-	630.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	15.0	-	-	30.0	-	-	-	-	-	120.0	-	180.0	-	15.0	345.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	105.0	45.0	-	-	-	-	135.0	30.0	-	315.0
	FOT East - Summer	42	42	-	-	-	-	-	144	150	150	150	150	150	150	216	218	214	223	299	295	53	130
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	534	-	-	349	-	-	-	533	-	-	-	-	-	534	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	401	-	-	-	-	-	-	-	-	3	-	-	-	430	-	401	835
	Total Solar	-	-	-	-	-	901	-	534	-	-	349	-	-	-	1,011	-	-	-	430	-	1,435	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.0	-	-	12.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	-	-	30.3	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	4.1	-	-	-	9.2	-	-	-	-	-	-	-	-	-	4.1	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	1.1	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	3.1	-	-	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	14.6	-	-	-	2.0	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	7.5	5.9	5.2	-	-	34.4	-	5.4	-	2.0	-	3.1	-	62.5	3.0	18.6	129.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	48	47	46	43	43	39	38	34	32	31	31	28	26	24	26	24	24	417	698
	Energy Efficiency, WA	11	9	10	11	12	12	12	12	11	11	10	9	9	8	8	6	6	5	4	4	111	180
	Energy Efficiency Total	52	48	49	60	61	59	57	57	52	51	46	44	42	42	38	32	32	32	29	29	546	911
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	15	15	225	15	-	-	-	-	-	-	-	-	45	255	315
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	-	-	15	15
	Battery Storage - Portland NC	-	-	-	-	-	-	-	30	15	-	-	-	-	-	-	-	-	-	60	-	45	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	15	-	60	75
	Battery Storage - Yakima	-	-	-	-	-	-	-	15	45	-	-	-	-	-	-	-	-	-	-	-	60	60
	FOT West - Summer	956	678	491	500	496	100	88	100	166	1,060	1,075	817	949	885	1,075	1,075	1,075	1,075	1,075	1,074	464	741
	FOT West - Winter	151	131	265	300	311	36	40	41	88	220	242	239	268	295	201	217	232	306	100	100	158	189
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,212)	(85)	(912)	(442)	(396)	(350)	(114)	(911)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	131	300	211	309	3,812	174	1,146	215	394	1,516	1,599	223	668	1,139	81	657	70	2,523	251		
	Annual Additions, Short Term Resources	1,149	850	757	800	807	136	128	285	404	1,430	1,467	1,207	1,367	1,330	1,491	1,510	1,521	1,604	1,472	1,469		
	Total Annual Additions	1,279	981	1,056	1,011	1,116	3,948	302	1,431	620	1,824	2,983	2,806	1,590	1,998	2,631	1,591	2,179	1,675	3,997	1,720		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-45CNW-FOT	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	370	-	-	-	-	-	-	-	-	185	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, UT	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150	150
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	150	1,920	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	2,070	3,170
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	150	-	-	-	-	-	-	500	-	-	-	-	-	-	-	150	650
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	827	-	-	-	-	-	-	500	-	-	-	-	-	909	-	1,050	2,459
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	33.5	-	83.1	-	8.2	-	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.1	37.3	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	-	-	13.5	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	9.9	-	16.5	40.7	-	83.1	6.7	10.0	-	12.0	18.7	-	15.3	3.7	81.3	73.3	161.2	382.2
	Energy Efficiency, ID	6	6	6	7	7	8	7	7	7	7	7	6	6	6	6	4	4	4	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	71	70	71	64	62	61	57	56	52	50	49	38	36	29	20	22	658	1,066
	Energy Efficiency, WY	10	10	13	14	15	18	19	17	18	17	16	15	13	12	11	9	8	7	5	5	150	253
	Energy Efficiency Total	74	83	86	88	94	96	97	87	86	85	80	77	72	68	66	51	48	40	28	30	877	1,436
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	765.0	-	-	-	765.0
	Battery Storage - WYSW	-	-	-	-	-	-	15.0	-	-	-	-	-	-	-	-	-	-	180.0	-	-	15.0	195.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	75.0	75.0	-	-	-	-	240.0	-	-	-	390.0
	FOT East - Summer	42	42	-	-	-	-	-	78	106	150	150	150	150	150	150	150	150	150	185	150	42	98
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	47	-	-	-	-	-	-	-	47
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	47	-	-	-	-	-	-	-	47
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	358	-	-	-	-	-	-	-	-	-	-	-	-	430	-	358	788
	Total Solar	-	-	-	-	-	1,212	-	-	-	-	359	-	-	475	-	-	-	-	430	702	1,212	3,178
	Demand Response, OR-Ancillary Services	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	20.3	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	-	30.3	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	4.1	-	9.2	-	-	-	-	-	-	-	-	-	4.1	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	1.1	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	3.1	-	-	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	14.6	-	-	-	2.0	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	7.5	1.9	-	4.1	5.2	34.4	-	-	5.4	2.0	-	3.1	-	44.3	32.5	18.6	140.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	36	43	42	40	46	43	35	39	37	33	32	30	30	27	27	26	28	22	23	399	675
	Energy Efficiency, WA	11	9	10	11	12	12	12	11	11	10	9	9	8	8	7	6	6	5	4	4	109	176
	Energy Efficiency Total	52	47	54	55	54	59	56	48	52	49	44	43	40	40	36	34	33	33	27	27	526	884
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	60	15	30	-	-	-	-	-	735	-	-	60	840
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	15	30	-	-	-	-	-	-	-	210	-	-	45	255
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	15	-	-	-	30
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	45	15	15	-	-	-	-	-	30	-	-	45	105
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	15	-	-	30	45
	FOT West - Summer	956	678	492	500	496	108	100	101	142	936	1,054	569	585	495	859	861	858	867	1,075	1,072	451	640
	FOT West - Winter	151	131	265	300	311	46	50	52	99	231	251	250	278	170	187	204	219	295	-	100	164	179
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	131	307	206	307	4,122	187	361	157	387	924	1,720	686	647	123	85	115	2,267	2,025	864		
	Annual Additions, Short Term Resources	1,149	850	757	800	807	154	150	231	347	1,317	1,455	969	1,013	815	1,196	1,215	1,227	1,312	1,260	1,322		
	Total Annual Additions	1,279	981	1,063	1,007	1,114	4,276	337	592	503	1,704	2,379	2,689	1,700	1,462	1,319	1,300	1,342	3,579	3,285	2,187		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.17 – Gateway & No Gas Cases, Detailed Capacity Expansion Portfolio

		Capacity (MW)																				Resource Totals 1/	
	P-22	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - Dlohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	185	185	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	185	185	-	-	925
	Wind, OO	-	-	-	-	-	-	-	-	-	-	-	1,033	-	-	-	-	-	-	-	-	-	1,033
	Wind, UT	-	-	-	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	73
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, OO	-	-	-	-	-	-	-	-	-	-	-	-	-	67	-	-	-	-	-	-	-	67
	Total Wind	-	-	-	-	73	1,920	-	-	-	-	-	1,033	-	67	-	-	-	-	-	-	1,993	3,093
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	227	-	-	-	-	-	272	228	-	-	-	-	-	-	-	227	727
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	904	-	-	-	-	-	272	228	-	100	-	-	-	909	-	1,127	2,636
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.1	37.3	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	-	31.2	139.2	44.6	373.9
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	68	113
	Energy Efficiency, UT	58	61	67	68	69	66	65	65	62	62	57	58	54	48	47	36	32	25	22	25	642	1,044
	Energy Efficiency, WY	10	10	11	12	15	16	16	17	18	18	16	15	13	12	11	9	8	7	5	5	143	245
	Energy Efficiency Total	74	77	85	86	91	89	89	89	86	87	80	79	73	65	63	49	45	35	30	33	853	1,404
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	90.0	-	-	-	-	-	-	390.0	-	480.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	60.0	90.0	-	-	-	-	-	-	30.0	-	180.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	52	300	295	216	236	285	287	300	300	300	300	5	144
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind, Jbridger	-	-	-	-	-	-	-	200	-	-	359	-	-	-	-	-	-	-	-	-	200	559
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	298	-	-	298
	Total Wind	-	-	-	-	-	-	-	200	-	-	359	-	-	-	-	-	-	-	298	-	200	858
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	-	-	-	-	-	-	-	-	-	702	354	1,056
	Utility Solar+Storage - PV - Borah	-	-	-	-	-	-	-	300	-	-	-	-	-	-	-	-	-	-	-	-	300	300
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	463	-	-	-	-	-	-	-	37	475	-	-	-	-	-	463	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	132	-	405	537
	Total Solar	-	-	-	-	-	1,222	-	300	-	-	-	-	-	37	475	-	-	-	132	702	1,522	2,868
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26.8	10.9	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	78.6	32.1	-	120.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	37	39	39	43	41	39	37	33	32	31	29	26	26	24	25	24	24	388	660
	Energy Efficiency, WA	11	9	10	11	12	12	12	11	11	11	9	9	9	8	7	6	6	5	4	4	109	176
	Energy Efficiency Total	52	48	48	49	53	52	56	54	52	49	44	43	42	38	35	33	32	31	29	29	514	869
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	165	-	165
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	-	-	-	210
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	75	-	135	-	-	-	-	-	-	30	-	75	240
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	167	162	164	228	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,062	1,075	1,075	1,074	501	787
	FOT West - Winter	151	131	268	303	314	56	63	65	114	246	223	183	192	138	92	3	15	9	-	-	171	128
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	125	299	199	235	4,188	153	650	138	316	616	2,396	523	219	673	81	92	251	2,670	1,520		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	223	225	229	342	1,373	1,598	1,553	1,483	1,449	1,452	1,365	1,377	1,384	1,375	1,374		
	Total Annual Additions	1,279	975	1,060	1,005	1,047	4,411	378	879	479	1,689	2,214	3,950	2,006	1,668	2,124	1,447	1,469	1,635	4,045	2,893		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-23	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	195	-	195	195	-	-	-	-	-	-	584
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370	370
	Total SCCT	-	-	-	-	-	-	-	185	-	370	-	564	-	195	195	-	-	-	-	-	555	1,508
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, UT	-	-	-	-	131	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	131	131
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	131	1,920	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	2,051	3,151
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	169	-	-	-	-	-	-	-	-	500	-	-	-	-	-	169	669
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	846	-	-	-	-	-	-	-	-	600	-	-	-	909	-	1,069	2,578
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	-	-	74.1
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	-	8.2	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	2.1	-	-	-	-	16.7	-	-	18.7
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	116.7	6.7	-	8.2	14.0	1.8	-	7.0	-	150.7	16.1	161.2	365.7
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	7	6	6	5	4	4	3	3	3	70	117
	Energy Efficiency, UT	58	67	67	68	71	68	71	68	65	62	57	59	52	50	47	34	31	25	20	22	665	1,061
	Energy Efficiency, WY	10	10	13	14	15	16	17	19	18	18	16	15	13	12	11	9	8	7	5	5	150	251
	Energy Efficiency Total	74	83	86	88	94	92	96	94	90	87	80	81	71	68	63	47	43	35	28	30	885	1,429
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0	195	-	225.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	-	-	-	15.0	-	-	30.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135.0	-	-	135.0
	FOT East - Summer	-	-	-	-	-	-	-	21	49	191	205	121	252	300	213	215	220	291	300	300	26	134
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind, Jbridger	-	-	-	-	-	-	-	200	-	620	-	-	-	-	-	-	-	-	-	-	820	820
	Wind, Borah	-	-	-	-	-	-	-	-	488	-	-	-	-	-	-	-	-	-	-	-	488	488
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	5
	Total Wind	-	-	-	-	-	-	-	200	488	620	-	-	-	-	-	-	-	-	5	-	1,308	1,314
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	254	126	56	-	-	-	-	-	-	-	-	254	436
	Utility Solar+Storage - PV - Borah	-	-	-	-	-	-	-	300	112	-	-	-	-	-	-	-	-	-	-	-	412	412
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	425	-	405	830
	Total Solar	-	-	-	-	-	905	-	300	112	254	126	56	-	-	475	-	-	-	425	-	1,570	2,652
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.4	-	-	16.4
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	6.5	-	-	-	-	5.3	-	-	11.8
	Demand Response Total	-	-	-	-	-	-	-	-	-	22.6	-	-	-	11.3	5.2	-	-	-	86.5	2.0	22.6	127.6
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	32
	Energy Efficiency, OR	40	37	37	42	47	46	43	43	39	37	34	32	30	30	26	26	24	25	22	21	408	678
	Energy Efficiency, WA	11	10	11	11	12	12	12	12	11	11	10	9	9	8	8	6	6	5	4	4	113	180
	Energy Efficiency Total	52	48	49	55	61	60	57	57	52	49	46	44	40	40	35	32	31	30	27	26	539	891
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	255	-	-	-	-	-	15	-	-	-	-	150	105	255	525
	Battery Storage - Portland NC	-	-	-	-	-	-	-	75	-	-	-	-	-	15	-	-	-	-	-	15	75	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	60	-	75	135
	Battery Storage - Yakima	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	720	318	352	383	-	-	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,018	1,075	1,075	599	834
	FOT West - Winter	104	101	107	72	72	-	-	-	-	29	-	-	-	-	-	-	-	-	-	-	48	24
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,914)	(85)	(912)	(93)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	132	309	207	295	3,822	161	1,353	742	1,519	259	1,845	120	373	1,375	79	81	65	2,464	388		
	Annual Additions, Short Term Resources	1,101	820	424	424	454	-	-	1,096	1,124	1,296	1,280	1,196	1,327	1,375	1,288	1,290	1,295	1,309	1,375	1,375		
	Total Annual Additions	1,231	952	734	631	750	3,822	161	2,449	1,866	2,815	1,539	3,041	1,447	1,748	2,663	1,370	1,376	1,374	3,839	1,763		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-25	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	584	-	-	-	-	-	-	-	-	-	584
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	1,138	-	-	-	-	-	-	370	-	-	1,508
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	1,920	3,020
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	300	-	-	-	-	-	-	500	-	-	-	-	-	-	-	300	800
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	715	-	-	715
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	73	604	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	73	904	-	-	-	-	-	-	500	-	100	-	-	-	715	-	1,200	2,515
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	3.4
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.1	37.3	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	3.7	31.0	131.3	44.6	369.4
	Energy Efficiency, ID	6	5	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	67	115
	Energy Efficiency, UT	58	61	67	68	69	66	67	65	62	62	57	56	52	50	51	36	32	26	23	26	644	1,053
	Energy Efficiency, WY	10	10	11	12	15	16	16	17	18	17	16	15	13	12	11	9	8	7	5	6	143	246
	Energy Efficiency Total	74	76	85	86	91	89	91	88	86	87	80	77	72	68	68	49	45	37	31	35	853	1,414
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	-	300.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105.0	60.0	-	165.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	52	300	224	242	266	298	300	299	88	300	300	5	133
	FOT East - Winter	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	15
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind, Jbridger	-	-	-	-	-	-	-	200	-	-	359	-	-	-	-	-	-	-	-	-	200	559
	Wind, Borah	-	-	-	-	-	-	-	76	600	-	-	-	-	-	-	-	-	-	-	-	676	676
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	430
	Total Wind	-	-	-	-	-	-	-	276	600	-	359	-	-	-	-	-	-	-	-	430	876	1,665
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	-	-	-	-	-	-	-	-	-	702	354	1,056
	Utility Solar+Storage - PV - Borah	-	-	-	-	-	-	-	224	-	-	-	-	-	-	-	-	-	-	-	-	224	224
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	309	-	-	-	-	-	-	-	128	538	-	-	-	-	-	309	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Total Solar	-	-	-	-	-	1,068	-	224	-	-	-	-	-	128	538	-	-	-	-	702	1,293	2,660
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	1.1	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	118.8	12.2	-	140.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	33
	Energy Efficiency, OR	40	37	37	37	39	46	43	41	41	38	34	32	31	30	27	26	26	26	25	24	398	679
	Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	11	10	9	9	8	8	6	6	5	4	4	111	181
	Energy Efficiency Total	52	49	48	50	53	59	57	55	54	51	46	44	42	40	37	33	33	32	30	29	527	892
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	465	-	-	465
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	15	15
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	45	-	-	15	-	-	-	30	-	-	90
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	-	-	-	120	-	-	135
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	720	318	353	359	-	-	199	227	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	997	955	968	425	735
	FOT West - Winter	104	101	107	75	75	-	-	-	-	38	-	-	-	-	-	-	-	-	-	-	50	25
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	125	307	199	227	4,041	156	650	740	258	618	2,412	613	248	773	82	93	72	2,458	1,699		
	Annual Additions, Short Term Resources	1,101	820	424	428	434	-	-	199	227	1,165	1,375	1,299	1,317	1,341	1,373	1,375	1,374	1,385	1,255	1,268		
	Total Annual Additions	1,231	945	732	628	660	4,041	156	849	966	1,423	1,993	3,712	1,930	1,588	2,145	1,457	1,468	1,457	3,713	2,967		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-26	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	370	-	185	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, UT	-	-	-	-	73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	73
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	73	1,920	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	1,993	3,093
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	227	-	-	-	-	-	-	500	-	-	-	-	-	-	-	227	727
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	898	11	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	904	-	-	-	-	-	-	500	-	100	-	-	-	898	11	1,127	2,636
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	-	8.3	-	5.1	-	138.3
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.1	-	-	2.1
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	7.0	12.0	27.6	94.0	44.6	328.7
	Energy Efficiency, ID	6	5	5	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	66	114
	Energy Efficiency, UT	58	61	66	68	69	66	67	65	62	62	57	56	52	50	51	36	32	25	22	26	642	1,049
	Energy Efficiency, WY	10	10	11	12	13	16	16	17	18	17	16	15	13	12	11	9	8	7	5	5	140	242
	Energy Efficiency Total	74	76	82	86	89	89	91	88	86	86	79	77	72	68	68	49	45	35	30	35	848	1,404
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150	-	150.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0	-	30.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	45.0	-	-	-	-	-	-	150.0	-	195.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	82	300	295	151	153	201	203	208	300	300	300	8	125
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind, Borah	-	-	-	-	-	-	-	-	218	-	-	-	-	-	-	-	-	-	-	-	218	218
	Total Wind	-	-	-	-	-	-	-	-	218	-	-	-	-	-	-	-	-	-	-	-	218	218
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - Borah	-	-	-	-	-	-	-	-	382	-	-	-	-	-	-	-	-	-	-	-	382	382
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	288	-	-	-	-	-	-	-	212	475	-	-	-	-	-	288	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Total Solar	-	-	-	-	-	1,047	-	-	382	-	359	-	-	212	475	-	-	-	-	702	1,428	3,177
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	32.3	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	57.2	53.5	-	120.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	36	34	39	43	41	39	37	34	32	31	30	27	26	24	26	24	24	381	660
	Energy Efficiency, WA	11	9	10	10	11	12	11	11	11	11	10	9	9	8	8	6	6	5	4	4	108	177
	Energy Efficiency Total	52	48	48	48	47	52	56	54	52	49	46	44	42	40	37	33	32	32	29	29	505	869
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	180	135	-	120	-	-	-	-	120	-	555
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	135	-	-	15	-	-	-	-	15	-	165
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	30	-	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	105
	FOT West - Summer	998	720	493	503	498	214	209	286	257	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	988	1,072	1,075	525	796
	FOT West - Winter	151	131	269	304	314	102	109	113	-	-	-	-	-	-	-	-	-	-	-	-	149	75
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	124	296	198	227	4,012	155	334	738	135	618	2,154	794	333	815	81	83	79	2,359	1,419		
	Annual Additions, Short Term Resources	1,149	851	762	807	812	316	318	398	257	1,157	1,375	1,370	1,226	1,228	1,276	1,278	1,284	1,288	1,372	1,375		
	Total Annual Additions	1,279	974	1,058	1,004	1,039	4,328	473	733	995	1,293	1,993	3,524	2,020	1,560	2,091	1,360	1,367	1,366	3,731	2,794		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-29	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	502	-	-	-	-	-	-	-	-	-	502
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	572	6	-	-	-	-	-	-	-	-	577
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	-	1,074	6	-	-	-	-	-	-	-	1,920	2,999
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	300	-	-	-	-	-	-	500	-	-	-	-	-	-	-	300	800
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	27	-	73	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	21	-	-	-	-	-	-	-	-	-	21
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	73	604	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	73	904	-	-	-	-	-	21	527	-	73	-	-	-	909	-	1,200	2,730
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	-	-	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.3	-	-	-	-	-	-	5.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68.5	-	-	5.7	-	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	-	-	-	-	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	-	2.1	-	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	18.7	-	-	-	-	-	-	-	-	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	142.1	8.2	1.8	13.8	117.1	-	15.3	11.4	3.2	21.6	44.6	379.1
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	4	3	3	69	118
	Energy Efficiency, UT	58	67	67	68	69	68	67	68	65	62	57	58	54	50	49	36	34	29	25	26	659	1,077
	Energy Efficiency, WY	10	10	11	14	15	16	17	18	18	18	16	15	13	12	11	9	8	7	5	6	148	251
	Energy Efficiency Total	74	83	85	88	92	92	92	93	90	87	80	79	74	68	65	49	47	40	33	35	876	1,445
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	645.0	780	-	1,425.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	120.0	-	-	-	-	-	-	-	390.0	-	-	510.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	180.0	-	-	-	-	-	-	105.0	105.0	-	390.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	108	272	300	300	231	300	300	300	300	300	300	11	151
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	Wind+Storage, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	5
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	5
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	425	-	-	-	-	-	405	830
	Total Solar	-	-	-	-	-	1,259	-	-	-	-	359	-	-	475	425	-	-	-	-	702	1,259	3,220
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	-	-	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	-	-	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20.3	-	-	-	3.0	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	5.4	-	-	-	30.3	-	-	-	-	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, OR-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.0	-	-	2.0
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	-	-	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	-	-	1.1	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	3.1	-	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	14.6	-	-	-	2.0	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	58.4	-	-	-	72.8	-	-	3.1	5.0	3.0	-	142.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	42	47	46	43	41	41	38	35	32	31	30	26	27	26	27	25	24	410	693
	Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	11	10	10	9	8	8	6	6	5	4	4	111	181
	Energy Efficiency Total	52	49	48	55	60	59	56	55	54	51	46	44	42	40	35	34	34	34	30	29	539	907
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	165	15	165	15	-	-	-	30	-	-	-	390
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	-	-	-	135
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	15	-	-	90
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	105	-	-	15	-	-	-	-	-	45	-	105	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	492	501	496	184	177	213	284	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	1,072	1,075	1,074	514	794
	FOT West - Winter	151	131	265	299	310	49	52	54	101	233	229	180	199	116	19	-	-	140	-	-	165	126
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	132	299	206	243	4,234	156	155	144	348	1,181	1,421	831	612	788	83	96	118	2,186	1,675		
	Annual Additions, Short Term Resources	1,149	850	757	800	806	232	230	267	385	1,415	1,576	1,555	1,574	1,422	1,394	1,375	1,374	1,511	1,375	1,374		
	Total Annual Additions	1,279	982	1,056	1,007	1,049	4,467	386	422	529	1,764	2,757	2,976	2,405	2,034	2,182	1,458	1,469	1,629	3,561	3,049		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-29PS	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	620
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	-	404	77	-	-	-	-	-	-	-	481
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	-	620	404	77	-	-	-	-	-	-	1,920	3,020
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	300	-	-	-	-	-	-	-	500	-	-	-	-	-	-	300	800
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	73	604	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	73	904	-	-	-	-	-	-	-	500	100	-	-	-	909	-	1,200	2,709
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	124.9	-	-	8.3	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	6.7	-	-	6.8	130.0	-	7.0	12.0	153.4	21.6	44.6	382.2
	Energy Efficiency, ID	6	5	6	7	7	7	7	7	7	7	7	6	6	6	6	5	4	3	3	3	67	116
	Energy Efficiency, UT	58	67	67	68	69	68	67	67	65	62	57	56	54	50	49	38	36	26	25	29	658	1,076
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	18	17	16	15	13	12	11	9	8	7	5	6	146	249
	Energy Efficiency Total	74	83	85	88	91	92	91	91	90	87	79	77	74	68	66	51	48	37	33	37	871	1,442
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	660	-	660.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	75.0	-	-	-	-	-	-	-	720.0	-	-	795.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	120.0	-	-	-	-	-	-	315.0	-	-	435.0
	Pump Storage - East	-	-	-	-	-	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	400	400
	FOT East - Summer	-	-	-	-	-	-	-	-	-	-	41	296	268	174	288	290	300	300	300	300	-	128
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	490	-	-	-	-	-	-	-	10	475	-	-	-	-	-	490	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Total Solar	-	-	-	-	-	1,249	-	-	-	-	359	-	-	10	475	-	-	-	-	702	1,249	2,795
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	2.0	-	37.7
	Demand Response, OR-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	61.4	-	-	61.4
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	1.1	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	3.1
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	166.2	3.0	-	178.6
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	33
	Energy Efficiency, OR	40	37	37	42	46	46	43	41	41	38	34	32	31	29	27	27	26	26	25	24	409	690
	Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	11	10	9	9	8	8	6	6	5	4	4	111	179
	Energy Efficiency Total	52	49	48	54	59	59	56	55	54	51	46	44	42	38	36	34	34	32	30	29	537	903
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	285	-	45	30	-	-	-	90	-	30	-	285	480
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	135	-	-	-	-	-	-	-	60	-	-	195
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	75	-	15	-	-	-	-	-	15	-	-	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	105	-	30	-	-	-	-	-	30	-	-	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	189	185	227	301	812	1,075	1,075	1,075	1,075	1,075	1,075	1,069	1,072	1,075	1,074	492	783
	FOT West - Winter	151	131	268	303	314	55	62	63	113	245	231	184	195	143	75	8	36	11	-	-	171	129
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	131	299	206	241	4,224	155	153	144	928	882	906	595	700	817	86	179	81	2,461	1,453		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	244	246	290	414	1,057	1,347	1,555	1,538	1,392	1,437	1,374	1,405	1,383	1,375	1,374		
	Total Annual Additions	1,279	982	1,060	1,012	1,053	4,468	401	444	558	1,985	2,229	2,461	2,133	2,092	2,254	1,459	1,584	1,464	3,836	2,827		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table 18 – Sensitivity Cases, Detailed Capacity Expansion Portfolio

		Capacity (MW)																				Resource Totals 1/	
	S-01	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	370	-	-	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, UT	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	70	1,920	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	1,990	3,090
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	230	-	-	-	-	-	-	-	500	-	-	-	-	-	-	230	730
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	899	10	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	155	62	-	683	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	155	62	-	913	-	-	-	-	-	-	-	500	100	-	-	-	899	10	1,130	2,639
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	3.7	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100.7	24.1	8.3	-	-	5.1	-	138.3
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	6.7	-	-	6.8	100.7	29.3	15.3	-	6.9	16.1	44.6	226.4
	Energy Efficiency, ID	6	5	5	6	7	7	7	7	7	7	6	6	6	6	5	4	4	3	3	3	64	111
	Energy Efficiency, UT	58	61	60	60	69	66	65	63	59	59	54	56	50	48	49	36	32	26	22	23	620	1,017
	Energy Efficiency, WY	10	10	11	12	13	15	16	17	17	16	15	14	13	12	11	9	8	7	5	5	137	237
	Energy Efficiency Total	74	76	77	78	89	88	88	86	83	82	76	76	69	65	65	49	45	37	30	32	821	1,365
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	165.0	-	-	165.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	225.0	-	-	225.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	-	-	126	258	13	300	296	300	300	300	300	-	110
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	221
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	221
	Wind, WallaW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	100
	Wind+Storage, PNC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	466	-	466
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	466	-	566
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	272	-	-	-	-	-	-	-	703	-	-	-	-	-	-	272	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Total Solar	-	-	-	-	-	1,031	-	-	-	-	359	-	-	703	-	-	-	-	-	702	1,031	2,795
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	1.9
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	5.8
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.2	-	9.2
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11.3	-	11.3
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	7.5	31.1	-	40.5
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	36	39	43	43	41	39	37	34	32	31	30	26	26	26	26	24	23	390	668
	Energy Efficiency, WA	11	9	10	10	11	12	11	11	11	11	10	9	9	8	8	7	6	5	4	4	108	177
	Energy Efficiency Total	52	48	48	48	52	56	56	54	52	49	46	44	42	40	35	33	33	32	29	28	515	877
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	120	-	30	-	-	-	-	-	-	-	150
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	30	-	-	45
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	15	-	30	-	-	-	-	105	-	-	150
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	105
	FOT West - Summer	434	166	337	346	341	70	46	50	97	654	959	1,075	1,075	1,075	1,075	1,075	1,066	1,075	1,073	967	254	653
	FOT West - Winter	60	56	156	191	202	-	2	8	57	193	124	87	96	23	-	-	-	-	120	-	92	69
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	124	287	188	230	4,008	152	147	135	131	488	2,120	111	1,376	301	113	93	84	2,472	1,506		
	Annual Additions, Short Term Resources	493	222	493	537	543	70	48	58	155	847	1,083	1,288	1,430	1,111	1,375	1,371	1,366	1,375	1,492	1,267		
	Total Annual Additions	623	345	780	724	773	4,077	201	205	290	978	1,571	3,408	1,540	2,486	1,675	1,484	1,459	1,459	3,965	2,773		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	S-02	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	389	-	-	-	195	-	-	-	-	-	-	584
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370	370
	Total SCCT	-	-	-	-	-	-	-	185	-	370	389	370	-	-	195	-	-	-	-	-	555	1,508
	Wind, OG	-	-	-	-	-	-	-	-	-	-	-	1,096	-	-	-	-	-	-	-	-	-	1,096
	Wind, UT	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75	75
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, OG	-	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	4
	Total Wind	-	-	-	-	75	1,920	-	-	-	-	-	1,096	4	-	-	-	-	-	-	-	1,995	3,095
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	225	-	-	-	-	-	500	-	-	-	-	-	-	-	-	225	725
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	164	66	-	670	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	164	66	-	995	-	-	-	-	-	500	-	-	-	-	-	-	909	-	1,225	2,634
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	-	-	7.0	-	165.4	21.6	161.2	382.2
	Energy Efficiency, ID	6	5	5	6	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	64	112
	Energy Efficiency, UT	58	61	60	60	69	66	65	63	62	59	54	54	52	50	51	36	32	26	23	23	623	1,024
	Energy Efficiency, WY	10	10	11	12	13	16	16	17	17	17	15	14	13	12	12	11	9	8	7	5	139	240
	Energy Efficiency Total	74	76	77	78	89	89	88	86	85	83	76	74	72	68	68	49	45	37	31	32	826	1,376
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	540	-	540.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0	45.0	-	75.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105.0	45.0	-	150.0
	FOT East - Summer	295	186	-	-	-	-	-	-	-	300	275	164	300	237	299	297	284	300	300	300	78	177
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind+Storage, YK	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	5	-	1	6
	Total Wind	-	-	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	5	-	1	6
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	404	-	-	-	-	-	-	-	-	-	-	-	-	425	-	404	829
	Total Solar	-	-	-	-	-	1,258	-	-	-	-	359	-	-	475	-	-	-	-	425	702	1,258	3,219
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8	4.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	-	3.1	-	5.2	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.3	-	-	5.3
	Demand Response Total	-	-	-	-	-	-	-	-	-	32.6	-	-	-	-	-	-	-	-	67.3	-	32.6	99.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	33
	Energy Efficiency, OR	40	37	50	49	47	46	45	43	39	37	34	32	31	30	27	26	26	26	24	23	431	710
	Energy Efficiency, WA	11	10	10	11	12	13	12	12	11	11	10	9	9	8	8	6	6	5	4	4	113	182
	Energy Efficiency Total	52	49	62	62	61	60	59	57	52	49	46	44	42	40	37	33	33	32	29	27	561	924
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	135	-	-	-	-	360	165	-	660
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	-	-	-	60	45	-	-	-	-	-	-	105
	Battery Storage - Portland NC	-	-	-	-	-	-	-	15	-	-	-	-	-	-	60	-	-	-	15	30	15	120
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	45	-	-	-	-	-	15	30	-	-	-	60	30	45	180
	Battery Storage - Yakima	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	1,276	1,125	922	966	1,001	405	505	831	912	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,071	1,074	1,074	1,075	902	988
	FOT West - Winter	37	234	372	408	421	157	162	165	215	349	285	249	252	216	168	93	110	90	-	-	252	199
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	125	318	206	235	4,322	155	500	137	652	877	2,092	118	805	434	82	85	69	2,645	1,637		
	Annual Additions, Short Term Resources	1,608	1,545	1,293	1,374	1,422	561	667	996	1,127	1,724	1,635	1,488	1,627	1,528	1,542	1,465	1,465	1,464	1,374	1,375		
	Total Annual Additions	1,738	1,669	1,611	1,580	1,657	4,884	823	1,497	1,264	2,376	2,512	3,580	1,745	2,333	1,975	1,547	1,550	1,533	4,018	3,012		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	S-03	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	185	-	185	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	185	-	-	-	185	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	185	185	-	185	185	-	-	-	-	-	185	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,070	-	-	-	-	-	-	-	-	-	1,070
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	-	1,070	30	-	-	-	-	-	-	-	1,920	3,020
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	300	-	-	-	-	-	-	-	500	-	-	-	-	-	-	300	800
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	52	-	5	-	-	-	-	-	-	56
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	907	2	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	73	604	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	73	904	-	-	-	-	-	-	52	500	5	-	-	-	907	2	1,200	2,665
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.3	-	5.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	8.3	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.1	37.3	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	-	-	7.0	8.3	105.4	70.3	161.2	379.1
	Energy Efficiency, ID	6	5	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	67	115
	Energy Efficiency, UT	58	66	67	68	69	66	67	65	65	62	54	56	52	50	51	36	32	25	22	26	652	1,056
	Energy Efficiency, WY	10	10	11	12	15	16	16	18	18	17	15	14	13	12	11	9	8	7	5	5	144	245
	Energy Efficiency Total	74	81	85	86	91	90	91	90	89	87	76	77	72	68	68	49	45	35	30	35	863	1,416
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285	-	285.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	240.0	-	240.0
	FOT East - Summer	133	-	-	-	-	-	-	-	-	300	263	267	300	245	300	294	297	300	300	300	43	165
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame SO	-	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	-	-	-	-	210
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	210	-	-	-	-	-	-	-	-	443	-	653
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	265	-	-	-	-	-	-	-	500	765
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	430	-	-	405	835
	Total Solar	-	-	-	-	-	1,259	-	-	-	-	359	-	265	-	-	-	-	430	-	702	1,259	3,015
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	2.0	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	1.1	-	6.6
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	-	93.1	3.0	9.4	105.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	43	49	47	46	44	43	41	38	34	32	31	30	27	26	24	26	24	24	427	705
	Energy Efficiency, WA	11	10	10	11	12	13	12	12	11	11	10	9	9	8	8	6	6	5	4	4	113	183
	Energy Efficiency Total	52	49	55	62	61	60	58	57	54	51	46	44	42	40	37	33	32	32	29	29	558	921
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	120	105	225
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	45	45
	Battery Storage - Portland NC	-	-	-	-	-	-	-	45	-	30	-	-	-	-	30	-	-	-	-	15	75	120
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	30	-	15	-	-	-	30	60	-	-	-	-	45	45	180
	Battery Storage - Yakima	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	1,125	984	584	618	626	219	197	484	561	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	970	1,075	1,075	647	856
	FOT West - Winter	526	498	630	661	672	404	962	969	1,016	591	380	327	921	896	849	772	781	108	386	315	693	633
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	130	314	212	234	4,233	158	518	143	459	883	1,383	461	835	384	82	83	505	1,670	2,003		
	Annual Additions, Short Term Resources	1,784	1,482	1,214	1,279	1,298	623	1,159	1,454	1,576	1,966	1,717	1,669	2,296	2,216	2,224	2,141	2,153	1,378	1,761	1,690		
	Total Annual Additions	1,914	1,612	1,528	1,490	1,532	4,856	1,317	1,972	1,719	2,425	2,600	3,052	2,756	3,051	2,608	2,222	2,236	1,882	3,430	3,693		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

		Capacity (MW)																				Resource Totals 1/	
	S-04	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	185	185	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	185	740	-	-	-	-	-	-	-	-	-	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,058	-	-	-	-	-	-	-	-	-	1,058
	Wind, UT	-	-	-	-	20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	20
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	22	-	-	-	-	-	-	-	22
	Total Wind	-	-	-	-	20	1,920	-	-	-	-	-	1,058	-	22	-	-	-	-	-	-	1,940	3,021
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	280	-	-	-	-	-	-	-	500	-	-	-	-	-	-	280	780
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	-	-	-	-	-	-	20
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	160	64	53	623	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	160	64	53	903	-	-	-	-	-	20	-	500	100	-	-	-	909	-	1,180	2,709
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	2.6
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	3.7	-	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	2.6
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	11.0	105.6	8.2	-	-	-	-	8.3	-	-	5.1	11.0	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	37.3
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	11.0	112.3	8.2	-	6.8	5.2	-	15.3	3.7	23.7	73.3	55.6	304.1
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	68	116
	Energy Efficiency, UT	58	67	67	68	69	68	67	68	65	62	54	56	52	50	51	36	32	25	22	26	659	1,063
	Energy Efficiency, WY	10	10	11	14	15	16	17	18	18	18	15	14	13	12	11	9	8	7	5	5	148	249
	Energy Efficiency Total	74	83	85	88	91	92	92	93	90	87	76	76	72	68	68	49	45	35	30	35	875	1,428
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0	-	-	-	-	210	-	240.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30.0	-	-	-	-	-	-	30.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	150.0	-	-	-	-	90.0	-	240.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	220	287	300	297	140	204	265	300	300	300	300	22	146
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	664	221	-	886
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	664	221	-	886
	Wind+Storage, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-	-	25
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25	-	-	25
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	405	-	-	405	810
	Total Solar	-	-	-	-	-	1,259	-	-	-	-	359	-	-	475	-	-	-	405	-	702	1,259	3,200
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.0	-	2.0
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	4.1	-	-	-	-	-	-	-	9.2	-	-	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	1.1
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	-	-	8.3
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	13.4	-	-	-	-	-	8.3	-	14.0	3.0	-	38.7
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	37	39	46	43	41	39	37	33	31	31	30	27	26	24	25	22	23	395	666
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	11	10	9	9	8	8	6	6	5	4	4	110	177
	Energy Efficiency Total	52	49	48	50	53	59	56	54	52	49	44	42	42	40	37	32	31	30	27	27	522	875
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	75	-	-	15	-	-	-	-	-	-	-	75	90
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	30	-	-	60	-	-	-	-	-	-	-	30	90
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	15	-	-	-	-	45	-	-	-	-	-	15	60
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	105
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	996	753	473	488	484	182	161	317	397	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,019	1,069	1,075	533	801
	FOT West - Winter	151	131	265	300	311	48	54	56	103	235	223	174	186	117	67	5	28	-	-	-	166	123
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	132	299	202	235	4,233	156	154	142	372	791	1,944	293	1,112	465	82	100	474	2,199	1,361		
	Annual Additions, Short Term Resources	1,147	884	739	788	795	229	216	374	500	1,531	1,585	1,549	1,558	1,331	1,346	1,345	1,403	1,319	1,369	1,375		
	Total Annual Additions	1,277	1,016	1,038	990	1,030	4,463	372	528	642	1,903	2,375	3,493	1,851	2,443	1,810	1,426	1,503	1,793	3,567	2,736		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	S-05	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	370	-	-	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	994	-	-	-	-	-	-	-	-	-	994
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	30	-	76	-	-	-	-	-	-	-	106
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	-	1,024	-	76	-	-	-	-	-	-	1,920	3,020
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	300	-	-	-	-	-	-	500	-	-	-	-	-	-	-	300	800
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	904	5	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	73	604	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	73	904	-	-	-	-	-	-	500	-	100	-	-	-	904	5	1,200	2,709
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48.4	-	48.4
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	92.5	32.4	-	-	-	-	-	-	8.3	5.1	-	138.3
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.1	-	2.1
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19.9	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	99.2	32.4	-	12.0	-	-	7.0	-	15.2	90.0	44.6	300.4
	Energy Efficiency, ID	6	5	6	7	7	7	7	7	7	7	7	6	6	6	6	4	4	3	3	3	67	116
	Energy Efficiency, UT	58	67	67	68	69	66	67	65	65	62	57	58	52	50	51	36	32	26	23	26	654	1,065
	Energy Efficiency, WY	10	10	11	12	15	16	16	18	18	17	16	15	13	12	11	9	8	7	5	5	144	246
	Energy Efficiency Total	74	83	85	86	91	90	91	90	89	87	80	79	72	68	68	49	45	37	31	35	865	1,427
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420	-	420.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	90.0	-	45.0	-	-	-	-	-	30.0	-	165.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	31	224	300	280	145	300	281	300	300	300	300	3	138
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Total Solar	-	-	-	-	-	1,259	-	-	-	-	359	-	-	475	-	-	-	-	-	702	1,259	2,795
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.4	-	7.4
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.3	-	5.3
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	1.9	-	7.5	-	-	-	-	21.6	15.7	-	46.7
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	33
	Energy Efficiency, OR	40	37	37	40	39	46	43	41	39	38	35	32	31	30	28	26	26	26	25	24	399	682
	Energy Efficiency, WA	11	9	10	11	12	12	12	11	11	11	10	9	9	8	8	6	6	5	4	4	109	179
	Energy Efficiency Total	52	48	48	52	53	59	56	54	52	51	46	44	42	40	38	33	33	32	30	29	525	893
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	15	-	120	-	-	150	-	-	-	60	-	15	345
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	75
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	45	-	-	30	-	-	-	-	-	-	75
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	120	-	-	-	-	15	-	-	-	60	-	120	195
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	720	494	504	500	175	169	198	243	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,051	1,063	1,075	1,062	507	789
	FOT West - Winter	151	131	268	303	314	50	57	60	110	242	262	226	247	128	75	7	22	175	-	-	169	141
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	130	299	202	233	4,232	155	151	141	378	585	2,066	614	724	401	82	85	69	2,440	1,341		
	Annual Additions, Short Term Resources	1,149	850	762	807	814	225	225	258	353	1,347	1,561	1,601	1,603	1,347	1,450	1,363	1,374	1,538	1,375	1,362		
	Total Annual Additions	1,279	981	1,061	1,009	1,049	4,457	380	409	495	1,725	2,146	3,667	2,216	2,071	1,851	1,445	1,459	1,607	3,815	2,703		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	S-06	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	185	370	-	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	185	370	-	-	-	-	-	-	-	370	-	185	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	1,920	3,020
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	300	-	-	-	-	-	-	500	-	-	-	-	-	-	-	300	800
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	73	604	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	73	904	-	-	-	-	-	-	500	-	100	-	-	-	909	-	1,200	2,709
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	-	8.2	-	-	-	8.3	-	-	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	116.7	6.7	-	8.2	12.0	-	-	15.3	3.7	25.5	141.2	161.2	373.9
	Energy Efficiency, ID	7	7	7	7	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	70	118
	Energy Efficiency, UT	66	64	67	68	69	68	67	68	65	62	57	56	50	48	49	36	32	25	22	26	664	1,064
	Energy Efficiency, WY	11	11	11	14	15	16	16	18	18	17	16	15	13	12	11	9	8	7	5	5	149	249
	Energy Efficiency Total	84	82	85	88	91	92	91	93	90	87	79	77	69	65	65	49	45	35	30	34	883	1,431
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	225	-	225.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	105.0	-	45.0	-	-	-	-	-	45.0	-	195.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	282	263	194	206	252	300	2	88	88	300	300	28	114
	FOT East - Winter	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300	300	-	-	-	45
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind, WallaW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	58	-	58
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	92	-	-	92
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	92	58	-	150
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	455	-	-	-	-	-	-	-	45	475	-	-	-	-	-	455	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	338	-	405	743
	Total Solar	-	-	-	-	-	1,214	-	-	-	-	359	-	-	45	475	-	-	-	338	702	1,214	3,133
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	32.3	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	-	57.2	53.5	9.4	120.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	32
	Energy Efficiency, OR	40	41	32	42	47	46	43	41	40	38	33	32	30	29	26	26	24	26	24	24	410	682
	Energy Efficiency, WA	10	9	10	11	12	12	12	12	11	11	10	9	9	8	8	6	6	5	4	4	109	177
	Energy Efficiency Total	52	52	44	54	60	59	56	55	53	51	45	43	40	38	35	33	32	32	29	29	537	891
	Battery Storage - S-Oregon	-	-	15	-	-	-	-	-	-	45	-	105	-	15	180	-	-	(15)	-	-	60	345
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	15	75	-	-	-	-	-	-	-	-	-	90
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	75	-	15	-	-	-	-	-	-	-	90
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	60	-	-	-	90	15	-	-	-	-	-	60	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	1,010	964	521	555	560	191	187	472	545	1,075	1,075	1,075	1,075	1,075	1,075	1,075	989	998	1,075	1,070	608	833
	FOT West - Winter	149	123	259	294	305	53	60	62	111	243	219	172	188	136	67	-	34	5	-	-	166	124
	Existing Plant Retirements/Conversions	-	(308)	(186)	(224)	(1)	(412)	(387)	(505)	(85)	(912)	(449)	(149)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	139	134	319	206	234	4,189	155	155	144	659	875	1,580	617	326	870	81	92	55	2,798	1,302		
	Annual Additions, Short Term Resources	1,159	1,088	780	849	865	245	247	533	657	1,600	1,558	1,441	1,469	1,463	1,442	1,377	1,411	1,391	1,375	1,370		
	Total Annual Additions	1,299	1,222	1,099	1,055	1,099	4,433	402	688	800	2,259	2,432	3,022	2,087	1,788	2,312	1,459	1,503	1,447	4,173	2,672		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	S-07	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	370	-	-	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	947	-	-	-	-	-	-	-	-	-	947
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	66	-	83	-	-	-	-	-	-	-	149
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	-	1,013	-	83	-	-	-	-	-	-	1,920	3,016
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	300	-	-	-	-	-	500	-	-	-	-	-	-	-	-	300	800
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	4
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	900	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	-	-	-	1,200	-	-	-	-	-	504	-	-	-	-	-	-	909	-	1,200	2,613
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	8.3	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	8.3	9.9	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	3.7	23.7	143.1	44.6	373.9
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	68	116
	Energy Efficiency, UT	58	67	67	68	69	66	67	65	65	62	57	58	53	50	48	36	32	25	22	26	654	1,060
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	18	18	16	15	13	12	11	9	8	7	5	5	147	248
	Energy Efficiency Total	74	83	85	88	91	90	91	90	90	87	79	79	73	68	64	49	45	35	30	35	869	1,425
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	270	-	270.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	-	-	-	-	-	-	15.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	120.0	75.0	-	-	-	-	-	-	-	195.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	46	263	300	277	300	230	232	300	300	300	300	5	142
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	221	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	221	-	443
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Total Solar	-	-	-	-	-	1,259	-	-	-	-	359	-	-	-	475	-	-	-	-	702	1,259	2,795
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.4	32.3	-	37.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	57.2	44.3	-	110.9
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	42	39	45	43	41	39	37	33	32	31	29	26	26	24	26	24	24	398	673
	Energy Efficiency, WA	11	9	10	11	12	12	12	11	11	11	10	9	9	8	8	6	6	5	4	4	109	177
	Energy Efficiency Total	52	48	48	54	53	58	56	54	52	49	45	43	42	38	35	33	32	32	29	29	524	882
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	45	-	90	45	-	270	-	-	-	-	-	45	450
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	15	-	60	15	30	-	-	-	-	-	-	15	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	30	-	15	-	15	15	-	-	-	-	-	30	75
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	15	-	45	-	-	105	-	-	-	-	-	15	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	54	49	147	221	1,075	1,075	1,075	1,075	1,075	1,074	1,075	1,006	1,016	1,065	1,059	476	768
	FOT West - Winter	151	131	268	303	314	32	39	40	90	222	212	166	185	123	54	-	29	-	-	-	159	118
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	131	140	150	154	4,527	155	151	142	346	617	2,412	295	337	964	82	92	70	2,575	1,444		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	86	88	188	311	1,342	1,551	1,541	1,537	1,498	1,357	1,307	1,335	1,316	1,365	1,359		
	Total Annual Additions	1,279	982	901	956	966	4,613	243	339	453	1,689	2,167	3,953	1,832	1,834	2,321	1,389	1,427	1,386	3,940	2,803		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	S-08	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	185	185	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	555	-	-	-	-	-	-	185	185	-	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	1,920	3,020
	Utility Solar+Storage - PV - Utah-S	-	-	206	90	4	-	-	29	233	216	-	22	-	-	-	-	-	-	-	-	778	800
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	69	831	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	206	90	72	931	-	29	233	216	-	22	-	-	-	-	-	-	909	-	1,778	2,709
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	3.7	-	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	124.9	-	-	-	-	-	8.3	-	5.1	-	138.3
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	39.4
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.2	-	1.2
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	6.7	124.9	-	6.8	5.2	-	7.0	12.0	3.2	135.2	44.6	345.5
	Energy Efficiency, ID	6	5	5	6	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	66	114
	Energy Efficiency, UT	58	61	67	68	69	66	67	65	62	62	57	56	54	52	47	36	32	25	22	26	644	1,051
	Energy Efficiency, WY	10	10	11	12	15	16	16	17	18	17	16	15	13	12	11	9	8	7	5	5	142	244
	Energy Efficiency Total	74	76	84	86	91	90	91	88	86	86	79	77	74	70	64	49	45	35	30	35	852	1,409
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	270	-	270.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	105.0	15.0	15.0	-	-	-	-	45.0	-	180.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	-	235	300	277	215	265	268	300	300	300	300	-	138
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	14
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	14
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	475	-	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	416	-	-	405	821
	Total Solar	-	-	-	-	-	1,259	-	-	-	-	359	-	-	475	-	-	-	416	-	702	1,259	3,211
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32.3	-	32.3
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.3	-	-	9.3
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	17.6	32.3	-	59.3
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	17	32
	Energy Efficiency, OR	40	37	37	36	39	46	43	41	41	38	35	32	31	31	26	26	24	25	24	24	397	674
	Energy Efficiency, WA	11	9	10	10	11	12	11	12	11	11	10	10	9	8	8	6	6	5	4	4	109	178
	Energy Efficiency Total	52	48	48	48	52	59	56	55	54	51	46	44	42	42	35	33	32	31	29	29	522	884
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	30	-	165	75	-	150	-	-	-	-	-	30	420
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	105
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	15	-	-	90	-	-	-	-	-	-	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	15	-	-	-	-	135	-	-	-	-	-	15	150
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	111	107	165	159	1,005	1,075	1,075	1,075	1,075	1,074	1,075	1,048	944	1,075	1,072	476	767
	FOT West - Winter	151	131	268	303	314	39	45	47	96	228	222	172	192	110	61	-	36	-	-	-	162	121
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	124	345	223	234	4,259	155	179	373	504	492	2,217	296	609	494	81	83	507	2,121	1,447		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	150	152	212	255	1,234	1,532	1,547	1,544	1,400	1,400	1,343	1,384	1,244	1,375	1,372		
	Total Annual Additions	1,279	974	1,107	1,029	1,046	4,409	307	390	628	1,737	2,024	3,764	1,840	2,009	1,893	1,424	1,467	1,752	3,496	2,820		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.19 – DSM Bundled Cases, Detailed Capacity Expansion Portfolio

		Capacity (MW)																				Resource Totals 1/	
	P-45DP	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	370	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, CO	-	-	-	-	-	-	-	-	-	-	-	1,088	-	-	-	-	-	-	-	-	-	1,088
	Wind, UT	-	-	-	-	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	64	64
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	64	1,920	-	-	-	-	620	1,088	-	-	-	-	-	-	-	-	1,984	3,691
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	236	-	-	-	-	-	-	-	-	-	500	-	-	-	-	236	736
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - CO	-	-	-	-	-	-	-	-	-	-	-	-	12	-	-	-	-	-	-	-	-	12
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	9	668	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	9	904	-	-	-	-	-	-	12	-	100	500	-	-	909	-	1,136	2,658
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	6.8	5.2	-	15.3	-	157.1	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	7	8	8	8	8	8	8	8	8	7	7	7	6	5	4	4	4	3	76	130
	Energy Efficiency, UT	58	76	77	77	79	78	79	77	74	71	70	64	62	62	53	38	34	28	26	28	745	1,210
	Energy Efficiency, WY	10	11	12	13	16	17	17	18	18	17	16	15	14	12	11	9	8	7	5	5	149	251
	Energy Efficiency Total	74	93	96	98	103	103	104	103	99	96	94	87	83	81	70	52	47	39	35	36	970	1,592
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135.0	360	-	495.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	75.0	-	-	-	-	-	-	-	-	240.0	-	315.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	90.0	105.0	-	-	-	-	15.0	135.0	-	345.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	173	293	220	196	249	297	182	281	300	300	300	17	139
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	454	-	-	-	-	-	-	-	46	475	-	-	-	-	-	454	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	430	405	835
	Total Solar	-	-	-	-	-	1,213	-	-	-	-	359	-	-	46	475	-	-	-	-	1,132	1,213	3,225
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	107.7	-	-	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	20	37
	Energy Efficiency, OR	40	35	36	36	38	44	42	41	39	39	35	35	35	34	27	27	26	28	26	25	388	685
	Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	11	10	10	9	9	8	6	6	5	4	4	111	184
	Energy Efficiency Total	52	46	48	48	51	59	56	55	52	52	48	47	47	45	37	35	34	34	32	30	518	906
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	45	120	-	-	-	-	-	-	-	60	-	45	225
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	30	45	-	30	-	-	-	-	-	-	-	30	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	105	-	-	15	-	-	-	-	45	-	-	165
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	725	500	515	516	198	199	270	347	1,075	1,075	1,075	1,075	1,075	1,075	1,075	979	976	1,074	1,075	534	795
	FOT West - Winter	151	135	276	318	336	89	102	112	167	304	272	237	248	198	146	66	86	73	-	-	199	166
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	139	310	210	245	4,199	169	350	152	328	1,704	1,599	262	299	687	587	96	73	2,308	1,955		
	Annual Additions, Short Term Resources	1,149	861	776	833	852	287	301	382	514	1,552	1,640	1,532	1,518	1,522	1,518	1,322	1,346	1,350	1,374	1,375		
	Total Annual Additions	1,279	1,000	1,086	1,043	1,097	4,486	470	732	665	1,880	3,343	3,131	1,780	1,821	2,204	1,910	1,442	1,422	3,682	3,330		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-46DP	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	370	-	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	923	-	-	-	-	-	-	-	-	-	923
	Wind, UT	-	-	-	-	300	-	-	-	-	-	-	-	4	4	23	-	-	-	-	-	300	331
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	300	1,920	-	-	-	620	-	923	4	4	23	-	-	-	-	-	2,840	3,793
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	469	-	-	-	-	-	-	-	-	469
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	49	129	-	-	-	-	-	-	-	-	178
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	677	-	-	-	-	-	49	598	-	100	-	-	-	909	-	900	2,556
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	21.6	161.2	382.2
	Energy Efficiency, ID	6	7	7	7	8	8	8	8	8	8	7	7	7	7	6	5	5	4	3	3	77	130
	Energy Efficiency, UT	58	74	77	77	79	79	77	77	73	70	63	62	58	54	53	39	35	27	23	26	741	1,181
	Energy Efficiency, WY	10	11	12	13	14	17	17	18	18	17	15	15	13	12	11	9	8	7	5	5	146	245
	Energy Efficiency Total	74	91	96	98	102	104	103	103	100	95	86	83	78	73	70	52	48	37	31	34	964	1,556
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	-	15.0	-	-	-	-	-	-	-	-	-	-	15
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420.0	90	-	510.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0	30.0	-	-	60.0	-	300.0	-	-	420.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	15.0	105.0	-	-	60.0	-	75.0	45.0	-	300.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	227	171	254	87	148	255	261	275	300	300	300	23	129
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	-	-	(349)	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	-	-	-	-	-	-	(353)	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	206	-	-	206
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	206	-	-	206
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	713	-	-	349	-	-	-	353	-	-	-	-	-	713	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	224	-	405	629
	Total Solar	-	-	-	-	-	905	-	713	-	-	349	-	-	-	828	-	-	-	224	-	1,618	3,019
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	5.3	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	40.4	-	-	-	5.3	-	-	-	62.0	-	9.4	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	20	37
	Energy Efficiency, OR	40	35	37	42	45	45	42	41	39	37	35	33	32	31	27	27	26	26	23	24	403	687
	Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	11	10	10	9	9	8	6	6	5	4	4	111	184
	Energy Efficiency Total	52	46	49	55	59	59	57	55	53	50	47	45	43	42	37	35	34	32	29	29	535	907
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	15	120	15	-	-	-	-	-	-	-	60	-	135	210
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	75	75
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	45	-	15	-	-	-	-	-	45	-	15	-	45	120
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	15	-	-	60	-	-	15	-	-	-	-	60	30	15	180
	Battery Storage - Yakima	-	-	-	-	-	-	-	90	15	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	724	500	515	515	106	106	516	589	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,070	1,062	1,075	1,075	565	819
	FOT West - Winter	151	135	276	318	336	64	77	81	133	270	264	228	240	180	135	68	86	74	-	-	184	156
	Existing Plant Retirements/Conversions	-	(61)	(373)	(224)	(1)	(62)	-	(1,207)	(85)	(912)	(444)	(396)	(350)	(114)	(913)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	137	310	216	479	3,665	167	1,168	227	1,087	1,018	1,478	753	281	1,065	87	697	70	2,555	250		
	Annual Additions, Short Term Resources	1,149	859	776	833	851	171	183	598	723	1,572	1,509	1,557	1,402	1,403	1,465	1,405	1,431	1,436	1,375	1,375		
	Total Annual Additions	1,279	996	1,087	1,049	1,330	3,836	350	1,765	950	2,659	2,528	3,035	2,155	1,684	2,530	1,492	2,128	1,506	3,929	1,625		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-53DP	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	370	370	-	-	-	-	-	-	-	-	185	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620	620
	Wind, CO	-	-	-	-	-	-	-	-	-	-	-	923	-	-	-	-	-	-	-	-	-	923
	Wind, UT	-	-	-	-	300	-	-	-	-	-	-	-	4	4	23	-	-	-	-	-	300	331
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	300	1,920	-	-	-	620	-	923	4	4	23	-	-	-	-	-	2,840	3,793
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	469	-	-	-	-	-	-	-	-	469
	Utility Solar+Storage - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	49	129	-	-	-	-	-	-	-	-	178
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	-	677	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	-	677	-	-	-	-	-	49	598	-	100	-	-	-	909	-	900	2,556
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	116.7	-	8.2	-	-	-	-	-	-	8.3	5.1	116.7	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	-	-	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	116.7	6.7	8.2	-	12.0	1.8	-	7.0	-	163.7	21.6	161.2	382.2
	Energy Efficiency, ID	6	7	7	7	8	8	8	8	8	8	7	7	7	7	6	5	5	4	3	3	77	130
	Energy Efficiency, UT	58	74	77	77	79	79	77	77	73	70	63	62	58	54	53	39	35	27	23	26	741	1,181
	Energy Efficiency, WY	10	11	12	13	14	17	17	18	18	17	15	15	13	12	11	9	8	7	5	5	146	245
	Energy Efficiency Total	74	91	96	98	102	104	103	103	100	95	86	83	78	73	70	52	48	37	31	34	964	1,556
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	-	15.0	-	-	-	-	-	-	-	-	-	-	15
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	420.0	90	-	510.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0	30.0	-	-	60.0	-	300.0	-	-	420.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	15.0	105.0	-	-	60.0	-	75.0	45.0	-	300.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	227	171	254	87	148	255	261	275	300	300	300	23	129
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	-	-	(356)	(356)
	JimBridger 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(349)	-	-	-	-	-	-	-	-	-	-	(349)
	JimBridger 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	-	-	-	-	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	-	-	443
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	206	-	-	206
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	206	-	-	206
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	713	-	-	349	-	-	-	353	-	-	-	-	-	713	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	224	-	405	629
	Total Solar	-	-	-	-	-	905	-	713	-	-	349	-	-	-	828	-	-	-	224	-	1,618	3,019
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	-	-	-	-	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	5.8	-	-	-	-	-	-	-	-	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	-	-	3.0
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	13.3	-	-	-	-	-	-	-	-	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	11.3	-	-	-	5.3	-	-	-	-	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	9.4	40.4	-	-	-	5.3	-	-	-	62.0	-	9.4	117.1
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	20	37
	Energy Efficiency, OR	40	35	37	42	45	45	42	41	39	37	35	33	32	31	27	27	26	26	23	24	403	687
	Energy Efficiency, WA	11	10	10	11	12	12	12	12	11	11	10	10	9	9	8	6	6	5	4	4	111	184
	Energy Efficiency Total	52	46	49	55	59	59	57	55	53	50	47	45	43	42	37	35	34	32	29	29	535	907
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	15	120	15	-	-	-	-	-	-	-	60	-	135	210
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	75	75
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	45	-	15	-	-	-	-	-	45	-	15	-	45	120
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	15	-	-	60	-	-	15	-	-	-	-	60	30	15	180
	Battery Storage - Yakima	-	-	-	-	-	-	-	90	15	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	724	500	515	515	106	106	516	589	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,070	1,062	1,075	1,075	565	819
	FOT West - Winter	151	135	276	318	336	64	77	81	133	270	264	228	240	180	135	68	86	74	-	-	184	156
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(62)	-	(1,212)	(85)	(912)	(442)	(396)	(350)	(114)	(911)	(156)	(36)	(280)	(2,260)	(43)		
	Annual Additions, Long Term Resources	130	137	310	216	479	3,665	167	1,168	227	1,087	1,018	1,478	753	281	1,065	87	697	70	2,555	250		
	Annual Additions, Short Term Resources	1,149	859	776	833	851	171	183	598	723	1,572	1,509	1,557	1,402	1,403	1,465	1,405	1,431	1,436	1,375	1,375		
	Total Annual Additions	1,279	996	1,087	1,049	1,330	3,836	350	1,765	950	2,659	2,528	3,035	2,155	1,684	2,530	1,492	2,128	1,506	3,929	1,625		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

Table K.21 – P70 Cases, Detailed Capacity Expansion Portfolio

		Capacity (MW)																				Resource Totals 1/	
	P-70	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	185	-	-	370	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	185	-	-	370	-	-	-	370	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	119	501	-	-	-	-	-	-	-	-	-	119	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,083	-	-	-	-	-	-	-	-	-	1,083
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	119	501	1,083	-	-	-	-	-	-	-	-	2,039	3,623
	Utility Solar - PV - Utah-S	-	-	146	59	67	7	-	-	-	-	-	-	-	-	-	-	-	400	-	-	279	679
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	21	-	-	-	-	-	-	500	-	-	-	-	-	-	-	21	521
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	17	-	-	-	-	-	-	-	-	-	17
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	37	3	703	-	-	-	-	-	-	-	-	37	743
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	157	-	-	-	-	-	-	-	-	-	-	-	-	-	-	157	157
	Total Solar	-	-	146	59	67	285	-	-	-	37	3	720	500	-	-	-	-	400	-	909	594	3,126
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	124.9	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	-	6.7	124.9	-	12.0	-	-	15.3	-	157.1	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	7	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	70	118
	Energy Efficiency, UT	58	67	69	73	75	66	67	68	65	62	54	53	52	50	49	36	33	26	23	26	670	1,072
	Energy Efficiency, WY	10	12	13	16	18	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	155	256
	Energy Efficiency Total	74	85	88	96	100	90	91	93	91	87	76	74	71	68	65	49	45	37	31	35	896	1,447
	Battery Storage - Utah-N	-	-	-	-	150.0	-	-	-	-	-	-	-	-	-	-	-	-	-	120	555	150	825
	Battery Storage - WYSW	-	-	-	-	15.0	-	-	-	-	525.0	-	-	-	-	-	-	-	-	-	-	540.0	540.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285.0	90.0	-	375.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	256	219	300	252	254	298	300	88	300	300	300	26	143
	FOT East - Winter	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	-	-	-	-	15
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	SCCT Frame YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	233	-	-	233
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	676	-	-	676
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	337	-	-	-	-	-	-	500	837
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	183	-	-	-	405	588
	Utility Solar - PV - jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	270	-	270
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,142	-	1,142
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	138	-	-	-	-	-	-	-	138
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14	-	-	-	-	14
	Total Solar	-	-	-	-	-	905	-	-	-	-	-	-	-	475	100	-	197	-	-	1,412	905	3,089
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	-	-	-	9.2	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.1	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	9.4	-	-	9.2	-	-	-	118.8	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	19	34
	Energy Efficiency, OR	40	43	43	49	47	39	41	41	39	37	33	31	30	29	26	27	26	26	24	24	417	691
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	10	9	9	8	8	8	6	6	5	4	4	112	180
	Energy Efficiency Total	52	56	56	63	61	52	55	54	52	49	44	41	40	38	35	34	33	32	29	29	549	904
	Battery Storage - S-Oregon	-	-	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	150	180
	Battery Storage - Willamette Valley	-	-	-	-	15	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	60	60
	Battery Storage - Portland NC	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	15	60	60	135
	Battery Storage - Walla Walla	-	-	-	-	30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	165	30	195
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	959	617	676	1,052	469	562	537	595	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,051	1,075	979	1,029	754	906
	FOT West - Winter	151	131	268	303	314	245	251	253	303	315	308	334	301	331	284	201	184	180	-	-	253	233
	Existing Plant Retirements/Conversions	-	(308)	(573)	(224)	(352)	(62)	-	(148)	(3)	(764)	(93)	(506)	(350)	(114)	(557)	(156)	(117)	(280)	(2,260)	(1,101)		
	Annual Additions, Long Term Resources	130	141	306	217	763	3,252	154	155	142	861	631	2,237	611	593	579	83	291	469	1,802	3,306		
	Annual Additions, Short Term Resources	1,149	1,090	886	979	1,366	714	813	790	898	1,645	1,602	1,709	1,628	1,661	1,657	1,576	1,623	1,555	1,279	1,329		
	Total Annual Additions	1,279	1,231	1,192	1,197	2,129	3,966	967	944	1,040	2,507	2,233	3,946	2,239	2,254	2,236	1,660	1,914	2,024	3,081	4,635		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-71	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	185	-	-	-	-	-	-	185
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	185	-	-	-	370	-	-	555
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,077	23	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,077	23	-	-	-	-	-	-	-	1,920	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	-	-	-	-	-	-	-	-	-	-	-	-	-	400	-	-	205	605
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	95	-	-	-	-	-	-	-	500	-	-	-	-	-	-	95	595
	Utility Solar - PV - Naughton	-	-	-	-	156	156	-	-	-	-	-	-	-	-	-	-	-	-	-	-	312	312
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	-	862	-	-	-	-	-	-	-	-	-	862
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	38	-	-	-	-	-	-	-	-	-	-	-	-	-	-	38	38
	Total Solar	-	-	146	59	156	389	-	-	-	-	-	862	-	500	-	-	-	400	-	909	750	3,421
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	124.9	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	-	6.7	-	-	6.8	130.0	-	15.3	-	157.1	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	70	117
	Energy Efficiency, UT	58	67	69	73	75	68	71	68	65	67	54	53	50	50	49	36	32	26	22	26	681	1,079
	Energy Efficiency, WY	10	12	13	14	18	16	18	19	19	18	15	14	13	12	11	9	8	7	5	5	156	256
	Energy Efficiency Total	74	85	88	94	100	92	96	94	91	92	75	74	69	68	66	49	45	37	30	35	906	1,453
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	330.0	-	-	-	-	-	-	-	-	255	525	330	1,110
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	255.0	-	-	-	-	-	-	-	-	-	120.0	255.0	375.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285.0	285.0	-	570.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	95	42	226	300	180	223	225	300	300	300	300	9	125
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	-	(351)
	JimBridger 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	94	-	-	-	-	-	-	500	594
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	345	-	405	750
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,408	-	1,408
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	143	238	-	-	-	-	-	-	381
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	85
	Total Solar	-	-	-	-	-	905	-	-	-	-	-	-	-	237	338	-	-	-	430	1,408	905	3,318
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.3	-	-	-	3.9	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	3.1	-	-	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.9	-	3.1	-	110.4	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	19	34
	Energy Efficiency, OR	40	43	43	46	47	39	43	41	39	37	33	31	30	29	26	27	26	26	24	24	416	689
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	11	9	9	8	8	8	6	6	5	4	4	113	180
	Energy Efficiency Total	52	56	56	59	61	53	56	54	52	49	44	41	40	38	35	34	33	32	29	29	547	903
	Battery Storage - S-Oregon	-	-	-	-	105	-	-	-	-	30	-	-	-	-	-	-	-	-	-	165	135	300
	Battery Storage - Willamette Valley	-	-	-	-	60	-	-	-	-	15	-	-	-	-	-	-	-	-	-	-	75	75
	Battery Storage - Portland NC	-	-	-	-	45	-	-	-	-	30	-	-	-	-	-	-	-	-	15	75	75	165
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	120	-	-	-	-	-	-	-	-	-	45	120	165
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	959	617	677	858	284	377	353	412	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,010	1,046	1,075	661	863
	FOT West - Winter	151	131	268	303	314	243	249	253	303	317	309	336	302	294	241	185	120	119	-	-	253	222
	Existing Plant Retirements/Conversions	-	(308)	(573)	(224)	(157)	(62)	-	(148)	(3)	(764)	(93)	(350)	(350)	(114)	(557)	(156)	(117)	(280)	(2,260)	(1,451)		
	Annual Additions, Long Term Resources	130	141	305	212	642	3,359	161	156	142	921	746	2,055	131	850	778	83	96	469	2,124	3,617		
	Annual Additions, Short Term Resources	1,149	1,090	886	980	1,172	527	626	606	715	1,487	1,427	1,638	1,677	1,549	1,538	1,485	1,495	1,430	1,346	1,375		
	Total Annual Additions	1,279	1,231	1,191	1,192	1,813	3,885	787	762	857	2,408	2,173	3,692	1,809	2,399	2,316	1,569	1,591	1,898	3,470	4,992		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-72	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1 (Coal Early Retirement/Conversions)	-	-	-	-	(44)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(44)	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	185	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	-	555	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,100	-	-	-	-	-	-	-	-	1,920	3,640
	Utility Solar - PV - Utah-S	-	-	-	48	66	185	-	-	-	-	-	-	414	-	-	-	-	400	-	-	300	1,114
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	86	-	-	-	-	-	-	-	-	86
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	-	3	126	600	-	-	-	-	-	-	-	-	729
	Utility Solar+Storage - PV - Utah-N	-	-	159	12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	171	171
	Total Solar	-	-	159	60	66	285	-	-	-	-	3	126	1,100	-	-	-	-	400	-	909	571	3,109
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	124.9	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	-	6.7	-	-	6.8	130.0	-	15.3	-	157.1	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	69	116
	Energy Efficiency, UT	58	67	68	69	75	66	67	65	65	62	54	53	50	50	49	36	34	26	22	26	662	1,061
	Energy Efficiency, WY	10	12	13	14	18	16	16	17	18	17	15	14	13	12	11	9	8	7	5	5	110	250
	Energy Efficiency Total	74	85	87	90	100	89	91	88	89	87	75	74	69	67	65	49	46	36	30	35	881	1,428
	Battery Storage - Utah-N	-	-	-	-	-	-	-	-	-	285.0	-	-	-	-	-	-	-	-	-	720	285	1,005
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	405.0	-	-	-	-	-	-	-	-	-	-	405.0	405.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	75.0	240.0	-	315.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	-	-	277	300	247	204	206	300	300	300	300	-	122
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	-	(351)
	JimBridger 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	209	-	-	-	-	-	-	500	709
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,408	-	1,408
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	266	-	-	-	-	-	-	-	266
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	-	430
	Total Solar	-	-	-	-	-	905	-	-	-	-	-	-	-	475	100	-	-	-	430	1,408	905	3,318
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	7.5	-	-	-	128.0	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	43	43	47	47	39	36	41	39	37	33	31	30	29	26	26	26	26	24	24	410	682
	Energy Efficiency, WA	11	11	11	12	12	12	11	11	11	10	9	9	8	8	8	6	6	5	4	4	112	179
	Energy Efficiency Total	52	56	55	60	61	52	49	54	52	49	44	41	40	38	35	33	33	32	29	29	540	894
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	180	-	-	-	-	-	-	-	-	-	150	180	330
	Battery Storage - Willamette Valley	-	-	-	-	15	-	-	-	-	45	-	-	-	-	-	-	-	-	-	-	60	60
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	75	75
	Battery Storage - Walla Walla	-	-	-	-	45	-	-	-	-	75	-	-	-	-	-	-	-	-	-	90	120	210
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	959	557	614	645	235	254	233	290	1,048	995	1,075	1,075	1,075	1,075	1,075	1,059	994	1,059	1,075	583	820
	FOT West - Winter	151	131	269	304	314	249	255	259	309	323	313	343	309	302	253	173	151	151	-	-	257	228
	Existing Plant Retirements/Conversions	-	(308)	(573)	(224)	(45)	(62)	-	(148)	(3)	(764)	(93)	(506)	(306)	(114)	(557)	(156)	(117)	(280)	(2,260)	(1,451)		
	Annual Additions, Long Term Resources	130	141	317	211	402	3,252	148	150	141	1,201	749	1,341	1,209	589	708	82	95	468	1,846	3,602		
	Annual Additions, Short Term Resources	1,149	1,091	826	917	959	484	510	493	599	1,371	1,308	1,695	1,684	1,624	1,532	1,454	1,510	1,445	1,359	1,375		
	Total Annual Additions	1,279	1,231	1,143	1,128	1,361	3,735	658	643	740	2,572	2,057	3,036	2,892	2,213	2,240	1,536	1,605	1,913	3,206	4,977		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-73	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	(44)	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Hunter 1 (Coal Early Retirement/Conversions)	-	-	-	-	(418)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(418)	(418)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	185	-	-	370	-	-	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	185	-	185	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	185	-	-	370	-	185	-	185	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	327	293	-	-	-	-	-	-	-	-	-	327	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,061	-	-	-	-	-	-	-	-	-	1,061
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	327	293	1,061	-	-	-	-	-	-	-	-	2,247	3,601
	Utility Solar - PV - Utah-S	-	-	146	59	67	-	-	-	-	-	-	-	99	-	-	-	-	400	-	-	272	771
	Utility Solar - PV - WYSW	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	28	-	-	-	-	-	-	401	-	-	-	-	-	-	-	28	429
	Utility Solar+Storage - PV - GO	-	-	-	-	-	-	-	-	-	-	-	39	-	-	-	-	-	-	-	-	-	39
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	-	37	3	695	-	-	-	-	-	-	-	-	37	735
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	165	-	-	-	-	-	-	-	-	-	-	-	-	-	-	165	165
	Total Solar	-	-	146	59	67	293	-	-	-	37	3	734	500	-	-	-	-	400	-	909	602	3,148
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	11.0	-	113.8	-	-	-	-	8.3	-	-	5.1	11.0	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	11.0	6.7	113.8	-	12.0	-	-	15.3	-	157.1	21.6	55.6	382.2
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	69	73	68	67	68	65	64	54	53	52	50	49	36	34	27	23	22	667	1,066
	Energy Efficiency, WY	10	12	13	14	15	16	17	18	19	18	15	14	13	12	11	9	8	7	5	5	152	253
	Energy Efficiency Total	74	85	86	90	96	92	92	94	91	89	76	74	71	68	65	49	46	37	31	30	888	1,436
	Battery Storage - Utah-N	-	-	-	-	285.0	-	-	-	-	420.0	-	-	-	-	-	-	-	-	270	360	705	1,335
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	525.0	-	525.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	315.0	105.0	-	420.0
	FOT East - Summer	-	-	-	-	36	-	-	-	-	215	216	300	273	249	298	300	300	300	300	300	25	154
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	-	(351)
	JimBridger 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	234	-	-	-	-	-	-	-	235	-	-	-	-	-	-	234	469
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	67	-	405	472
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,408	-	1,408
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	266	-	-	-	-	-	-	-	240	-	-	-	-	-	-	266	506
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	363	-	-	363
	Total Solar	-	-	-	-	-	905	-	-	-	-	-	-	-	575	-	-	-	-	430	1,408	905	3,318
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.1	-	-	-	9.2	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	3.1	-	-	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	9.4	-	-	9.2	-	3.1	-	115.6	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	43	42	39	39	37	41	39	37	33	31	30	29	26	26	24	25	22	21	392	658
	Energy Efficiency, WA	11	10	11	12	12	12	12	11	11	10	9	9	8	8	8	6	6	5	4	4	112	178
	Energy Efficiency Total	52	49	55	55	53	52	50	54	52	49	44	41	40	38	35	33	32	31	27	26	522	869
	Battery Storage - Willamette Valley	-	-	-	-	60	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	60	90
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195	-	195
	Battery Storage - Walla Walla	-	-	-	-	180	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	180	285
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	959	617	672	1,075	470	563	538	596	1,075	1,075	1,075	1,075	1,075	1,075	1,075	988	924	1,060	1,075	756	903
	FOT West - Winter	151	131	268	303	314	181	188	190	239	251	242	269	238	207	196	113	94	93	-	-	222	183
	Existing Plant Retirements/Conversions	-	(308)	(573)	(224)	(420)	(62)	-	(148)	(3)	(764)	(93)	(506)	(350)	(114)	(557)	(156)	(117)	(280)	(2,260)	(1,451)		
	Annual Additions, Long Term Resources	130	134	303	204	856	3,263	150	155	142	933	423	2,218	611	693	479	82	281	468	1,974	3,714		
	Annual Additions, Short Term Resources	1,149	1,090	886	975	1,425	651	751	727	835	1,542	1,532	1,644	1,585	1,532	1,569	1,488	1,382	1,317	1,360	1,375		
	Total Annual Additions	1,279	1,224	1,189	1,179	2,280	3,914	901	883	978	2,474	1,955	3,862	2,197	2,224	2,048	1,570	1,664	1,785	3,333	5,089		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

	P-74	Capacity (MW)																				Resource Totals 1/	
		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Expansion Resources																						
	SCCT Frame NTN	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	185	-	-	-	-	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	185	-	370	-	-	925
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	620	-	-	-	-	-	-	-	-	-	-	620
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	1,100
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Total Wind	-	-	-	-	-	1,920	-	-	-	-	620	1,100	-	-	-	-	-	-	-	-	1,920	3,640
	Utility Solar - PV - Utah-S	-	-	146	59	67	28	-	-	-	-	-	409	-	-	-	-	-	400	-	-	300	1,109
	Utility Solar - PV - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	100
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	91	-	-	-	-	-	-	-	-	91
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	909
	Utility Solar - PV - Utah-N	-	-	-	-	-	-	-	-	64	37	3	626	-	-	-	-	-	-	-	-	100	729
	Utility Solar+Storage - PV - Utah-N	-	-	-	-	-	171	-	-	-	-	-	-	-	-	-	-	-	-	-	-	171	171
	Total Solar	-	-	146	59	67	199	-	-	64	37	3	1,035	91	-	-	-	-	500	-	909	571	3,109
	Demand Response, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	-	2.6
	Demand Response, ID-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	1.8	-	10.6
	Demand Response, ID-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	74.1	2.6	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	124.9	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.8	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	39.4	-	-	39.4
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.7	1.2	-	19.9
	Demand Response, UT-Ancillary Services	-	-	8.3	-	-	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	15.3	-	9.9	-	8.2	7.2	-	-	6.7	-	-	6.8	130.0	-	15.3	-	157.1	21.6	44.6	382.2
	Energy Efficiency, ID	6	6	6	7	8	7	7	7	7	7	6	6	6	6	6	4	4	3	3	3	70	117
	Energy Efficiency, UT	58	67	67	69	75	68	71	68	65	67	54	53	50	50	49	36	32	26	25	26	675	1,076
	Energy Efficiency, WY	10	12	13	14	18	16	17	19	19	18	15	14	13	12	11	9	8	7	5	5	155	254
	Energy Efficiency Total	74	85	86	90	100	92	96	94	91	92	75	74	69	67	65	49	45	37	33	35	899	1,448
	Battery Storage - Utah-N	-	-	-	-	30.0	-	-	-	-	300.0	-	-	-	-	-	-	-	-	-	660	330	990
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	90.0	-	-	-	-	-	-	-	-	-	300.0	90.0	390.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	285.0	-	-	285.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	23	-	300	246	284	246	248	300	300	300	300	2	127
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	-	(351)
	JimBridger 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Utility Solar - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	411	-	-	-	-	-	-	-	500	911
	Utility Solar - PV - Yakima	-	-	-	-	-	405	-	-	-	-	-	-	-	-	-	-	-	-	-	-	405	405
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,408	-	1,408
	Utility Solar - PV - Walla Walla	-	-	-	-	-	-	-	-	-	-	-	-	-	100	-	-	-	-	-	-	-	100
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	64	-	-	-	-	-	-	-	64
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	430	-	430
	Total Solar	-	-	-	-	-	905	-	-	-	-	-	-	411	164	-	-	-	-	-	1,838	905	3,318
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.3	-	-	23.3
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	35.7	-	-	35.7
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9.9	-	-	9.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	7.5	-	-	-	128.0	-	-	137.4
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	43	43	42	47	39	43	41	39	37	33	31	30	29	26	27	26	26	25	24	412	687
	Energy Efficiency, WA	11	11	11	12	12	12	12	11	11	11	9	9	8	8	8	6	6	5	4	4	113	180
	Energy Efficiency Total	52	55	56	56	61	52	56	54	52	49	44	41	40	38	35	34	33	32	30	29	543	900
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	240	-	-	-	-	-	-	-	-	75	60	240	375
	Battery Storage - Willamette Valley	-	-	-	-	15	-	-	-	-	75	-	-	-	-	-	-	-	-	-	-	90	90
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	90	-	-	-	-	-	-	-	-	30	-	90	120
	Battery Storage - Walla Walla	-	-	-	-	120	-	-	-	-	30	-	-	-	-	-	-	-	-	-	150	150	300
	Battery Storage - Yakima	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	959	618	677	710	285	308	284	342	1,075	1,046	1,075	1,075	1,075	1,075	1,075	940	872	1,051	1,075	625	831
	FOT West - Winter	151	131	269	304	314	255	261	265	315	329	318	349	357	358	298	218	196	195	-	-	259	244
	Existing Plant Retirements/Conversions	-	(308)	(573)	(224)	(84)	(62)	-	(66)	(3)	(764)	(93)	(506)	(350)	(114)	(557)	(156)	(117)	(280)	(2,260)	(1,451)		
	Annual Additions, Long Term Resources	130	140	303	205	508	3,168	160	156	206	1,003	749	2,250	611	278	608	83	278	569	1,551	4,002		
	Annual Additions, Short Term Resources	1,149	1,091	886	980	1,024	539	569	549	656	1,427	1,364	1,724	1,678	1,716	1,619	1,541	1,436	1,367	1,351	1,375		
	Total Annual Additions	1,279	1,231	1,190	1,185	1,531	3,708	729	705	862	2,430	2,114	3,973	2,289	1,994	2,226	1,624	1,714	1,936	2,902	5,377		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

APPENDIX L – STOCHASTIC SIMULATION RESULTS

Introduction

This appendix reports additional results for the Monte Carlo production cost simulations conducted with the Planning and Risk (PaR) model for the core, sensitivity and final screening cases. These results supplement the data presented in Volume I, Chapter 8 (Modeling and Portfolio Selection Results) of the IRP document. The results presented include the following:

- Statistics of the stochastic simulation results
- Components of portfolios' present value revenue requirements (PVRR)
- Energy-not-served
- Customer rate impact of portfolios in the final screen as compared with the preferred portfolio
- Loss of Load Probability of portfolios in the final screen as compared with the preferred portfolio

There are thirty Initial Development cases, ten C cases, eight CP cases, six FOT Risk Assessment cases, six Gateway and No Gas cases, eight Sensitivity cases, three Rebundled DSM cases, and five P-70 cases.

Table L.1 – Stochastic Mean PVRR, Initial Development Cases

Med Gas, Med CO_2					
Name	**PVRR ($m)**	**Name**	**PVRR ($m)**	**Name**	**PVRR ($m)**
P01	24,106	**P12**	23,678	**P30**	23,733
P02	24,919	**P13**	24,016	**P31**	23,484
P03	23,822	**P14**	23,786	**P32**	23,750
P04	23,775	**P15**	24,285	**P33**	23,809
P06	23,932	**P16**	23,889	**P34**	23,938
P07	23,819	**P17**	24,182	**P35**	23,666
P08	23,875	**P18**	24,376	**P45**	23,525
P09	23,760	**P19**	24,000	**P46**	23,413
P10	23,655	**P20**	25,118	**P53**	23,468
P11	23,768	**P28**	23,686	**P54**	23,616

Table L.2 – Stochastic Mean PVRR by Price Scenario, Initial Development Cases

Name	PVRR ($m)			
	Low Gas, No CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Social Cost of Carbon
P16	19,448	23,889	29,847	39,712
P17	21,013	24,182	28,858	36,415
P18	22,456	24,376	27,785	35,276
P19	20,194	24,000	29,224	38,396
P20	20,833	25,118	28,397	37,527

Table L.3 – Stochastic Mean PVRR, C Cases

Name	Med Gas, Med CO_2 PVRR ($m)
P31C	23,374
P36C	23,430
P45C	23,283
P46C	23,278
P46J23C	23,312
P47C	23,198
P48C	23,221
P53C	23,340
P53J23C	23,391
P54C	23,381

Table L.4 – Stochastic Mean PVRR by Price Scenario, CP Cases

Name	PVRR ($m)			
	Low Gas, No CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Social Cost of Carbon
P36CP	20,377	23,413	27,881	36,561
P45CP	20,094	23,192	27,786	36,934
P46CP	20,285	23,292	27,814	36,703
P46J23CP	20,306	23,303	27,812	36,555
P47CP	20,130	23,219	27,805	36,936
P48CP	20,173	23,205	27,736	36,798
P53CP	20,327	23,348	27,889	36,829
P45CNW	19,965	23,207	27,946	37,095

Table L.5 – Stochastic Mean PVRR, FOT Risk Assessment Cases

Name	Med Gas, Med CO_2 PVRR ($m)
P45CNW-FOT	24,075
P45CP-FOT	24,024
P46CP-FOT	24,099
P47CP-FOT	24,001
P48CP-FOT	24,098
P53CP-FOT	24,164

Table L.6 – Stochastic Mean PVRR, Gateway and No Gas Cases

Name	Med Gas, Med CO_2 PVRR ($m)
P-22CNW	23,603
P-23CNW	24,184
P-25CNW	24,239
P-26CNW	23,307
P29	23,328
P29PS	23,616

Table L.7 – Stochastic Mean PVRR, Sensitivity Cases

Name	Med Gas, Med CO_2 PVRR ($m)
S01	22,080
S02	24,346
S03	23,388
S04	23,308
S05	22,970
S06	24,038
S07	23,126
S08	23,186

Table L.8 – Stochastic Mean PVRR, DSM Rebundled Cases

Name	Med Gas, Med CO_2 PVRR ($m)
P45DP	23,281
P46DP	23,350
P53DP	23,409

Table L.9 – Stochastic Mean PVRR, P70 Cases

Name	Med Gas, Med CO_2 PVRR ($m)
P70	24,041
P71	24,010
P72	24,121
P73	24,261
P74	24,230

Table L.10 – Stochastic Risk Results, Initial Development Cases – Medium Gas, Medium CO_2

PVRR ($m)	Initial Cases Medium Gas, Medium CO_2				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P01	95	23,952	24,228	24,258	10,521
P02	97	24,759	25,056	25,089	10,723
P03	98	23,672	23,945	23,996	10,395
P04	142	23,558	23,909	23,978	9,758
P06	133	23,724	24,061	24,149	10,436
P07	133	23,610	23,950	24,038	10,396
P08	134	23,664	24,006	24,115	10,600
P09	131	23,562	23,882	23,996	10,514
P10	133	23,451	23,778	23,875	9,874
P11	98	23,617	23,886	23,941	10,415
P12	132	23,469	23,796	23,907	10,225
P13	94	23,872	24,133	24,185	10,532
P14	185	23,547	23,921	24,025	10,238
P15	93	24,129	24,387	24,422	10,127
P16	159	23,648	24,045	24,153	13,505
P17	110	24,021	24,303	24,370	10,953
P18	131	24,191	24,515	24,531	8,803
P19	143	23,784	24,154	24,225	11,377
P20	143	24,903	25,272	25,343	11,377
P28	98	23,540	23,811	23,859	10,438
P30	99	23,588	23,850	23,909	10,355
P31	98	23,340	23,607	23,658	10,252
P32	101	23,605	23,875	23,940	10,405
P33	134	23,607	23,938	24,034	10,168
P34	138	23,727	24,061	24,159	10,143
P35	106	23,499	23,795	23,851	9,818
P45	101	23,373	23,647	23,703	10,284
P46	108	23,258	23,565	23,594	9,951
P53	109	23,312	23,622	23,644	10,002
P54	102	23,471	23,738	23,792	10,305

Table L.11 – Stochastic Risk Results, Initial Development Cases – Low Gas, No CO_2

PVRR ($m)	Initial Cases Low Gas, No CO_2				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P16	19,448	19,295	19,555	19,593	19,743
P17	21,013	20,892	21,102	21,161	21,198
P18	22,456	22,315	22,592	22,623	22,693
P19	20,194	20,052	20,296	20,318	20,465
P20	20,833	20,702	20,913	20,952	21,080

Table L.12 – Stochastic Risk Results, Initial Development Cases – High Gas, High CO_2

PVRR ($m)	Initial Cases High Gas, High CO_2				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P16	29,847	29,555	30,056	30,202	30,322
P17	28,858	28,652	29,014	29,069	29,114
P18	27,785	27,575	27,947	28,030	28,084
P19	29,224	28,970	29,407	29,539	29,659
P20	28,397	28,151	28,575	28,700	28,794

Table L.13 – Stochastic Risk Results, Initial Development Cases – Social Cost of Carbon

PVRR ($m)	Initial Cases Social Cost of Carbon				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P16	19,448	19,295	19,555	19,593	19,743
P17	21,013	20,892	21,102	21,161	21,198
P18	22,456	22,315	22,592	22,623	22,693
P19	20,194	20,052	20,296	20,318	20,465
P20	20,833	20,702	20,913	20,952	21,080

Table L.14 – Stochastic Risk Results, C Cases – Medium Gas, Medium CO_2

PVRR ($m)	C Cases				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P31C	23,374	23,233	23,507	23,536	23,580
P36C	23,430	23,213	23,574	23,677	23,811
P45C	23,283	23,131	23,409	23,449	23,491
P46C	23,278	23,125	23,404	23,458	23,485
P46J23C	23,312	23,160	23,445	23,506	23,526
P47C	23,198	23,045	23,333	23,371	23,411
P48C	23,221	23,073	23,342	23,396	23,436
P53C	23,340	23,185	23,466	23,518	23,558
P53J23C	23,391	23,235	23,525	23,580	23,612
P54C	23,381	23,233	23,509	23,547	23,593

Table L.15 – Stochastic Risk Results, CP Cases – Medium Gas, Medium CO_2

PVRR ($m)	CP Cases Medium Gas, Medium CO_2				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P36CP	23,413	23,194	23,561	23,657	23,780
P45CP	23,192	23,043	23,322	23,367	23,397
P46CP	23,292	23,143	23,426	23,464	23,499
P46J23CP	23,303	23,144	23,456	23,492	23,534
P47CP	23,219	23,067	23,349	23,393	23,435
P48CP	23,205	23,051	23,327	23,374	23,421
P53CP	23,348	23,199	23,476	23,521	23,565
P45CNW	23,207	23,062	23,348	23,372	23,409

Table L.16 – Stochastic Risk Results, CP Cases – Low Gas, Low CO_2

PVRR ($m)	CP Cases Low Gas, No CO_2				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P36CP	20,377	20,229	20,485	20,515	20,643
P45CP	20,094	20,001	20,187	20,216	20,232
P46CP	20,285	20,187	20,387	20,409	20,427
P46J23CP	20,306	20,195	20,412	20,427	20,487
P47CP	20,130	20,030	20,223	20,264	20,279
P48CP	20,173	20,070	20,268	20,293	20,320
P53CP	20,327	20,228	20,428	20,450	20,474
P45CPNW	19,965	19,878	20,052	20,085	20,101

Table L.17 – Stochastic Risk Results, CP Cases – High Gas, High CO_2

PVRR ($m)	CP Cases High Gas, High CO_2				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P36CP	27,881	27,612	28,091	28,193	28,321
P45CP	27,786	27,585	27,947	28,039	28,069
P46CP	27,814	27,596	27,971	28,067	28,097
P46J23CP	27,812	27,595	28,008	28,059	28,093
P47CP	27,805	27,596	27,957	28,060	28,091
P48CP	27,736	27,528	27,893	27,990	28,028
P53CP	27,889	27,672	28,051	28,144	28,180
P45CPNW	27,946	27,748	28,121	28,190	28,222

Table L.18 – Stochastic Risk Results, CP– Social Cost of Carbon

PVRR ($m)	CP Cases Social Cost of Carbon				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P36CP	36,561	36,278	36,808	36,887	36,953
P45CP	36,934	36,713	37,137	37,141	37,207
P46CP	36,703	36,451	36,897	36,923	36,982
P46J23CP	36,555	36,296	36,755	36,784	36,835
P47CP	36,936	36,699	37,139	37,150	37,215
P48CP	36,798	36,567	37,007	37,020	37,078
P53CP	36,829	36,576	37,025	37,043	37,109
P45CPNW	37,095	36,877	37,292	37,303	37,373

Table L.19 – Stochastic Risk Results, FOT Risk Assessment Cases – Medium Gas, Medium CO_2

PVRR ($m)	FOT Cases				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P45CNW	24,075	23,917	24,212	24,258	24,298
P45CP	24,024	23,867	24,160	24,193	24,264
P46CP	24,099	23,924	24,239	24,296	24,314
P47CP	24,001	23,835	24,130	24,156	24,236
P48CP	24,098	23,927	24,241	24,293	24,333
P53CP	24,164	23,986	24,305	24,357	24,399

Table L.20 – Stochastic Risk Results, Gateway and No Gas Cases – Medium Gas, Medium CO_2

PVRR ($m)	Gateway and No Gas Studies				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P-22CNW	23,603	23,470	23,733	23,772	23,805
P-23CNW	24,184	24,037	24,307	24,358	24,390
P-25CNW	24,239	24,093	24,372	24,414	24,446
P-26CNW	23,307	23,162	23,454	23,479	23,518
P29	23,328	23,182	23,467	23,503	23,536
P29PS	23,616	23,439	23,777	23,803	23,874

Table L.21 – Stochastic Risk Results, Sensitivity Cases – Medium Gas, Medium CO_2

PVRR ($m)	Sensitivity Studies				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
S01	22,080	21,939	22,208	22,248	22,282
S02	24,346	24,182	24,475	24,527	24,601
S03	23,388	23,235	23,514	23,550	23,615
S04	23,308	23,161	23,442	23,480	23,519
S05	22,970	22,827	23,102	23,134	23,177
S06	24,038	23,902	24,183	24,207	24,229
S07	23,126	22,992	23,254	23,301	23,334
S08	23,186	23,039	23,313	23,350	23,386
P45CPNW	23,207	23,062	23,348	23,372	23,409

Table L.22 – Stochastic Risk Results, DSM Rebundled Cases – Medium Gas Medium CO_2

PVRR ($m)	DP Studies				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P45DP	23,104	22,956	23,248	23,268	23,312
P46DP	23,174	23,012	23,321	23,344	23,378
P53DP	23,232	23,070	23,381	23,401	23,444

Table L.23 – Stochastic Risk Results, P70 Cases – Medium Gas, Medium CO_2

PVRR ($m)	P70 Studies				
	Standard Deviation	5th percentile	90th percentile	95th percentile	Upper Tail (mean of 3 Highest) No Fixed Costs
P70	24,041	23,882	24,161	24,204	24,248
P71	24,010	23,859	24,139	24,165	24,206
P72	24,121	23,969	24,238	24,275	24,317
P73	24,261	24,100	24,391	24,426	24,465
P74	24,230	24,075	24,364	24,381	24,423

Table L.24 – Stochastic Risk Adjusted PVRR, Initial Cases

Med Gas, Med CO2					
Name	PVRR ($m)	Name	PVRR ($m)	Name	PVRR ($m)
P01	25,319	**P12**	24,873	**P30**	24,928
P02	26,174	**P13**	25,226	**P31**	24,667
P03	25,022	**P14**	24,987	**P32**	24,947
P04	24,974	**P15**	25,506	**P33**	25,010
P06	25,139	**P16**	25,097	**P34**	25,146
P07	25,021	**P17**	25,400	**P35**	24,858
P08	25,081	**P18**	25,602	**P45**	24,710
P09	24,960	**P19**	25,211	**P46**	24,593
P10	24,848	**P20**	26,385	**P53**	24,650
P11	24,966	**P28**	24,879	**P54**	24,806

Table L.25 – Stochastic Risk Adjusted PVRR by Price Scenario, Initial Cases

Name	PVRR ($m)			
	Low Gas, No CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Social Cost of Carbon
P16	20,427	25,097	31,357	41,717
P17	22,071	25,400	30,312	38,247
P18	23,587	25,602	29,187	37,051
P19	21,209	25,211	30,701	40,334
P20	21,881	26,385	29,832	39,421

Table L.26 – Stochastic Risk Adjusted PVRR, C Cases

Name	Med Gas, Med CO_2 PVRR ($m)
P31C	24,551
P36C	24,614
P45C	24,456
P46C	24,451
P46J23C	24,488
P47C	24,367
P48C	24,391
P53C	24,516
P53J23C	24,570
P54C	24,558

Table L.27 – Stochastic Risk Adjusted PVRR by Price Scenario, CP Cases

Name	PVRR ($m)			
	Low Gas, No CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Social Cost of Carbon
P36CP	21,403	24,595	29,290	38,405
P45CP	21,105	24,360	29,188	38,791
P46CP	21,305	24,465	29,217	38,550
P46J23CP	21,327	24,478	29,215	38,394
P47CP	21,143	24,388	29,208	38,794
P48CP	21,187	24,374	29,135	38,649
P53CP	21,349	24,524	29,296	38,681
P45CNW	20,969	24,376	29,355	38,960

Table L.28 – Stochastic Risk Adjusted PVRR, FOT Risk Assessment Cases

Name	Med Gas, Med CO2 PVRR ($m)
P45CNW	25,288
P45CP	25,233
P46CP	25,314
P47CP	25,209
P48CP	25,312
P53CP	25,382

Table L.29 – Stochastic Risk Adjusted PVRR, Gateway and No Gas Cases

Name	Med Gas, Med CO_2 PVRR ($m)
P-22CNW	24,792
P-23CNW	25,402
P-25CNW	25,460
P-26CNW	24,481
P29	24,503
P29PS	24,806

Table L.30 – Stochastic Risk Adjusted PVRR, Sensitivity Cases

Name	Med Gas, Med CO_2 PVRR ($m)
S01	23,193
S02	25,572
S03	24,565
S04	24,482
S05	24,126
S06	25,248
S07	24,291
S08	24,353

Table L.31 – Stochastic Risk Adjusted PVRR, DSM Rebundled Cases

Name	Med Gas, Med CO_2 PVRR ($m)
P45DP	24,453
P46DP	24,526
P53DP	24,587

Table L.32 – Stochastic Risk Adjusted PVRR, P70 Cases

Name	Med Gas, Med CO_2 PVRR ($m)
P70	25,251
P71	25,218
P72	25,334
P73	25,482
P74	25,449

Table L.33 – Carbon Dioxide Emissions, Initial Cases

Med Gas, Med CO_2					
Name	**CO_2 (thousand tons)**	**Name**	**CO_2 (thousand tons)**	**Name**	**CO_2 (thousand tons)**
P01	616,896	**P12**	579,167	**P30**	587,905
P02	605,872	**P13**	604,396	**P31**	588,421
P03	595,728	**P14**	535,774	**P32**	583,565
P04	567,901	**P15**	472,569	**P33**	569,586
P06	585,907	**P16**	669,944	**P34**	568,422
P07	581,583	**P17**	475,390	**P35**	557,489
P08	595,956	**P18**	427,110	**P45**	583,981
P09	597,855	**P19**	607,157	**P46**	560,199
P10	571,707	**P20**	607,157	**P53**	562,025
P11	596,911	**P28**	594,322	**P54**	584,377

Table L.34 – Carbon Dioxide Emissions by Price Scenario, Initial Cases

Name	**CO_2 (thousand tons)**			
	Low Gas, No CO_2	**Med Gas, Med CO_2**	**High Gas, High CO_2**	**Social Cost of Carbon**
P16	674,184	669,944	653,963	496,702
P17	465,998	475,390	478,795	366,220
P18	418,674	427,110	431,628	321,000
P19	607,941	607,157	598,587	459,469
P20	579,150	607,157	572,793	437,132

Table L.35 – Carbon Dioxide Emissions, C Cases

Name	Med Gas, Med CO_2 (thousand tons)
P31C	588,334
P36C	550,233
P45C	578,607
P46C	560,210
P46J23C	553,673
P47C	573,088
P48C	567,025
P53C	562,972
P53J23C	556,990
P54C	581,465

Table L.36 – Carbon Dioxide Emissions by Price Scenario, CP Cases

Name	CO_2 (thousand tons)			
	Low Gas, No CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Social Cost of Carbon
P36CP	549,329	549,427	544,092	405,969
P45CP	577,806	577,439	571,643	432,168
P46CP	555,322	557,824	553,331	414,320
P46J23CP	549,304	552,065	549,152	411,129
P47CP	572,966	573,649	568,183	429,251
P48CP	567,163	567,889	562,313	424,073
P53CP	558,186	560,553	556,201	418,116
P45CNW	586,648	585,641	579,073	437,599

Table L.37 – Carbon Dioxide Emissions, FOT Risk Assessment Cases

Name	Med Gas, Med CO2 (thousand tons)
P45CNW-FOT	542,046
P45CP-FOT	540,134
P46CP-FOT	522,510
P47CP-FOT	535,827
P48CP-FOT	533,930
P53CP-FOT	525,364

Table L.38 – Carbon Dioxide Emissions, Gateway and No Gas Cases

Name	Med Gas, Med CO2 (thousand tons)
P-22CNW	581,028
P-23CNW	544,811
P-25CNW	580,014
P-26CNW	579,969
P29	580,126
P29PS	576,806

Table L.39 – Carbon Dioxide Emissions, Sensitivity Cases

Name	Med Gas, Med CO2 (thousand tons)
S01	569,357
S02	607,239
S03	590,315
S04	590,401
S05	580,957
S06	586,136
S07	583,986
S08	581,368

Table L.40 – Carbon Dioxide Emissions, DSM Rebundled Cases

Name	Med Gas, Med CO2 (thousand tons)
P45DP	578,417
P46DP	556,742
P53DP	559,529

Table L.41 – Carbon Dioxide Emissions, P70 Cases

Name	Med Gas, Med CO2 (thousand tons)
P70	25,251
P71	25,218
P72	25,334
P73	25,482
P74	25,449

Table L.42 – Average Annual Energy Not Served, Initial Development Cases

Med Gas, Med CO_2					
Name	**GWh**	**Name**	**GWh**	**Name**	**GWh**
P01	4.3	**P12**	5.3	**P30**	6.4
P02	5.6	**P13**	5.3	**P31**	5.8
P03	5.3	**P14**	10.2	**P32**	5.5
P04	7.2	**P15**	7.9	**P33**	4.7
P06	4.6	**P16**	4.4	**P34**	5.0
P07	4.6	**P17**	37.9	**P35**	6.7
P08	5.8	**P18**	73.3	**P45**	5.2
P09	5.9	**P19**	4.5	**P46**	8.1
P10	6.0	**P20**	4.5	**P53**	8.3
P11	5.1	**P28**	5.5	**P54**	5.8

Table L.43 – Average Annual ENS by Price Scenario, Initial Development Cases

Name	GWh			
	Low Gas, No CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Social Cost of Carbon
P16	4.4	4.4	4.4	4.5
P17	37.9	37.9	38.0	37.9
P18	73.8	73.3	73.9	73.9
P19	4.5	4.5	4.5	4.5
P20	4.6	4.5	4.6	4.6

Table L.44 – Average Annual Energy Not Served, C Cases

Name	Med Gas, Med CO_2 GWh
P31C	6.8
P36C	8.9
P45C	6.7
P46C	7.2
P46J23C	8.3
P47C	8.1
P48C	7.5
P53C	7.4
P53J23C	8.3
P54C	7.7

Table L.45 – Average Annual Energy Not Served by Price Scenario, CP Cases

Name	GWh			
	Low Gas, No CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Social Cost of Carbon
P36CP	7.5	7.5	7.5	7.5
P45CP	6.3	6.3	6.4	6.3
P46CP	8.4	8.4	8.4	8.4
P46J23CP	9.1	9.1	9.1	9.1
P47CP	8.9	8.9	8.9	8.9
P48CP	8.3	8.3	8.3	8.3
P53CP	8.4	8.4	8.4	8.4
P45CNW	5.4	5.4	5.4	5.4

Table L.46 – Average Annual Energy Not Served, FOT Risk Assessment Cases

Name	Med Gas, Med CO_2 GWh
P45CNW-FOT	5.2
P45CP-FOT	6.2
P46CP-FOT	8.6
P47CP-FOT	6.5
P48CP-FOT	7.6
P53CP-FOT	8.5

Table L.47 – Average Annual Energy Not Served, Gateway and No Gas Cases

Name	Med Gas, Med CO_2 GWh
P-22CNW	4.9
P-23CNW	4.8
P-25CNW	4.0
P-26CNW	4.0
P29	4.2
P29PS	30.8

Table L.48 – Average Annual Energy Not Served, Sensitivity Cases

Name	Med Gas, Med CO_2 GWh
S01	3.5
S02	8.4
S03	7.3
S04	5.1
S05	5.4
S06	6.5
S07	5.6
S08	5.5

Table L.49 – Average Annual Energy Not Served, DSM Rebundled Cases

Name	Med Gas, Med CO_2 GWh
P45DP	6.7
P46DP	8.6
P53DP	8.6

Table L.50 – Average Annual Energy Not Served, P70 Cases

Name	Med Gas, Med CO_2 GWh
P70	25250.8
P71	25218.3
P72	25334.3
P73	25481.9
P74	25449.2

Table L.51 – PVRR Cost Components by Price Scenario, Initial Cases, Medium Gas, Medium CO_2

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P01	10,526	245	463	3,179	(760)	939	(5,190)	886	13,818	24,106
P02	10,520	318	461	3,078	(756)	926	(5,024)	957	14,440	24,919
P03	10,459	260	462	2,971	(764)	911	(5,076)	919	13,680	23,822
P04	9,815	236	527	2,846	(772)	987	(5,181)	890	14,426	23,775
P06	10,258	262	491	2,923	(765)	972	(4,986)	902	13,874	23,932
P07	10,196	265	496	2,886	(769)	972	(4,956)	931	13,799	23,819
P08	10,465	259	460	2,968	(767)	926	(5,025)	918	13,672	23,875
P09	10,498	261	459	2,990	(769)	897	(5,107)	908	13,622	23,760
P10	10,017	237	512	2,866	(765)	982	(5,246)	898	14,154	23,655
P11	10,496	261	464	2,987	(766)	926	(5,095)	900	13,595	23,768
P12	10,130	255	475	2,863	(760)	979	(5,022)	928	13,828	23,678
P13	10,470	260	460	3,065	(760)	903	(5,028)	921	13,726	24,016
P14	9,855	289	518	2,594	(763)	989	(4,870)	1,081	14,093	23,786
P15	10,246	380	580	1,898	(750)	1,105	(4,721)	1,171	14,376	24,285
P16	11,737	350	453	3,659	(315)	875	(4,936)	1,234	10,833	23,889
P17	10,322	421	556	1,914	(773)	1,020	(4,439)	1,684	13,476	24,182
P18	8,799	271	632	1,512	(684)	1,258	(4,894)	1,613	15,869	24,376
P19	10,811	320	483	3,180	(792)	715	(4,844)	1,089	13,039	24,000
P20	10,811	320	483	3,180	(792)	715	(4,844)	1,089	14,157	25,118
P28	10,444	258	464	2,968	(766)	923	(5,022)	922	13,495	23,686
P30	10,411	258	470	2,928	(767)	974	(5,066)	899	13,625	23,733
P31	10,341	256	463	2,925	(757)	906	(5,037)	912	13,477	23,484
P32	10,337	269	484	2,898	(769)	977	(4,981)	930	13,605	23,750
P33	10,088	248	505	2,810	(762)	995	(5,015)	917	14,023	23,809

Table L.52 Continued– PVRR Cost Components by Price Scenario, Initial Cases, Medium Gas, Medium CO_2

P34	10,023	257	511	2,806	(760)	950	(4,973)	929	14,194	23,938
P35	10,103	280	502	2,700	(760)	973	(5,187)	963	14,092	23,666
P45	10,343	268	471	2,892	(766)	915	(5,021)	923	13,500	23,524
P46	10,137	281	478	2,669	(759)	905	(4,976)	967	13,712	23,413
P53	10,158	281	478	2,688	(760)	905	(4,977)	966	13,730	23,468
P54	10,321	262	468	2,865	(702)	910	(5,014)	935	13,573	23,616

Table L.53 – PVRR Cost Components by Price Scenario, Initial Cases, Low Gas, No CO_2

	Stochastic PVRR ($ millions)									
Name	**Thermal Fuel**	**Variable O&M incl. FOT**	**Long Term Contracts**	**Emissions**	**Renewable**	**DSM**	**System Balancing Sales**	**System Balancing Purchases**	**Capital and Fixed O&M Cost**	**Total PVRR**
P16	9,901	351	442	0	(311)	875	(3,412)	768	10,833	19,448
P17	8,213	430	546	0	(766)	1,020	(3,073)	1,168	13,476	21,013
P18	7,228	282	621	0	(684)	1,258	(3,338)	1,218	15,871	22,456
P19	9,058	323	473	0	(787)	715	(3,342)	714	13,039	20,194
P20	8,585	261	489	0	(743)	1,026	(3,557)	614	14,158	20,833

Table L.54 – PVRR Cost Components by Price Scenario, Initial Cases, High Gas, High CO_2

	Stochastic PVRR ($ millions)									
Name	**Thermal Fuel**	**Variable O&M incl. FOT**	**Long Term Contracts**	**Emissions**	**Renewable**	**DSM**	**System Balancing Sales**	**System Balancing Purchases**	**Capital and Fixed O&M Cost**	**Total PVRR**
P16	13,968	307	465	6,855	(317)	875	(5,285)	2,145	10,833	29,847
P17	12,935	372	568	3,720	(780)	1,020	(4,868)	2,416	13,476	28,858
P18	10,760	224	644	2,925	(688)	1,258	(5,417)	2,211	15,868	27,785
P19	13,000	281	495	6,015	(801)	715	(5,342)	1,821	13,039	29,224
P20	12,097	217	511	5,437	(753)	1,026	(5,793)	1,499	14,156	28,397

Table L.55 – PVRR Cost Components by Price Scenario, Initial Cases, Social Cost of Carbon

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P45CP	9,129	289	532	15,098	(813)	906	(4,844)	3,263	13,375	36,934
P46CP	9,074	323	539	14,571	(897)	908	(4,795)	3,287	13,694	36,703
P47CP	9,117	291	538	15,028	(831)	862	(4,818)	3,315	13,434	36,936
P48CP	9,094	298	538	14,875	(830)	904	(4,853)	3,275	13,496	36,798
P53CP	9,113	322	539	14,696	(897)	908	(4,818)	3,254	13,712	36,829

Table L.56 – PVRR Cost Components, C Cases, Medium Gas, Medium CO_2

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P31C	10,266	252	473	2,929	(763)	934	(4,948)	965	13,265	23,374
P36C	9,998	282	521	2,603	(740)	935	(4,860)	1,110	13,581	23,430
P45C	10,139	248	479	2,865	(764)	893	(5,006)	972	13,458	23,283
P46C	10,109	282	485	2,676	(847)	901	(4,970)	981	13,659	23,278
P46J23C	10,058	282	499	2,641	(845)	941	(4,966)	993	13,709	23,312
P47C	10,104	253	501	2,800	(782)	893	(4,994)	998	13,426	23,198
P48C	10,057	256	506	2,741	(780)	910	(5,000)	992	13,539	23,221
P53C	10,142	282	485	2,699	(847)	901	(4,974)	976	13,677	23,340
P53J23C	10,104	282	499	2,665	(845)	941	(4,973)	983	13,735	23,391
P54C	10,189	252	468	2,882	(759)	915	(4,970)	982	13,422	23,381

Table L.57 – PVRR Cost Components, CP Cases, Medium Gas Medium CO_2

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P36CP	9,982	282	520	2,599	(742)	975	(4,877)	1,090	13,582	23,413
P45CP	10,116	249	497	2,852	(764)	906	(5,008)	970	13,375	23,192
P46CP	10,024	271	504	2,652	(846)	908	(4,941)	1,025	13,694	23,292
P46J23CP	10,000	275	504	2,626	(845)	955	(4,950)	1,014	13,723	23,303
P47CP	10,109	252	503	2,804	(782)	862	(4,980)	1,017	13,434	23,219
P48CP	10,076	257	503	2,749	(780)	904	(4,999)	998	13,496	23,205
P53CP	10,055	271	504	2,674	(846)	908	(4,946)	1,017	13,712	23,348
P45CNW	10,280	258	494	2,933	(792)	932	(4,997)	988	13,111	23,207

Table L.58 – PVRR Cost Components, CP Cases, Low Gas No CO_2

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P36CP	8,383	287	510	0	(734)	975	(3,350)	724	13,583	20,377
P45CP	8,603	254	487	0	(758)	906	(3,426)	653	13,375	20,094
P46CP	8,437	275	493	0	(840)	908	(3,380)	696	13,694	20,285
P46J23CP	8,379	278	494	0	(838)	955	(3,382)	696	13,724	20,306
P47CP	8,576	257	492	0	(776)	862	(3,406)	690	13,434	20,130
P48CP	8,529	263	492	0	(774)	904	(3,418)	679	13,497	20,173
P53CP	8,470	275	493	0	(840)	908	(3,383)	691	13,712	20,327
P45CPNW	8,731	262	483	0	(786)	932	(3,424)	654	13,112	19,965

Table L.59 – PVRR Cost Components, CP Cases, High Gas High CO_2

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P36CP	11,983	239	532	4,888	(750)	975	(5,357)	1,789	13,582	27,881
P45CP	12,054	208	509	5,389	(768)	906	(5,516)	1,631	13,374	27,786
P46CP	12,065	230	516	5,025	(851)	908	(5,452)	1,681	13,693	27,814
P46J23CP	12,084	234	516	4,982	(850)	955	(5,479)	1,647	13,723	27,812
P47CP	12,066	211	515	5,309	(786)	862	(5,487)	1,683	13,433	27,805
P48CP	12,039	216	515	5,200	(784)	904	(5,508)	1,659	13,495	27,736
P53CP	12,101	230	516	5,073	(851)	908	(5,463)	1,664	13,711	27,889
P45CPNW	12,315	217	506	5,534	(796)	932	(5,488)	1,679	13,110	28,009

Table L.60 – PVRR Cost Components, CP Cases, Social Cost of Carbon

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P36CP	9,031	324	540	14,444	(897)	955	(4,820)	3,254	13,723	36,555
P45CP	9,117	291	538	15,028	(831)	862	(4,818)	3,315	13,434	36,936
P46CP	9,094	298	538	14,875	(830)	904	(4,853)	3,275	13,496	36,798
P46J23CP	9,094	298	538	14,875	(830)	904	(4,853)	3,275	13,496	36,798
P47CP	9,113	322	539	14,696	(897)	908	(4,818)	3,254	13,712	36,829
P48CP	10,489	437	488	17,102	(353)	875	(4,274)	4,113	10,833	39,712
P53CP	9,328	441	592	13,132	(831)	1,020	(4,531)	3,788	13,476	36,415
P45CPNW	7,867	281	667	11,726	(729)	1,258	(5,207)	3,544	15,869	35,276

Table L.61 – PVRR Cost Components, FOT Cases, Medium Gas Medium CO_2

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P45CNW-FOT	9,588	245	499	2,680	(815)	945	(3,093)	723	13,304	24,075
P45CP-FOT	9,507	238	498	2,671	(806)	903	(3,090)	724	13,379	24,024
P46CP-FOT	9,414	259	508	2,492	(809)	944	(3,073)	773	13,591	24,099
P47CP-FOT	9,515	249	495	2,620	(785)	862	(3,103)	703	13,445	24,001
P48CP-FOT	9,602	264	489	2,596	(844)	890	(3,095)	728	13,468	24,098
P53CP-FOT	9,447	258	508	2,515	(809)	944	(3,074)	766	13,609	24,164

Table L.62 – PVRR Cost Components, Gateway and No Gas Cases, Medium Gas Medium CO_2

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P-22CNW	10,181	246	491	2,883	(772)	888	(5,012)	910	13,788	23,603
P-23CNW	9,869	277	495	2,562	(776)	957	(4,965)	961	14,804	24,184
P-25CNW	10,145	249	463	2,872	(738)	903	(5,024)	843	14,527	24,239
P-26CNW	10,183	257	472	2,888	(800)	934	(4,916)	988	13,301	23,307
P29	10,184	257	467	2,890	(800)	934	(4,916)	993	13,319	23,328
P29PS	9,921	205	568	2,836	(771)	940	(4,778)	1,292	13,402	23,616

Table L.63 – PVRR Cost Components, Sensitivity Cases, Medium Gas Medium CO_2

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
S01	9,946	240	466	2,836	(790)	843	(4,997)	872	12,665	22,080
S02	10,724	291	486	3,068	(794)	896	(4,855)	1,144	13,386	24,346
S03	10,430	277	485	2,975	(774)	942	(5,007)	989	13,071	23,388
S04	10,413	270	481	2,973	(777)	923	(4,995)	988	13,032	23,308
S05	10,177	246	493	2,883	(775)	920	(4,929)	969	12,985	22,970
S06	10,755	422	498	2,956	(769)	1,067	(5,059)	1,005	13,163	24,038
S07	10,233	246	498	2,904	(760)	922	(4,952)	1,007	13,028	23,126
S08	10,184	248	503	2,900	(770)	895	(4,998)	986	13,238	23,186

Table L.64 – PVRR Cost Components, DSM Rebundled Cases, Medium Gas Medium CO_2

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P45DP	10,148	250	497	2,858	(780)	889	(4,899)	993	13,325	23,281
P46DP	10,013	272	505	2,648	(845)	887	(4,925)	1,018	13,778	23,350
P53DP	10,046	271	505	2,671	(846)	887	(4,930)	1,010	13,795	23,409

Table L.65 – PVRR Cost Components, P70 Cases, Medium Gas Medium CO_2

Name	Stochastic PVRR ($ millions)									
	Thermal Fuel	Variable O&M incl. FOT	Long Term Contracts	Emissions	Renewable	DSM	System Balancing Sales	System Balancing Purchases	Capital and Fixed O&M Cost	Total PVRR
P70	10,454	249	487	3,111	(761)	992	(5,239)	920	14,221	24,433
P71	10,380	232	476	3,116	(761)	999	(5,182)	891	14,269	24,419
P72	10,479	244	470	3,161	(759)	959	(5,159)	887	14,225	24,508
P73	10,455	258	501	3,034	(758)	950	(5,135)	954	14,397	24,656
P74	10,523	248	467	3,178	(761)	984	(5,138)	873	14,244	24,617

Table L.66 – 10-year Average Incremental Customer Rate Impact*

$ Millions	10-year Average Incremental Customer Rate Impact (2019 - 2028)									
	Low Gas, No $C0_2$		Medium Gas, Medium CO_2		High Gas, High CO_2		Social Cost of Carbon		Average	
	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank
P45CNW	0	4	0	5	0	5	0	6	0	5
P36CP	114	8	102	8	81	8	9	8	77	8
P45CP	(1)	3	(1)	3	(1)	3	0	7	(0)	4
P46CP	4	5	(0)	4	(1)	4	(30)	1	(7)	1
P46J23CP	50	7	34	7	19	7	(28)	2	19	7
P47CP	(7)	1	(5)	1	(2)	2	(1)	5	(3)	2
P48CP	(5)	2	(4)	2	(2)	1	(2)	4	(3)	3
P53CP	18	6	15	6	16	6	(7)	3	11	6

*The relative difference in customer rate impacts is negligible and no adjustment to the selection of P-45CNW as the preferred portfolio.

Table L.67 – 20-year Average Incremental Customer Rate Impact *

	20-year Average Incremental Customer Rate Impact (2019 - 2038)									
	Low Gas, No $C0_2$		Medium Gas, Medium CO_2		High Gas, High CO_2		Social Cost of Carbon		Average	
$ Millions	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank
P45CNW	0	1	0	6	0	8	0	8	0	7
P36CP	50	8	21	8	(20)	7	(45)	5	2	8
P45CP	35	7	5	7	(30)	6	(20)	7	(3)	6
P46CP	25	5	(12)	3	(51)	3	(56)	2	(24)	2
P46J23CP	4	2	(33)	1	(75)	1	(90)	1	(48)	1
P47CP	23	4	(5)	5	(37)	5	(27)	6	(11)	5
P48CP	22	3	(13)	2	(51)	2	(46)	4	(22)	3
P53CP	29	6	(7)	4	(45)	4	(47)	3	(17)	4

*The relative difference in customer rate impacts is negligible and no adjustment to the selection of P-45CNW as the preferred portfolio.

Table L.68 – Loss of Load Probability, Major (> 25,000 MWh) July Event, Medium Gas Medium CO_2

Year	P45CNW - Preferred Portfolio	P36CP	P45CP	P46CP	P46J23CP	P47CP	P48CP	P53CP
2019	2%	0%	2%	2%	2%	2%	2%	2%
2020	0%	0%	0%	0%	0%	0%	0%	0%
2021	0%	0%	0%	0%	0%	0%	0%	0%
2022	2%	2%	2%	2%	2%	2%	2%	2%
2023	0%	0%	0%	0%	0%	0%	0%	0%
2024	0%	0%	0%	0%	0%	0%	0%	0%
2025	0%	0%	0%	0%	0%	0%	0%	0%
2026	0%	2%	0%	0%	0%	0%	0%	0%
2027	0%	2%	0%	0%	0%	0%	0%	0%
2028	0%	4%	0%	0%	0%	0%	0%	0%
2029	4%	2%	4%	2%	4%	4%	4%	2%
2030	0%	0%	0%	2%	2%	0%	0%	0%
2031	0%	0%	0%	0%	0%	0%	0%	0%
2032	0%	0%	0%	0%	0%	0%	0%	0%
2033	2%	0%	6%	6%	12%	2%	0%	6%
2034	0%	2%	0%	0%	2%	0%	2%	0%
2035	12%	0%	6%	12%	14%	12%	14%	12%
2036	6%	2%	0%	8%	10%	14%	8%	8%
2037	2%	18%	2%	24%	20%	24%	22%	24%
2038	14%	24%	8%	28%	22%	26%	26%	28%

Table L.69 – Summer Peak, Average Loss of Load Probability, Medium Gas Medium CO_2

Event Size (MWh)	Average for operating years 2019 through 2028							
	P45CNW - Preferred Portfolio	P36CP	P45CP	P46CP	P46J23CP	P47CP	P48CP	P53CP
> 0	12%	11%	12%	11%	12%	12%	12%	11%
> 1,000	5%	8%	5%	6%	6%	6%	5%	6%
> 10,000	1%	3%	1%	1%	1%	1%	1%	1%
> 25,000	0%	1%	0%	0%	0%	0%	0%	0%
> 50,000	0%	0%	0%	0%	0%	0%	0%	0%
> 100,000	0%	0%	0%	0%	0%	0%	0%	0%
> 500,000	0%	0%	0%	0%	0%	0%	0%	0%

Event Size (MWh)	Average for operating years 2019 through 2038							
	P45CNW - Preferred Portfolio	P36CP	P45CP	P46CP	P46J23CP	P47CP	P48CP	P53CP
> 0	21%	15%	16%	22%	24%	24%	22%	22%
> 1,000	15%	12%	12%	17%	19%	18%	18%	17%
> 10,000	6%	6%	4%	9%	10%	9%	9%	9%
> 25,000	2%	0%	2%	4%	5%	4%	4%	4%
> 50,000	1%	1%	0%	2%	2%	2%	1%	2%
> 100,000	0%	1%	0%	0%	0%	0%	0%	0%
> 500,000	0%	0%	0%	0%	0%	0%	0%	0%
> 1,000,000	0%	0%	0%	0%	0%	0%	0%	0%

2019 Integrated *resource plan*

VOLUME II – APPENDICES M-R
OCTOBER 18, 2019

This 2019 Integrated Resource Plan Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Marengo Wind Project
Transmission Line
Electric Meter
Pavant III Solar Plant

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APPENDIX M – CASE STUDY FACT SHEETS

Case Fact Sheets Overview

This appendix documents the 2019 Integrated Resource Plan modeling assumptions used for the preferred portfolio, initial portfolio-development cases, C-Cases, CP-Cases, No Gas and Energy Gateway Cases, and Sensitivity Cases.

Case Fact Sheets - Overview

Preferred Portfolio Fact Sheet

The Preferred Portfolio Fact Sheet summarizes key assumptions and portfolio results for the Preferred Portfolio developed for the 2019 Integrated Resource Plan (IRP).

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-45 CNW	No Dave Johnston Wind Option	P-45CP	21,480	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Initial Portfolio-Development Fact Sheets

The following Initial Portfolio-Development Fact Sheets summarize key assumptions and portfolio results for each portfolio initially developed for the 2019 IRP.

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-01	Coal Study Benchmark	-	24,407	Base	Base	Med Gas, Med CO_2	Base	Segment F	2033
P-02	Regional Haze Reference	-	23,191	Base	Base	Med Gas, Med CO_2	Base	Segment F	2031
P-03	Regional Haze Intertemporal	-	21,951	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-04	Coal Study C-42	-	21,720	Base	Base	Med Gas, Med CO_2	Base	Segment F	2028
P-06	Gadsby Alternative Case	-	21,980	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-07	Gadsby Alternative Case	P-06	21,905	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-08	Naughton 3 Small Gas Conversion	P-03	21,979	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-09	Naughton 3 Large Gas Conversion	P-03	21,885	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-10	Naughton 3 Large Gas Conversion	P-04	21,723	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-11	Cholla 4 Retirement 2020	P-09	21,873	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-12	Cholla 4 Retirement 2025	P-06	21,854	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-13	Jim Bridger 1&2 SCRs	P-11	22,346	Base	Base	Med Gas, Med CO_2	Base	Segment F	2032
P-14	Naughton 1&2 and Jim Bridger 1-4 Retirement 2022	P-09	21,696	Base	Base	Med Gas, Med CO_2	Base	Segment F	2028
P-15	Retire All Coal by 2030	P28	22,132	Base	Base	Med Gas, Med CO_2	Base	Segment F	2027
P-16	Jim Bridger 1&2 Retirement 2022, No CO_2	P04	18,634	Base	Base	Med Gas, No CO_2	Base	None	2028
P-17	High CO_2	P-15	22,070	Base	Base	Med Gas, High CO_2	Base	Segment F	2028
P-18	Social Cost of Carbon	P-15	30,022	Base	Base	Low Gas, SCC CO_2	Base	Segment F	2028
P-19	Low Gas	P-04	20,882	Base	Base	Low Gas, Med CO_2	Base	Segment F	2023
P-20	High Gas	P-07	22,746	Base	Base	High Gas, Med CO_2	Base	Segment F	2029
P-28	Colstrip 3&4 Retirement 2025	P-11	21,805	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-30	Naughton 1&2 Retirement 2022	P-11	21,708	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029

P-31	Naughton 1&2 Retirement 2025	P-11	21,652	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-32	Naughton 1&2 Retirement 2025 with Gadsby 1-3 Retirement 2032	P-07	21,763	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-33	Jim Bridger 1&2 Retirement 2022	P-11	21,895	Base	Base	Med Gas, Med CO_2	Base	Segment F	2030
P-34	Jim Bridger 1&2 Retirement 2022, with Gadsby 1-3 Retirement 2020)	P-11	21,949	Base	Base	Med Gas, Med CO_2	Base	Segment F	2028
P-35	Jim Bridger 3&4 Retirement 2022	P-11	21,732	Base	Base	Med Gas, Med CO_2	Base	Segment F	2029
P-45	Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2038	P-31	21,593	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46	Jim Bridger 3&4 Retirement 2025	P-31	21,419	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53	Jim Bridger 1&2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032	P-31	21,438	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-54	Jim Bridger 2 Retirement 2024	P-31	21,708	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

C-Cases Portfolio-Development Fact Sheets

The following C-Cases Portfolio-Development Fact Sheets summarize key assumptions and portfolio results for each C-Case developed for the 2019 IRP.

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-31C	Naughton 1 & 2 Retirement 2025	P-11	21,639	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-36C	Jim Bridger 1-2 and Naughton 1&2 Retirement 2025	P-46	21,544	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-45C	Jim Bridger 1 & 2 Retirement 2023 and 2038	P-31	21,537	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46C	Jim Bridger 3 & 4 Retirement 2025	P-31	21,431	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46 J23C	Jim Bridger 3 & 4 Retirement 2023	P-46	21,385	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-47C	Jim Bridger 3 & 4 Retirement 2035	P-45	21,467	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-48C	Jim Bridger 3 & 4 Retirement 2033	P-45	21,482	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53C	Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032	P-31	21,450	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53 J23C	Jim Bridger 1 & 2 Retirement 2023	P-53	21,394	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-54C	Jim Bridger 2 Retirement 2024	P-54	21,591	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

Case Fact Sheets - Overview

CP-Cases Portfolio-Development Fact Sheets

The following CP-Cases Portfolio-Development Fact Sheets summarize key assumptions and portfolio results for each CP-Case developed for the 2019 IRP.

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-36CP	Jim Bridger 1-2 and Naughton 1-2 Retirement 2025	P-46	21,553	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-45CP	Jim Bridger 1-2 Retirement 2023 and 2038	P-31	21,480	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46CP	Jim Bridger 3 & 4 Retirement 2025	P-31	21,460	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-46CP J23C	Jim Bridger 3 & 4 Retirement 2023	P-46	21,402	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-47CP	Jim Bridger 3 & 4 Retirement 2035	P-45	21,469	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-48CP	Jim Bridger 3 & 4 Retirement 2033	P-45	21,457	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026
P-53CP	Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032	P-31	21,479	Base	Base	Med Gas, Med CO_2	Base	Segment F	2026

No Gas & Energy Gateway Fact Sheets

The following Fact Sheets summarize key assumptions and portfolio results for each No Gas and Energy Gateway Case developed for the 2019 IRP.

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-29	P-45CNW, No New Gas Option	P-45CNW	21,798	Base	Base	Med Gas, Med CO_2	Base	Segment F	-
P-29 PS	P-45CNW, No New Gas Option with pumped hydro storage	P-45CNW	21,970	Base	Base	Med Gas, Med CO_2	Base	Segment F	-

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
P-22	Energy Gateway Segment D.3	P-45CNW	21,886	Base	Base	Med Gas, Med CO_2	Base	Add Segment D.3	2030
P-23	Energy Gateway Segment D.1 and F	P-45CNW	22,151	Base	Base	Med Gas, Med CO_2	Base	Add Segments F and D.1	2026
P-25	Energy Gateway Segment D.3, E & H	P-45CNW	22,273	Base	Base	Med Gas, Med CO_2	Base	Add Segments D.3, Segment E, and H	2030
P-26	Energy Gateway Segment H	P-45CNW	21,579	Base	Base	Med Gas, Med CO_2	Base	Add Segment H	2028

Case Fact Sheets - Overview

Sensitivity Fact Sheets

The following Sensitivity Fact Sheets summarize key assumptions and portfolio results for each sensitivity being developed for the 2019 IRP.

Quick Reference Guide

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Gateway	1st Year of New Thermal
S-01	Low Load	P-45CNW	20,617	Low	Base	Base	Base	Base	2030
S-02	High Load	P-45CNW	22,602	High	Base	Base	Base	Base	2026
S-03	1 in 20 Load Growth	P-45CNW	21,634	1 in 20	Base	Base	Base	Base	2026
S-04	Low Private Generation	P-45CNW	21,758	Base	Low	Base	Base	Base	2029
S-05	High Private Generation	P-45CNW	21,371	Base	High	Base	Base	Base	2030
S-06	Business Plan	P-45CNW	21,695	Base	Base	Base	Base	Base	2028
S-07	No Customer Preference	P-45CNW	21,609	Base	Base	Base	Base	Base	2030
S-08	High Customer Preference	P-45CNW	21,636	Base	Base	Base	Base	Base	2030

Preferred Portfolio Fact Sheet

PORTFOLIO ASSUMPTIONS

Description

The preferred portfolio, P-45CNW, is a variant of P-45CP with all of the same assumptions and Planning and Risk Deterministic methodology applied except 620 MW Dave Johnston Wind in 2029 is removed.

PORTFOLIO SUMMARY

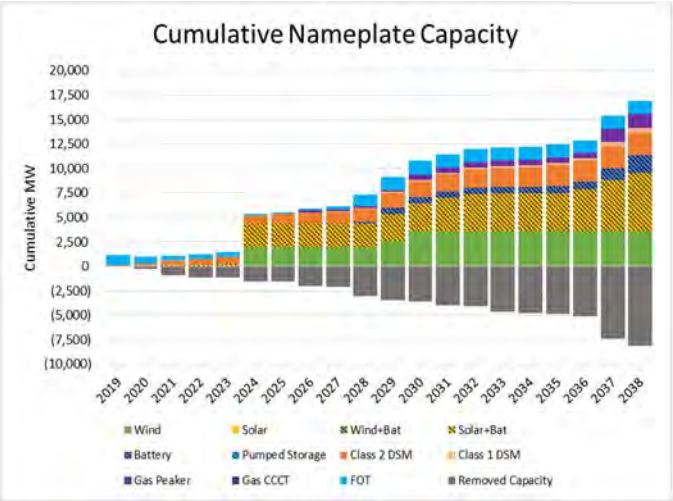
System Optimizer PVRR ($m) ***$21,480***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to – Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



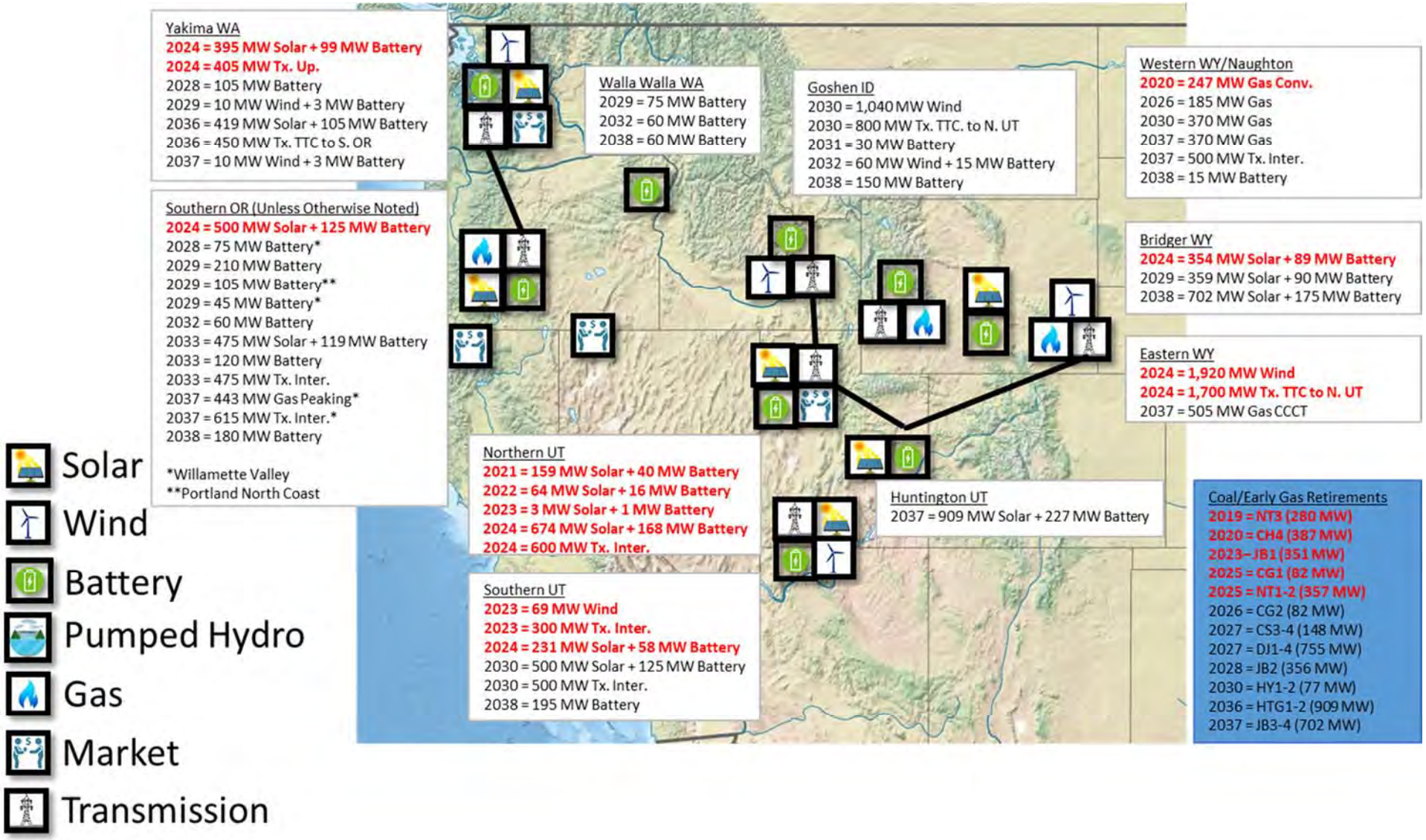
Retirement Assumptions

P-45CNW is the Preferred Portfolio case, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Retire 2019
Wyodak	Retire 2039

Portfolio: Preferred Portfolio (P-45CNW)

Case - P-45CNW (Preferred Portfolio)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P-01 serves as the benchmark portfolio to which the other Initial Portfolio-Development cases can be compared to determine their relative benefits or costs. It assumes scrubbers are added to Jim Bridger Unit 1 in 2022 & Unit 2 in 2021.

PORTFOLIO SUMMARY

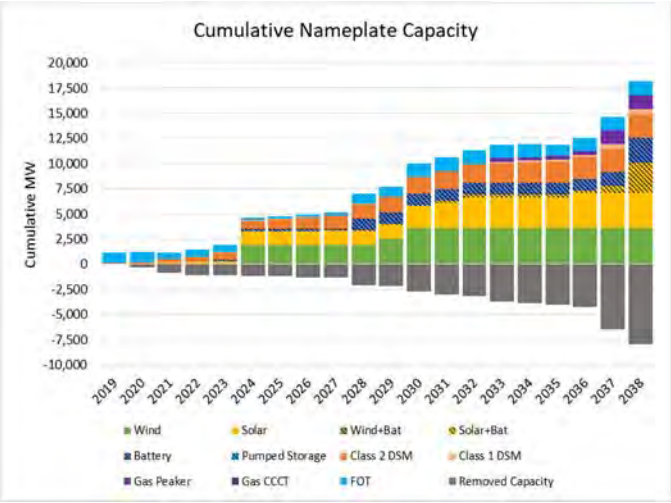
System Optimizer PVRR ($m) ***$23,191***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to – Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Walla Walla- to – Yakima	*2032*	*200*
Yakima- to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Retirement Assumptions

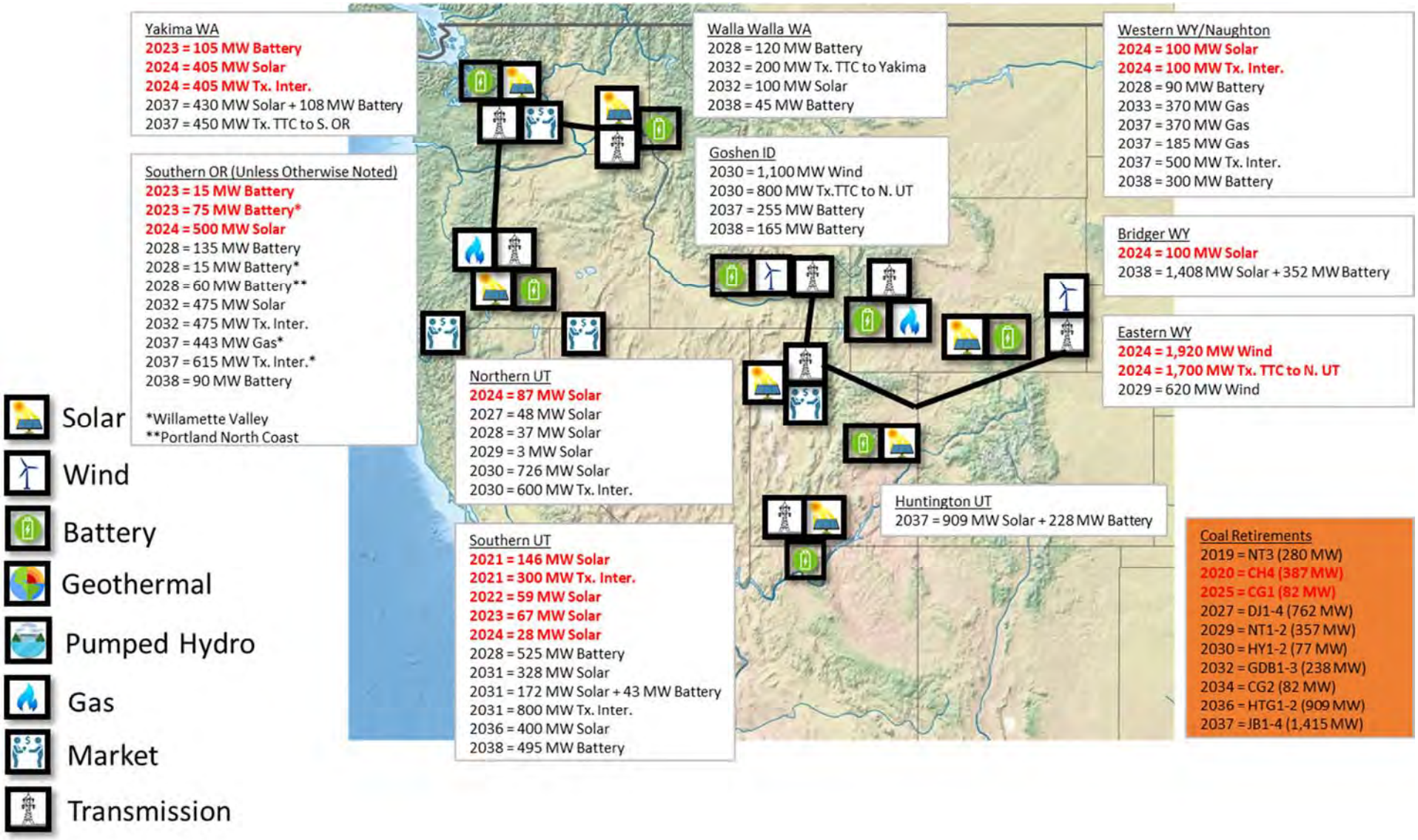
Initial portfolio-development case P-01 is the coal study case, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2046
Colstrip 4	Retire 2046
Craig 1	Retire 2025
Craig 2	Retire 2034
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	SCR 2022 & Retire 2037
Jim Bridger 2	SCR 2021 & Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Retire 2019
Wyodak	Retire 2039

SCR = selective catalytic reduction

Portfolio: Coal Study Benchmark (P-01)

Case - P-01 (Coal Study Benchmark)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Case P-02 is the Regional Haze Reference case which adds scrubbers between 2021 and 2023 to Hunter Units 1 & 2 and Huntington Units 1 & 2, in addition to the scrubbers in the base case for Jim Bridger Units 1 & 2, followed by each unit's expected retirement date. In addition, it retires Cholla Unit 4 in 2025 instead of 2020 in the base case, Colstrip Units 3 & 4 in 2027 instead of 2046 and Craig Unit 2 in 2026 instead of 2034.

PORTFOLIO SUMMARY

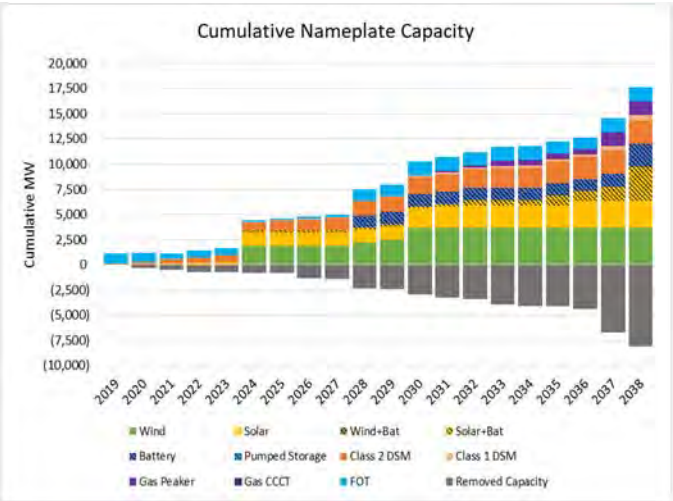
System Optimizer PVRR ($m) ***$23,191***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

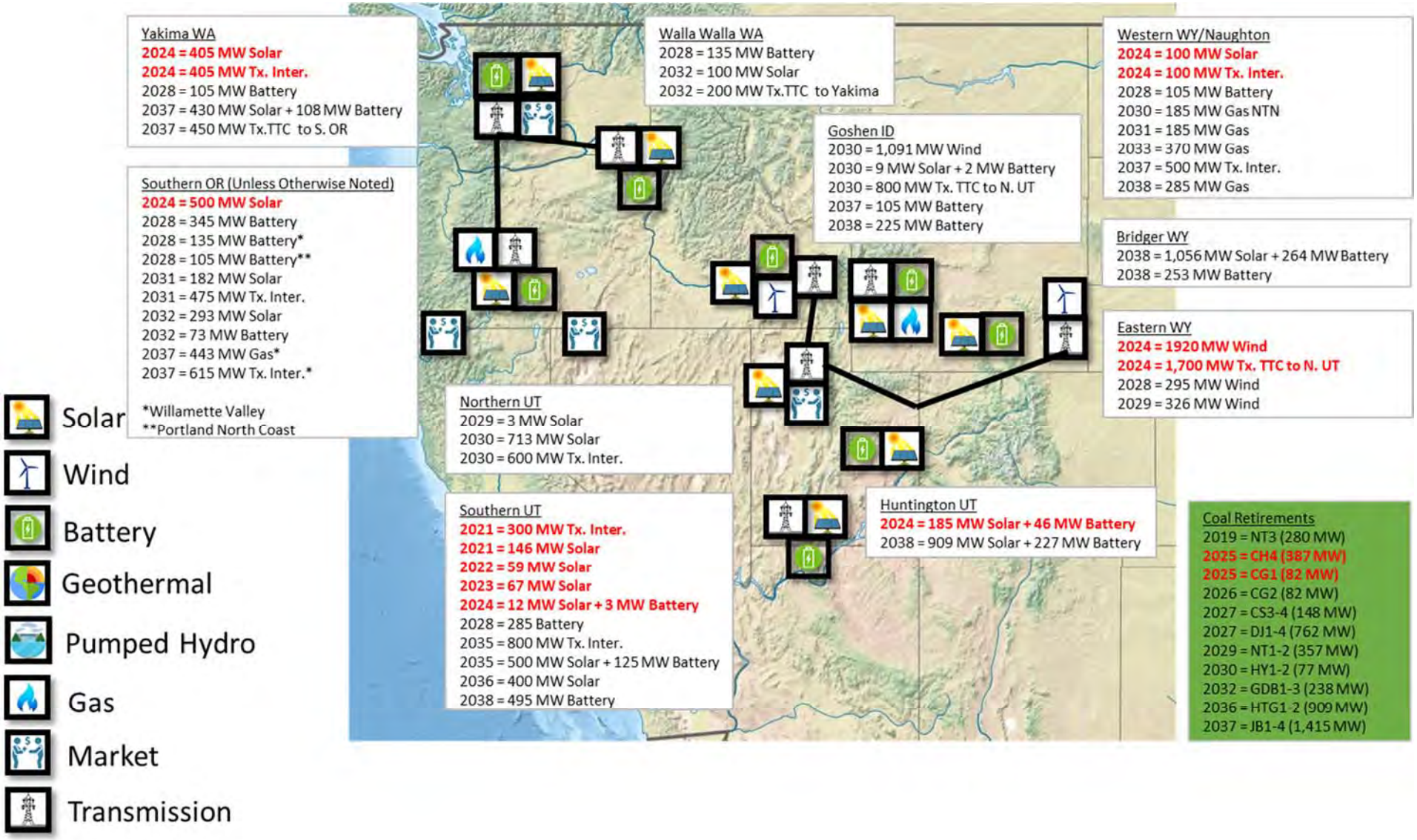
Initial portfolio-development case P-02 is the regional haze references case, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2025
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	SCR 2022 Retire 2042
Hunter 2	SCR 2022 Retire 2042
Hunter 3	Retire 2042
Huntington 1	SCR 2022 Retire 2036
Huntington 2	SCR 2023 Retire 2036
Jim Bridger 1	SCR 2022 Retire 2037
Jim Bridger 2	SCR 2021 Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Retire 2019
Wyodak	SCR 2024 Retire 2039

SCR = selective catalytic reduction

Portfolio: Regional Haze Reference (P-02)

Case - P-02 (Regional Haze Reference)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Similar to P-02, P-03 has all of the same retirement dates without the addition of the scrubbers on Hunter Units 1 & 2, Huntington Units 1 & 2 and Jim Bridger Units 1 & 2.

PORTFOLIO SUMMARY

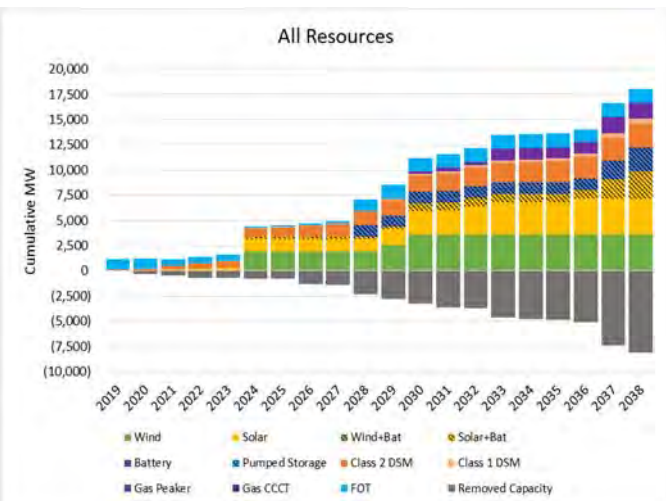
System Optimizer PVRR ($m) ***$21,951***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



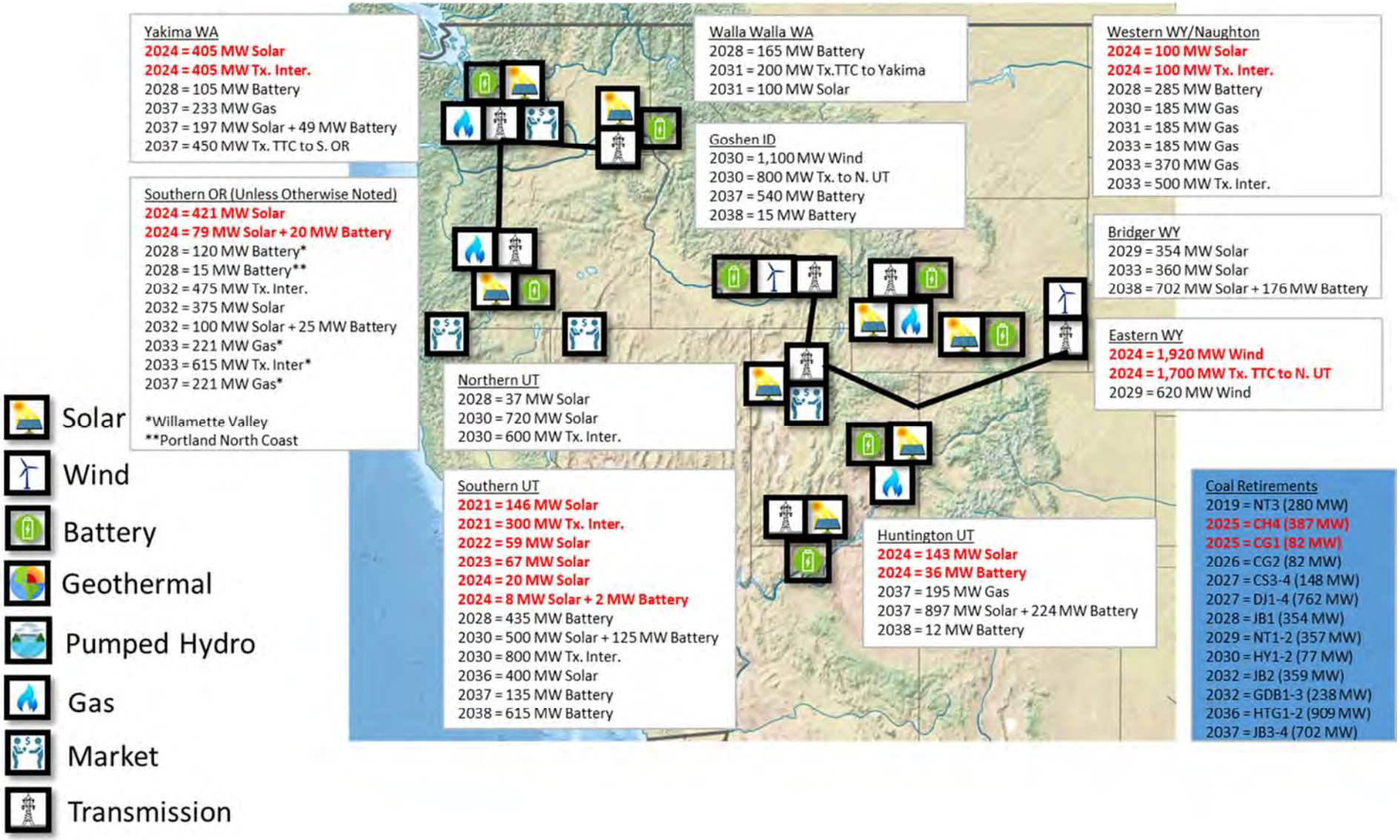
Retirement Assumptions

Initial portfolio-development case P-03 is the regional haze intertemporal case, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2025
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Retire 2019
Wyodak	Retire 2039

Portfolio: Regional Haze Intertemporal (P-03)

Case - P-03 (Regional Haze Intertemporal)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Similar to the P-01 benchmark, P-04 has the same retirement assumptions except Jim Bridger Units 1 & 2 retire in 2022 instead of 2037 and Naughton Units 1 & 2 also retire in 2022 instead of 2029. In addition, no units have scrubbers added.

PORTFOLIO SUMMARY

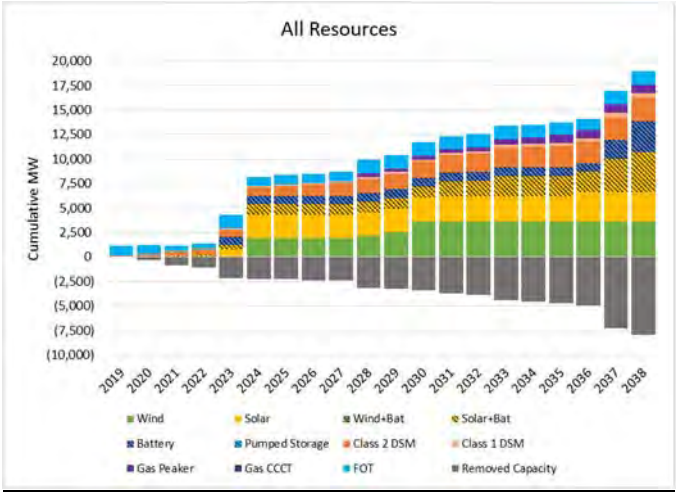
System Optimizer PVRR ($m) ***$21,720***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



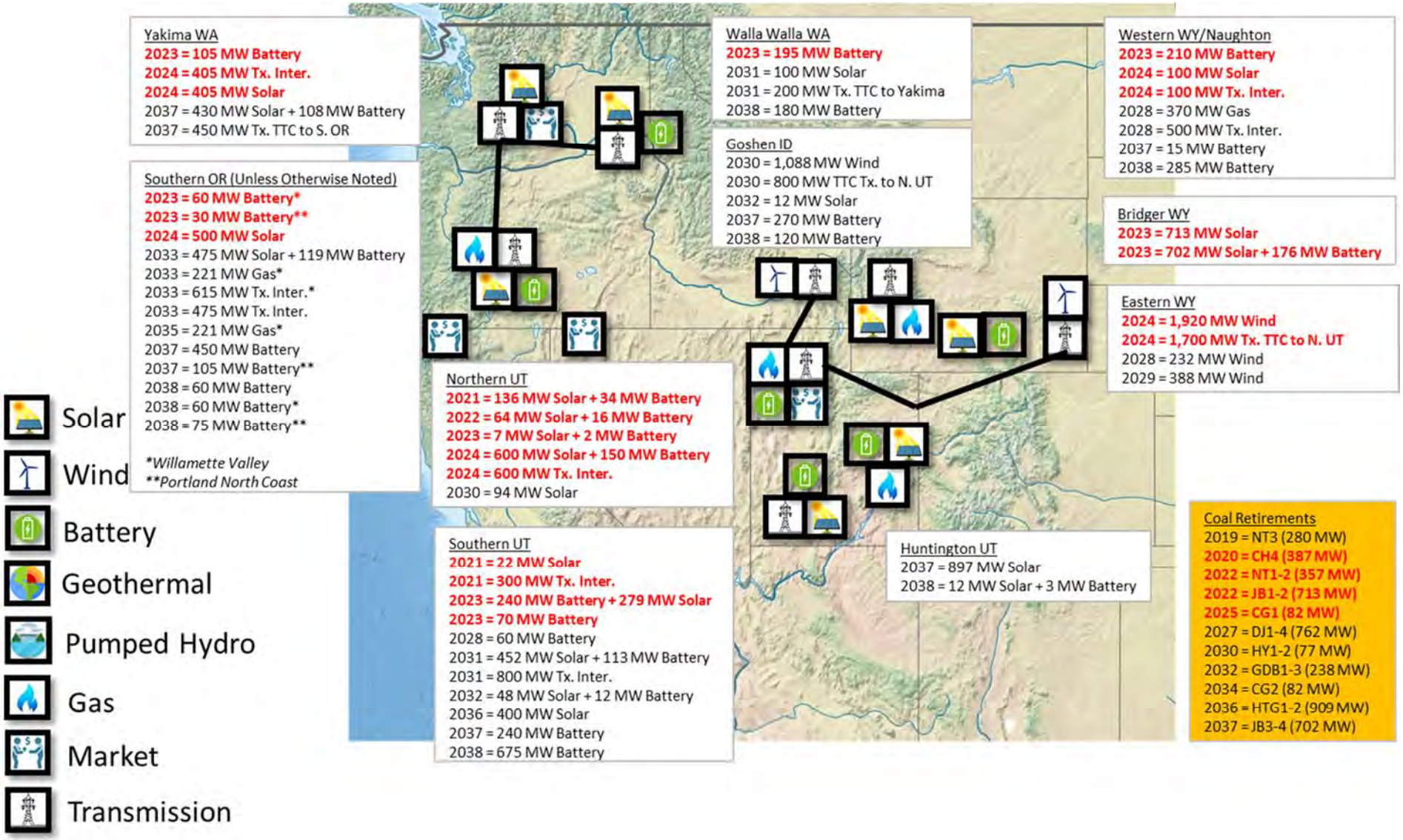
Retirement Assumptions

Initial portfolio-development case P-04 is P-01 with Jim Bridger Units 1 & 2 and Naughton Units 1 & 2 retiring in 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2046
Colstrip 4	Retire 2046
Craig 1	Retire 2025
Craig 2	Retire 2034
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Retire 2019
Wyodak	Retire 2039

Portfolio: Coal Study C-42 (P-04)

Case - P-04 (Coal Study C-42)



Portfolio: Gadsby Alternative Case (P-06)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Similar to P-04, P-06 has the same retirement assumptions except Colstrip Units 3 & 4 retire earlier in 2027 instead of 2047, Craig Unit 2 retires in 2025 instead of 2034, and Gadsby Units 1-3 retire in 2020 instead of 2032. In addition, Jim Bridger Unit 2 retires later, in 2032 instead of 2022 and Naughton Units 1 & 2 retire in 2029 instead of 2022. Meanwhile, Naughton 3 undergoes a larger gas conversion in 2020 followed by retirement in 2029.

PORTFOLIO SUMMARY

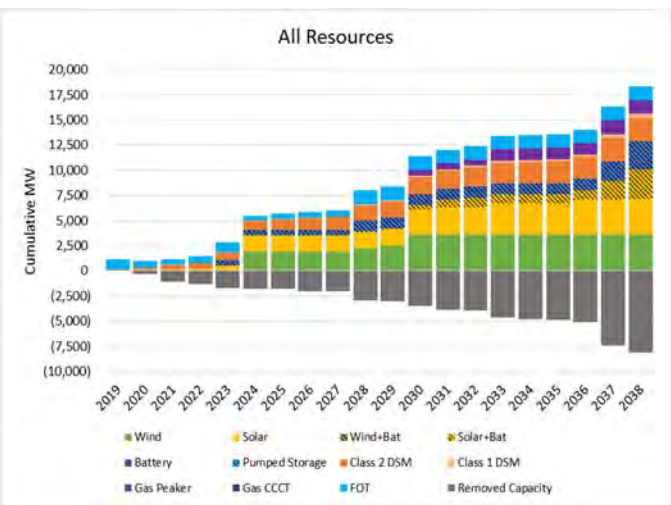
System Optimizer PVRR ($m) ***$21,980***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

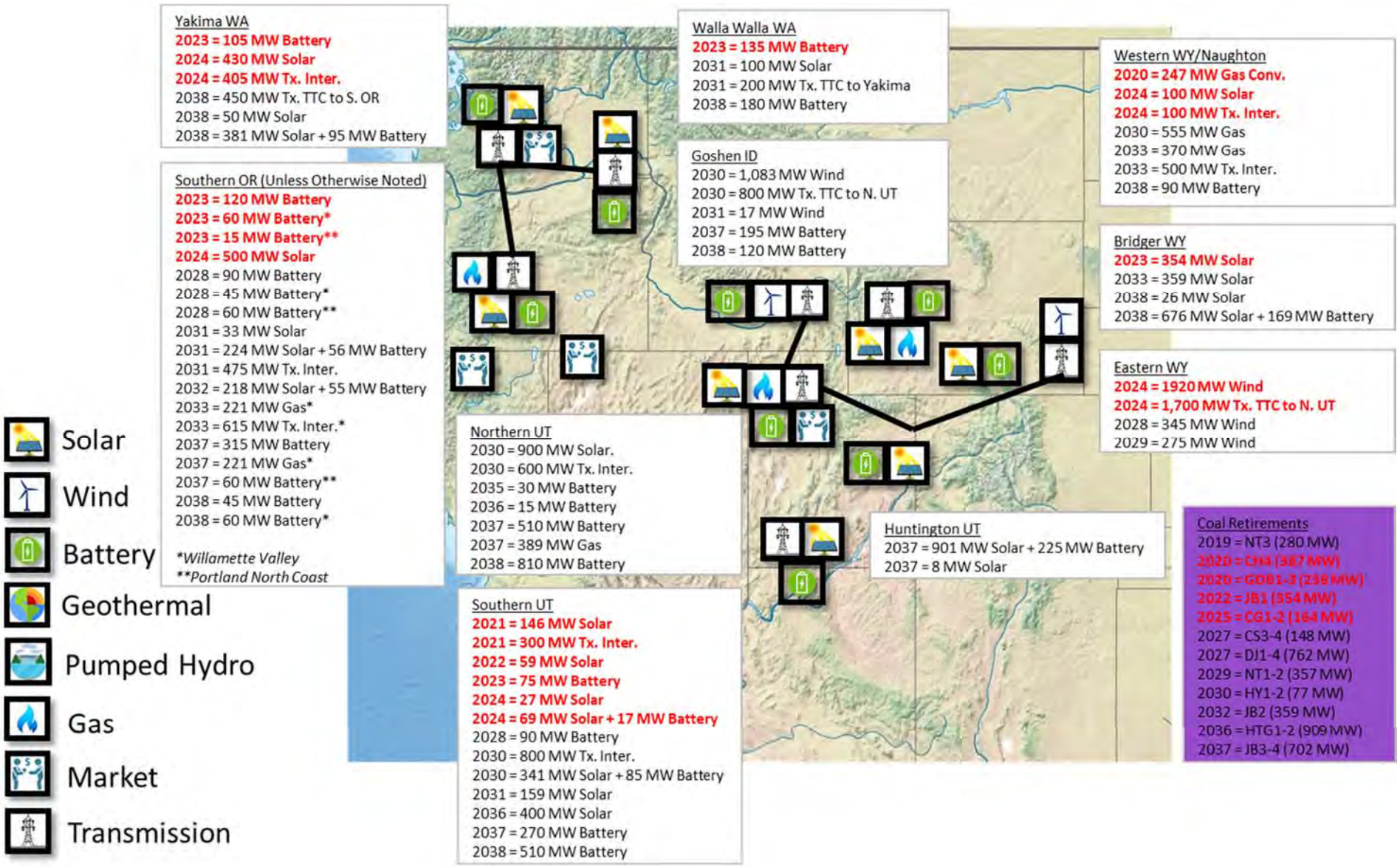
Initial portfolio-development case P-06 is Gadsby Units 1-3 alternative retirements. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2025
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Gadsby Alternative Case (P-06)

Case - P-06 (Gadsby Alternative Case)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-06, P-07 has all of the same retirement assumptions as well as gas conversion plans but tests retirement of Jim Bridger Unit 2 in 2028.

PORTFOLIO SUMMARY

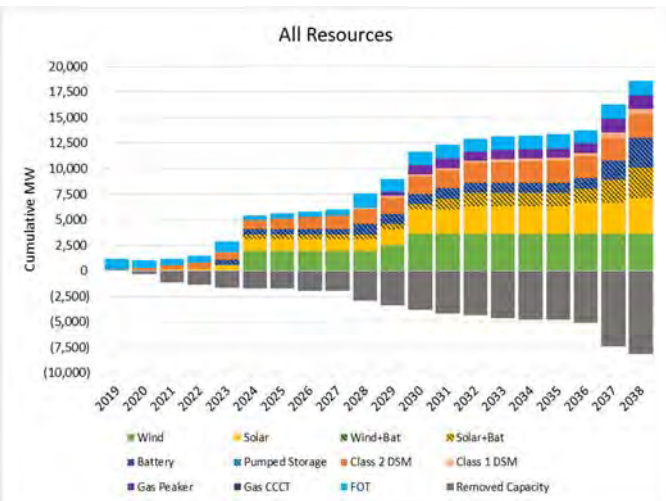
System Optimizer PVRR ($m) ***$21,905***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

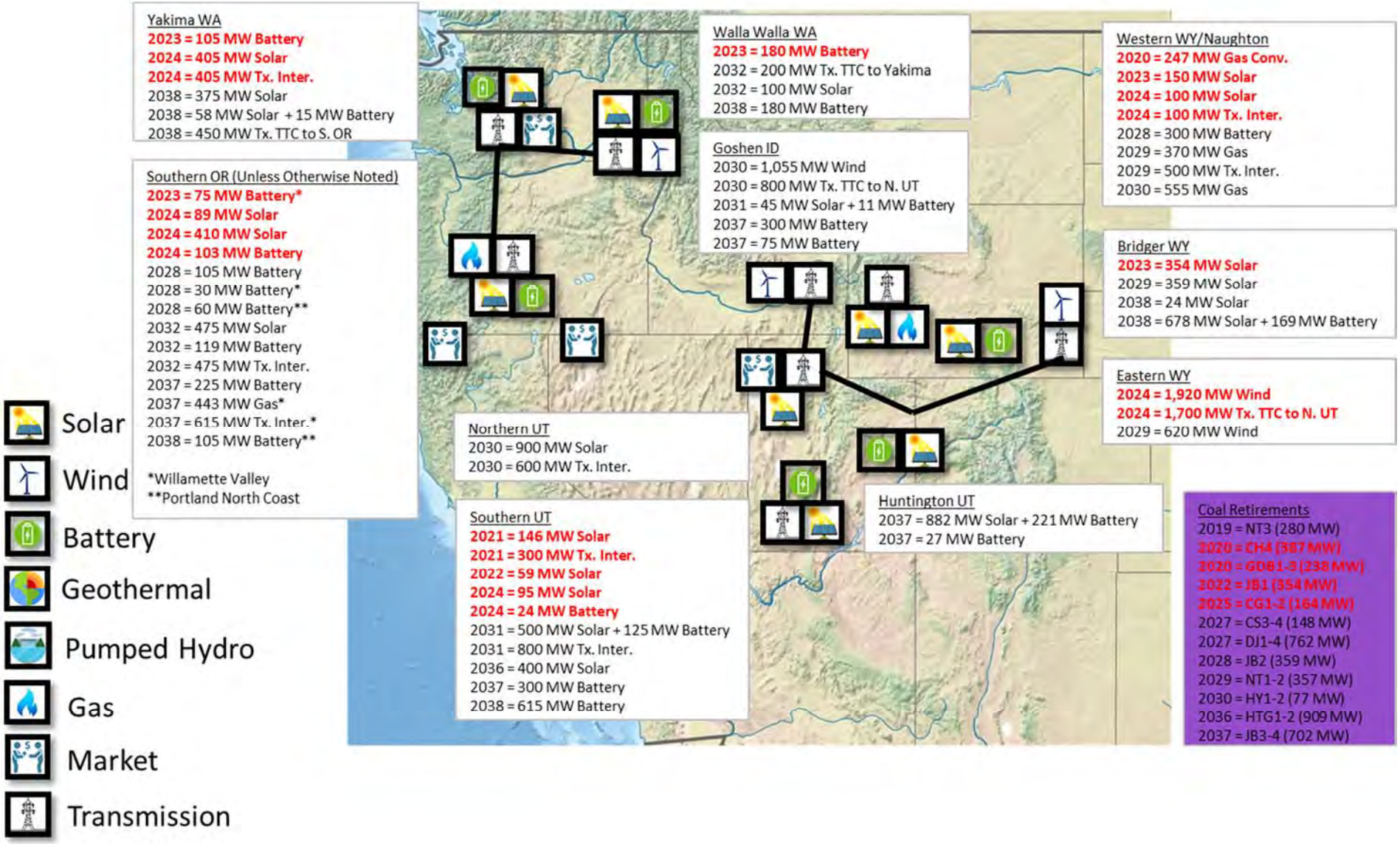
Initial portfolio-development case P-07 is P-06 with Jim Bridger Unit 2 retiring in 2028. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2025
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Gadsby Alternative Case (P-07)

Case - P-07 (Gadsby Alternative Case)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-03, P-08 has all of the same retirement assumptions except tests a small gas conversion on Naughton Unit 3 in 2022 with retirement still followed in 2029.

PORTFOLIO SUMMARY

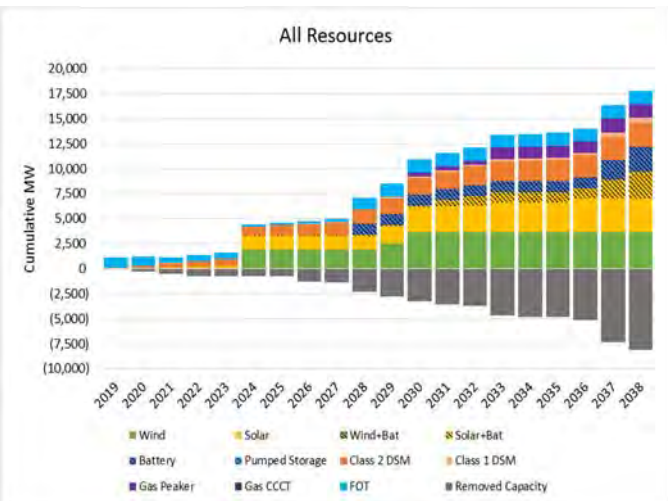
System Optimizer PVRR ($m) ***$21,979***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

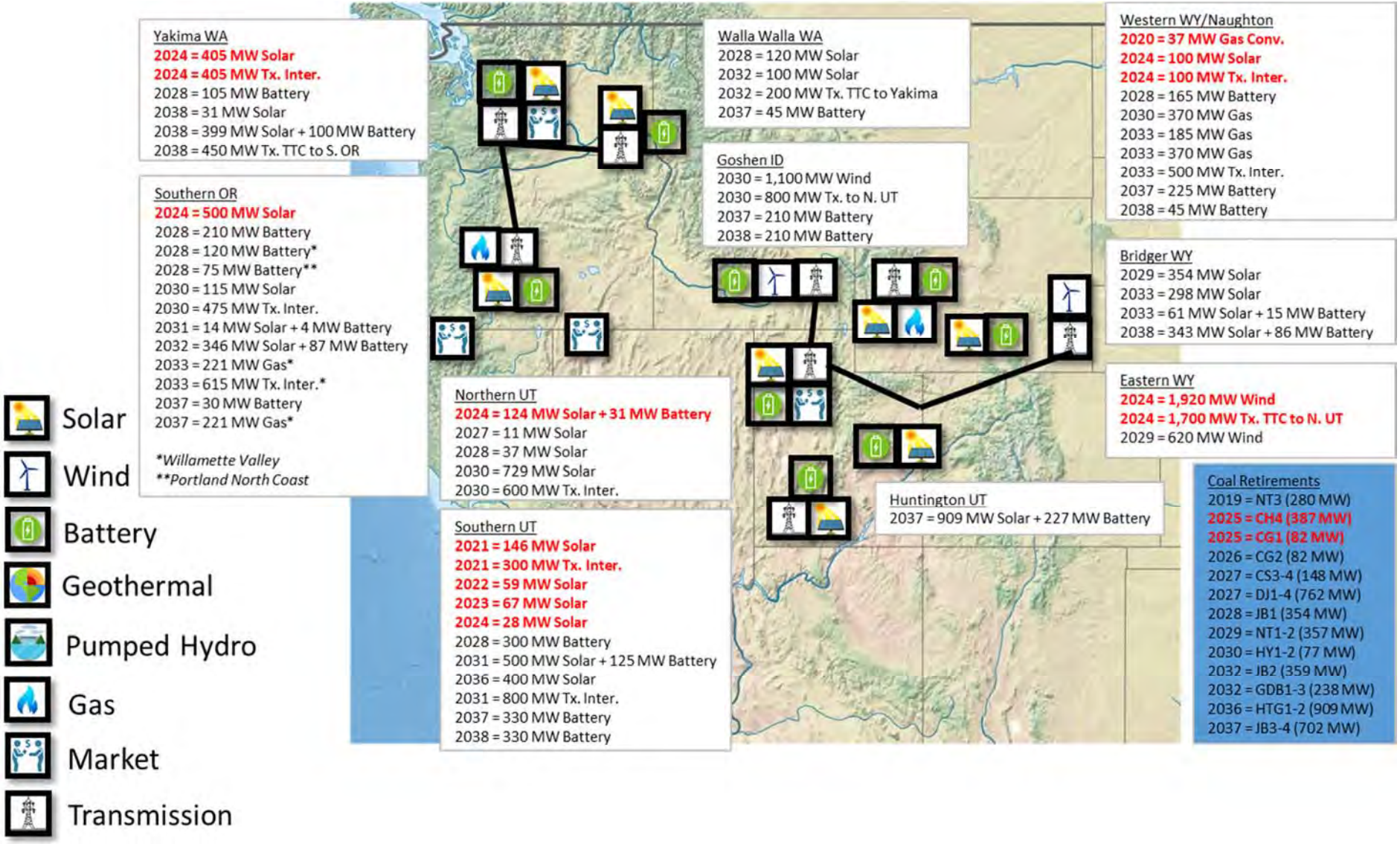
Initial portfolio-development case P-08 is P-03 with Naughton Unit 3 undergoing small gas conversion in 2020. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2025
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Sm. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 3 Small Gas Conversion (P-08)

Case - P-08 (Naughton 3 Small Gas Conversion)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-03, P-09 has all of the same retirement assumptions except tests a large gas conversion on Naughton Unit 3 in 2022 with retirement still followed in 2029.

PORTFOLIO SUMMARY

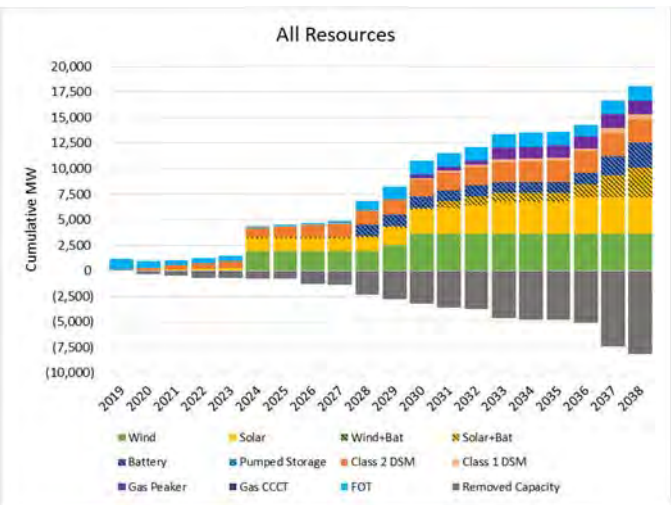
System Optimizer PVRR ($m) ***$21,885***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

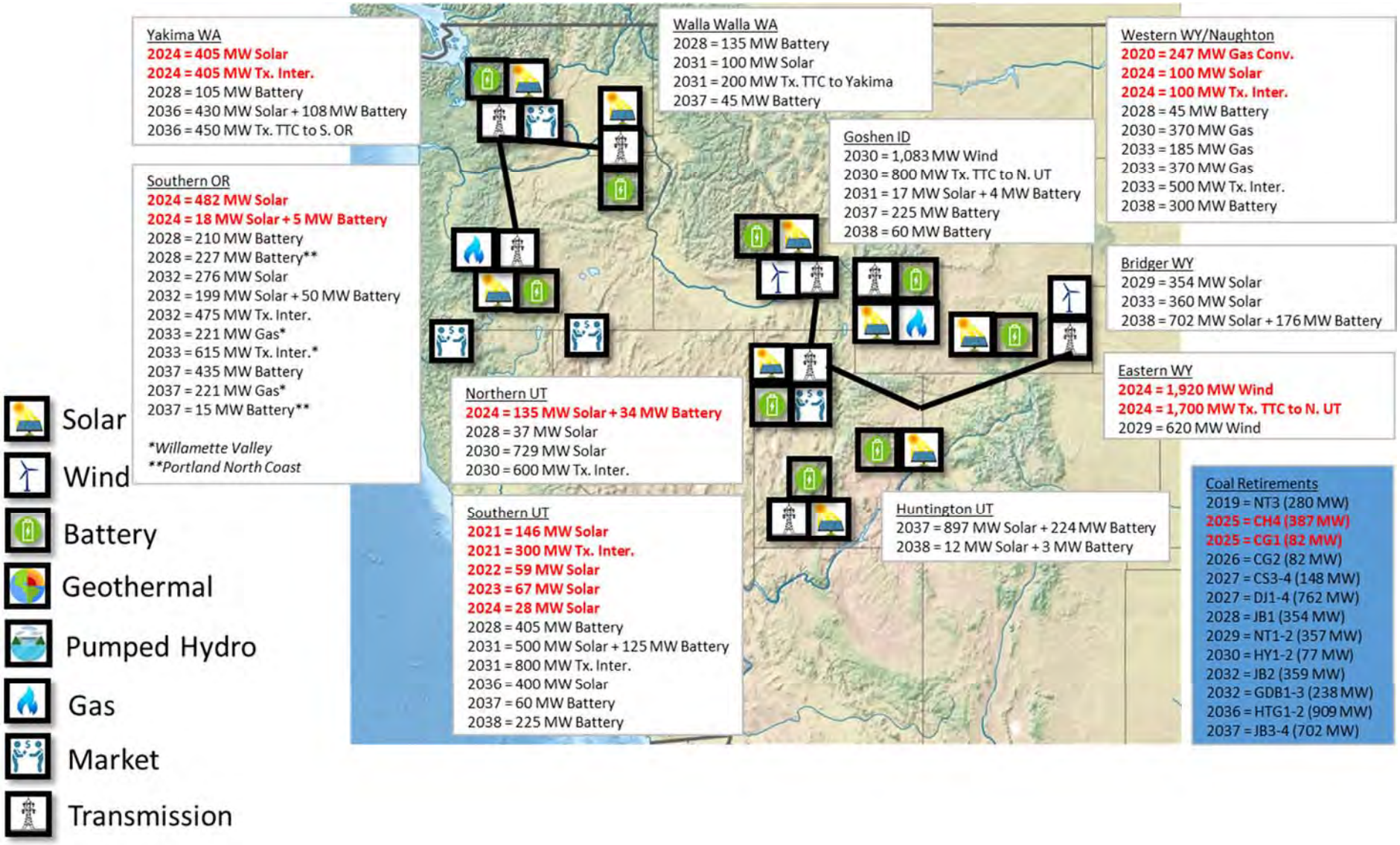
Initial portfolio-development case P-09 is P-03 with Naughton Unit 3 undergoing large gas conversion in 2020. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2025
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 3 Large Gas Conversion (P-09)

Case - P-09 (Naughton 3 Large Gas Conversion)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-04, P-10 has all of the same retirement assumptions except tests a large gas conversion on Naughton Unit 3 in 2020 with retirement still followed in 2029.

PORTFOLIO SUMMARY

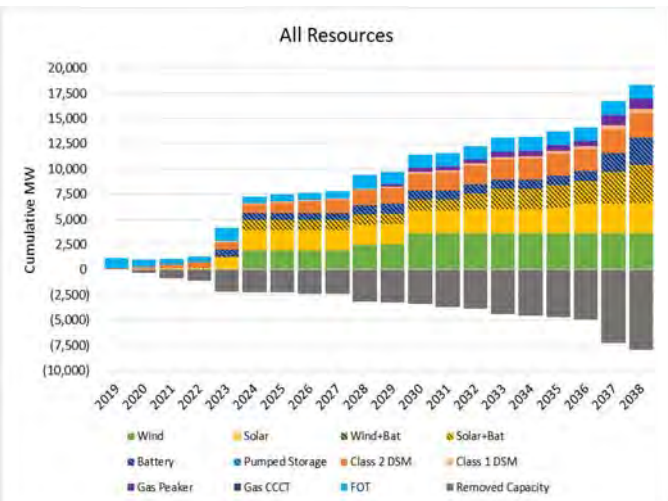
System Optimizer PVRR ($m) ***$21,723***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2035*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

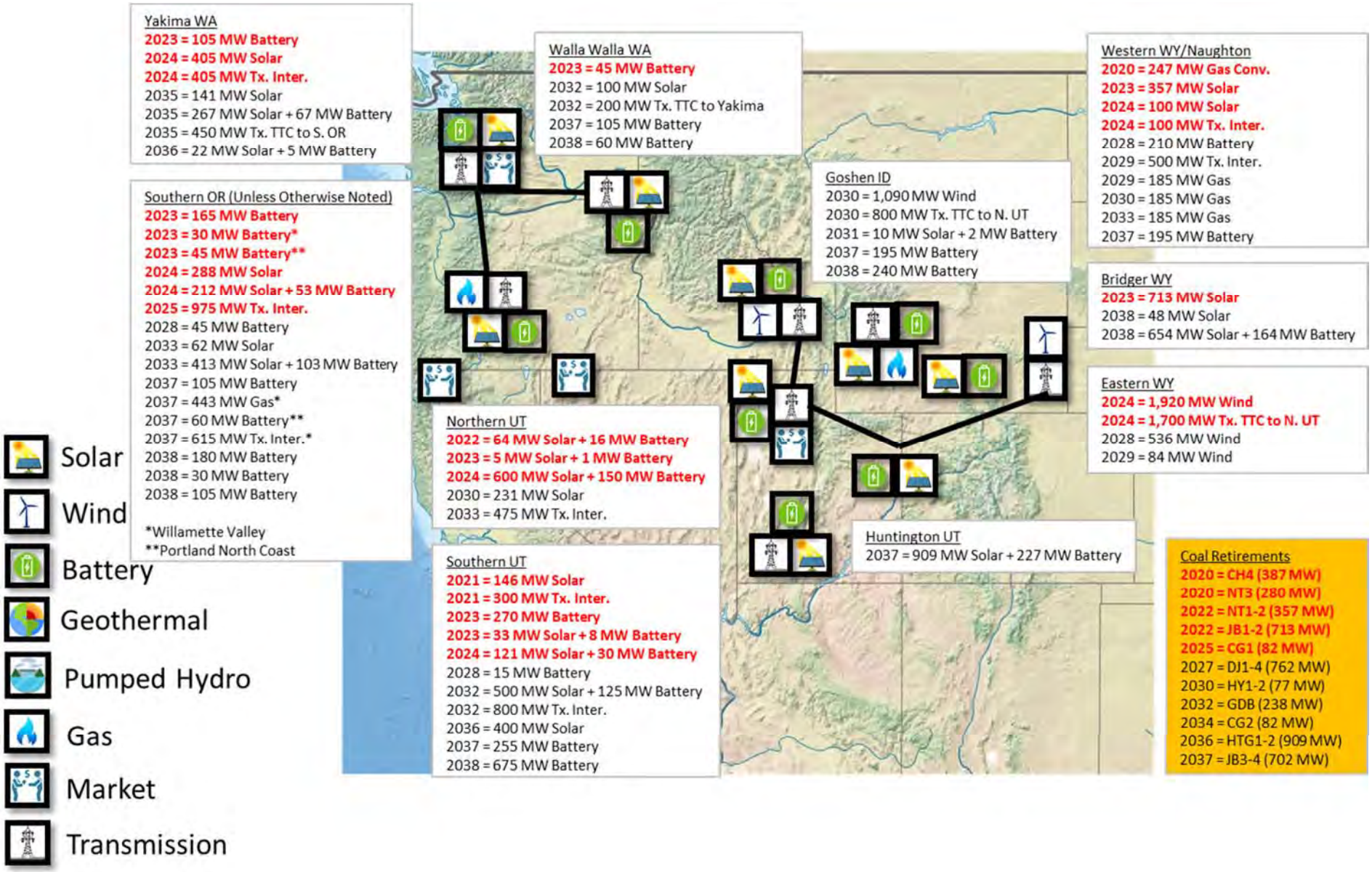
Initial portfolio-development case P-10 is P-04 with Naughton Unit 3 undergoing large gas conversion in 2020. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2046
Colstrip 4	Retire 2046
Craig 1	Retire 2025
Craig 2	Retire 2034
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 3 Large Gas Conversion (P-10)

Case - P-10 (Naughton 3 Large Gas Conversion)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-09, P-11 has all of the same retirement assumptions except tests retirement of Cholla Unit 4 in 2020 instead of 2025.

PORTFOLIO SUMMARY

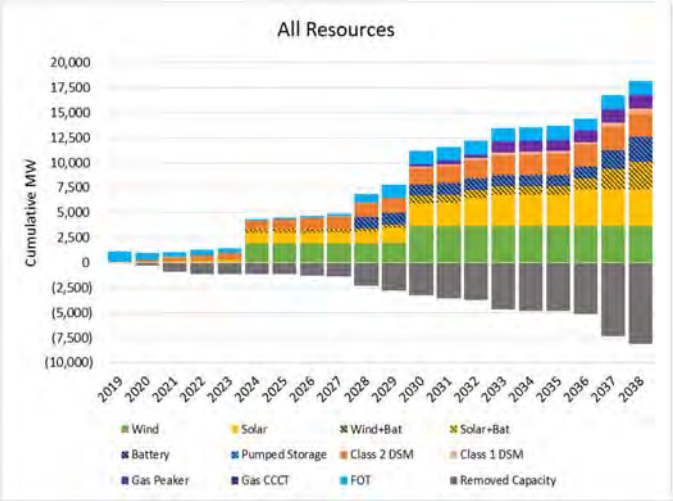
System Optimizer PVRR ($m) ***$21,873***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

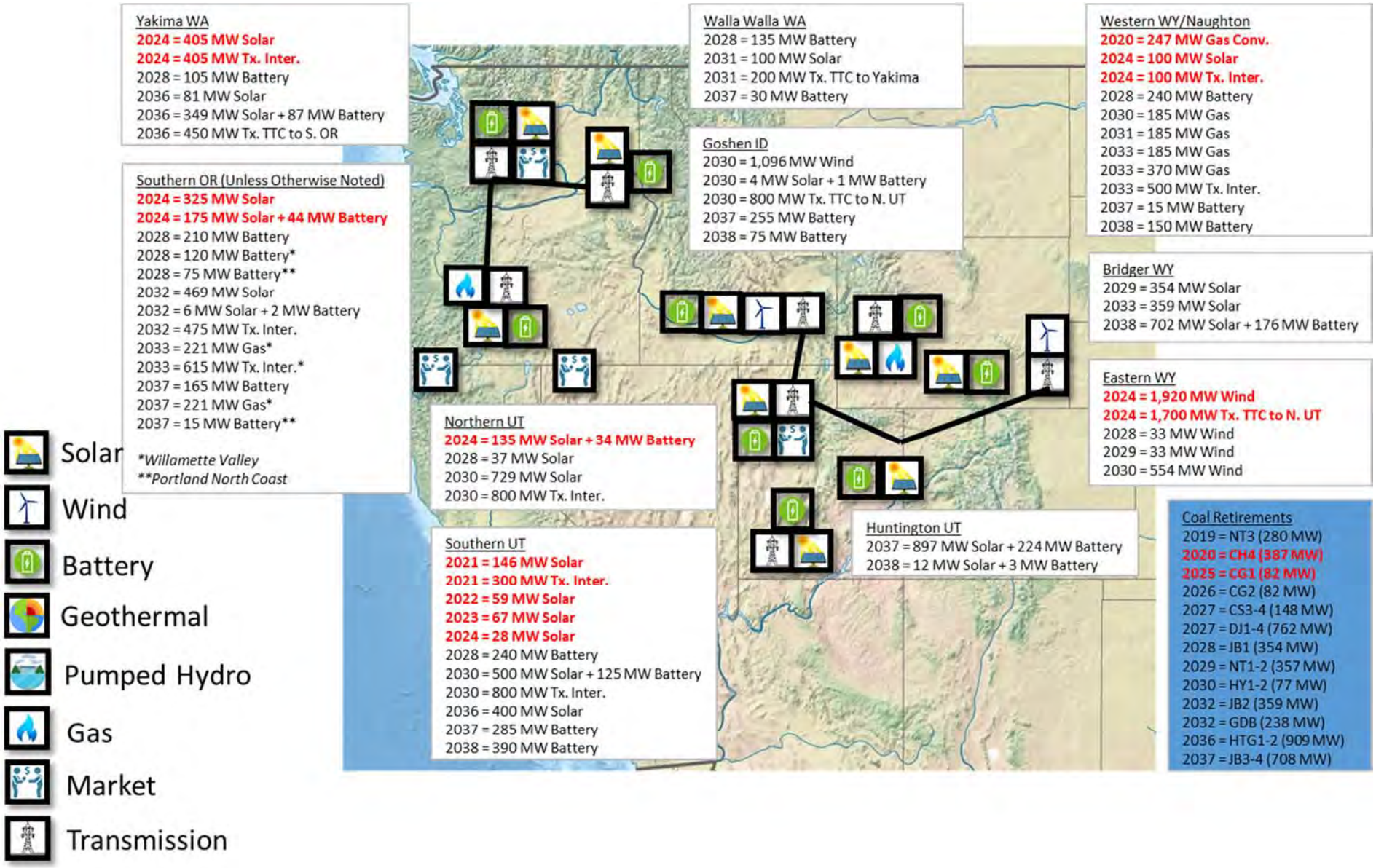
Initial portfolio-development case P-11 is P-09 with Cholla Unit 4 retirement accelerated to 2020. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Cholla 4 Retirement 2020 (P-11)

Case - P-11 (Cholla 4 Retirement 2020)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-06, P-12 has all of the same retirement assumptions except tests a Cholla Unit 4 retirement in 2025 instead of 2020.

PORTFOLIO SUMMARY

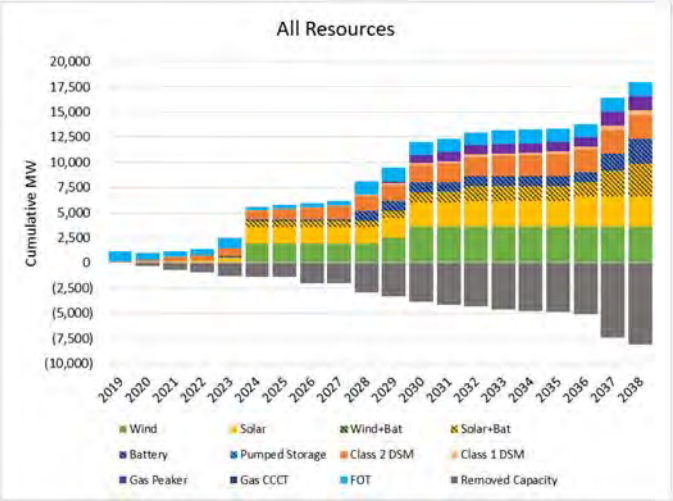
System Optimizer PVRR ($m) ***$21,854***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

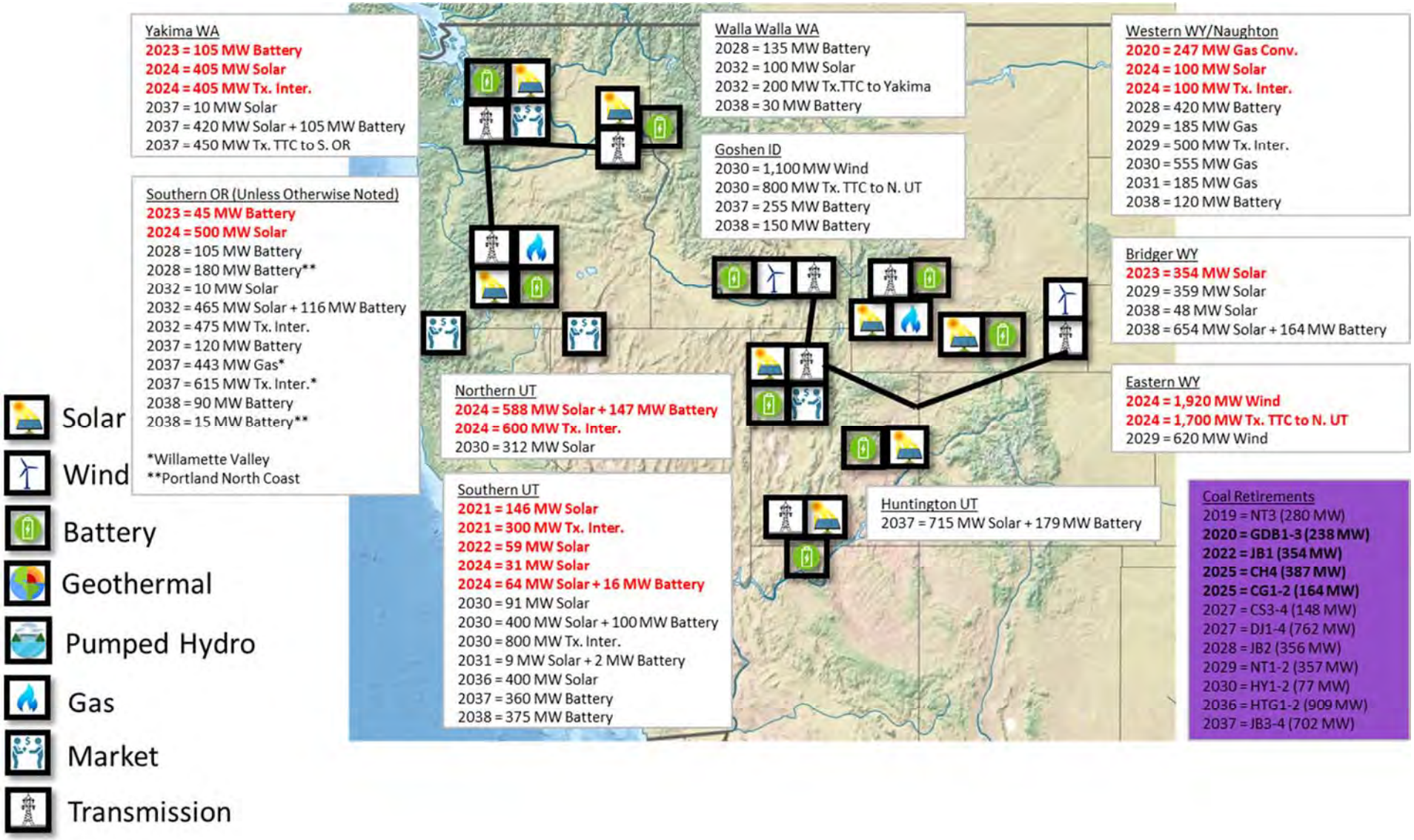
Initial portfolio-development case P-12 is P-06 with Cholla Unit 4 retiring in 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2025
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2025
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Cholla 4 Retirement 2025 (P-12)

Case - P-12 (Cholla 4 Retirement 2025)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, P-13 has all of the same retirement assumptions except tests the addition of scrubbers to Jim Bridger Unit 1 in 2022 followed by retirement in 2037 instead of 2028, and Jim Bridger Unit 2 in 2022 followed by retirement in 2037 instead of 2032.

PORTFOLIO SUMMARY

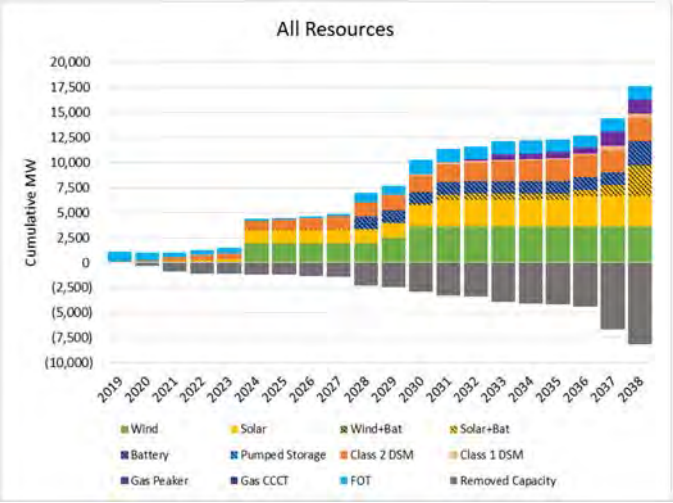
System Optimizer PVRR ($m) ***$22,346***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

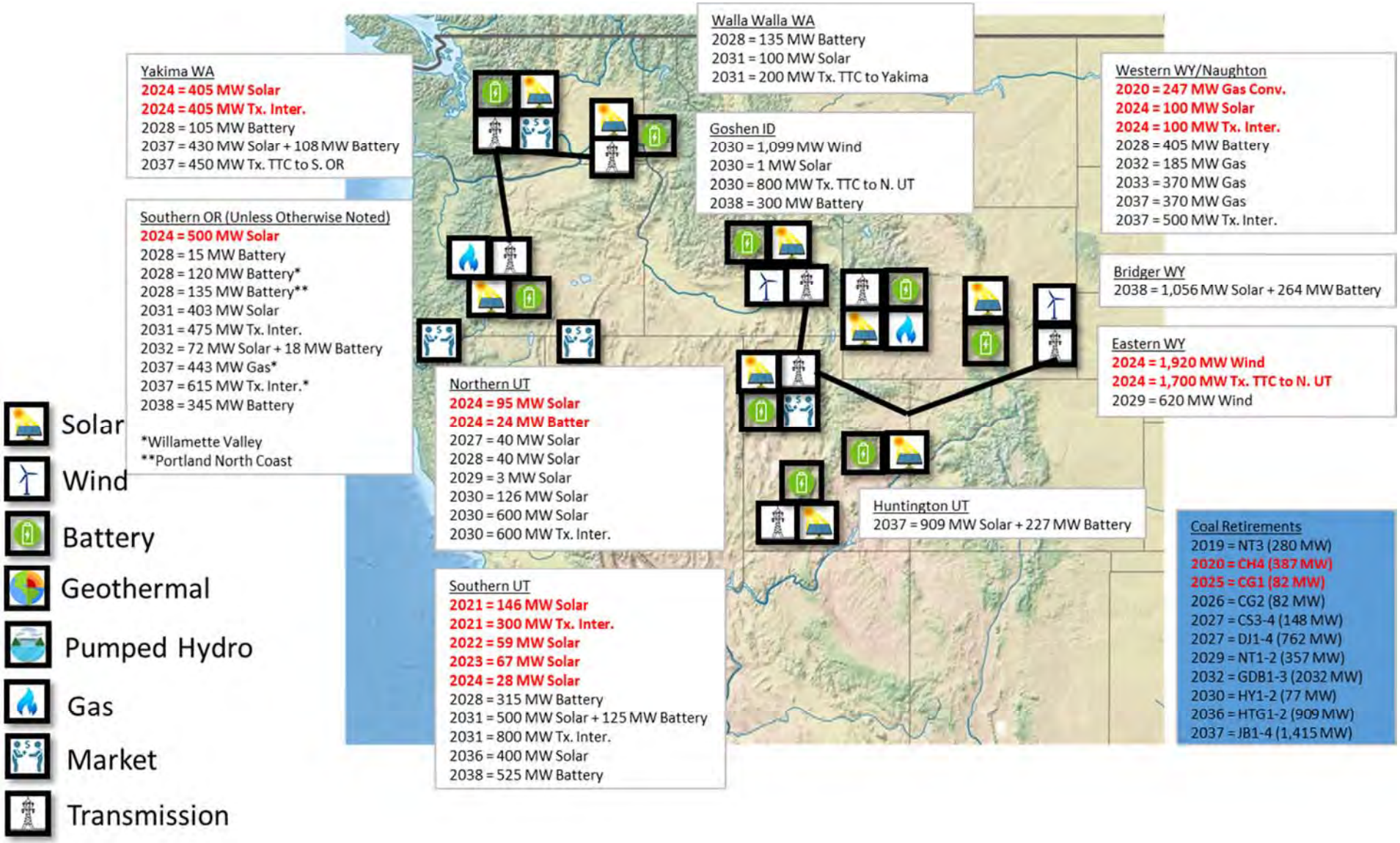
Initial portfolio-development case P-13 is P-11 with Jim Bridger Units 1 & 2 converting to SCRs. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2037
Jim Bridger 2	Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 SCRs (P-13)

Case - P-13 (Jim Bridger 1 & 2 SCRs)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-09, P-14 has all of the same retirement assumptions except retires Cholla in 2020 instead of 2025, all Jim Bridger Units in 2022 instead of Unit 1 in 2028, Unit 2 in 2032 and Units 3 & 4 in 2037. In addition, it retires Naughton Units 1 & 2 in 2022 instead of 2029.

PORTFOLIO SUMMARY

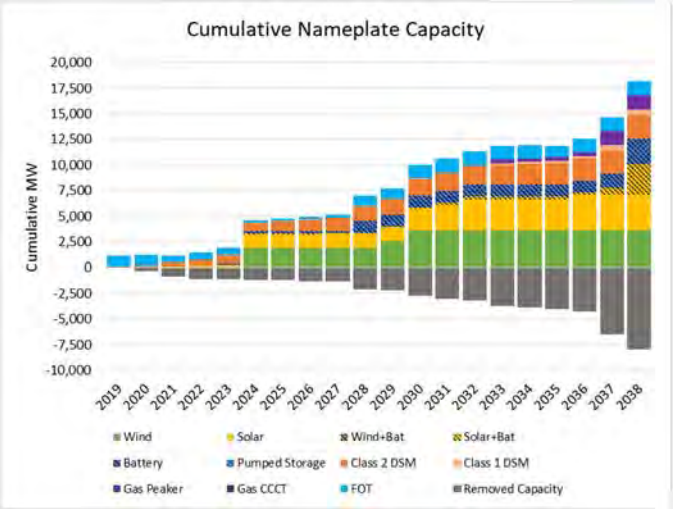
System Optimizer PVRR ($m) ***$21,696***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

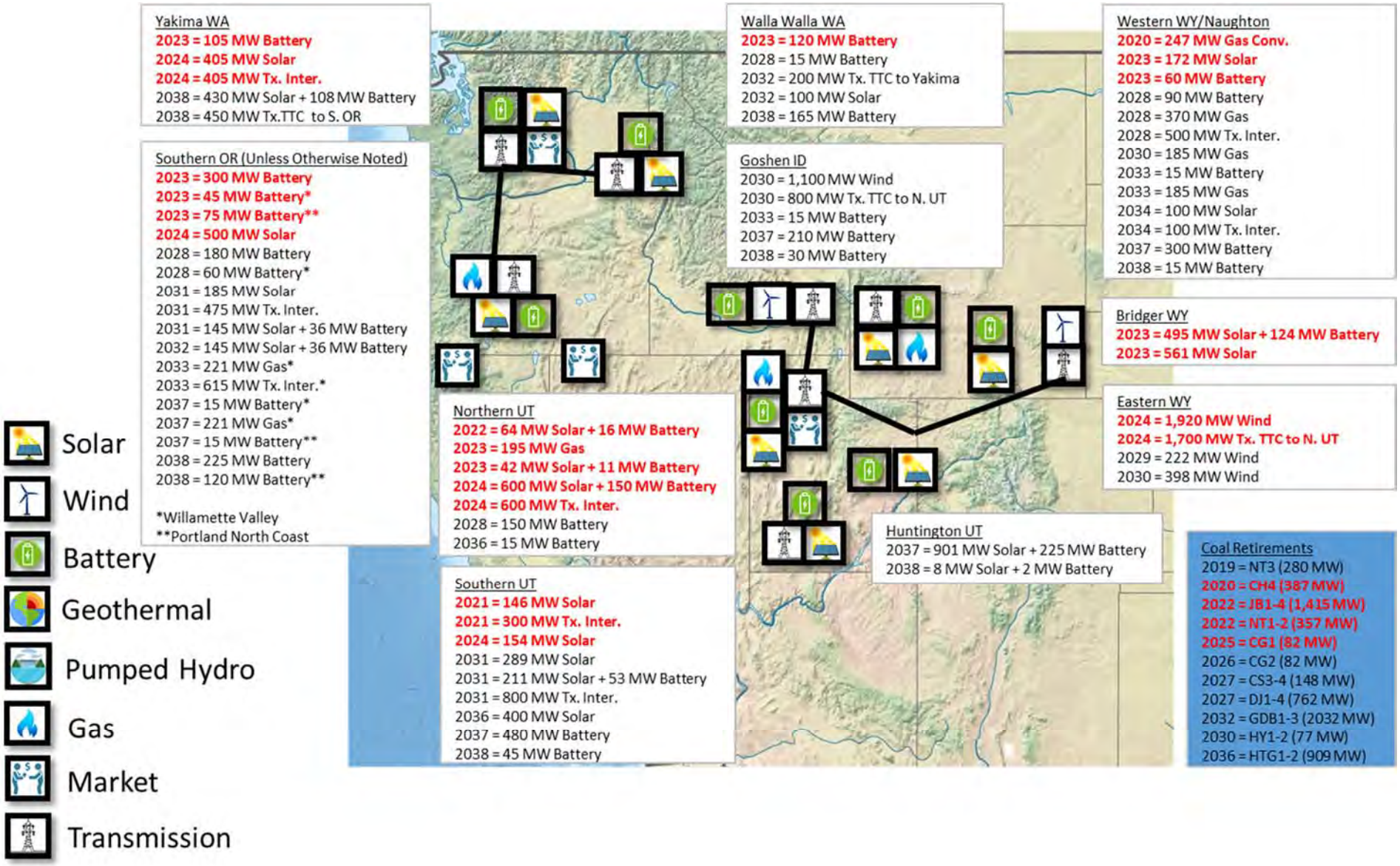
Initial portfolio-development case P-14 is P-11 with Naughton Units 1 & 2 and Jim Bridger Units 1-4 retiring in 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2022
Jim Bridger 4	Retire 2022
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 1 & 2 and Jim Bridger 1-4 Retirement 2022 (P-14)

Case - P-14 (Naughton 1-2 and Jim Bridger 1-4 Retired 2022)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

At stakeholder request, a variant of case P-28, P-15 was designed to economically retire all coal by 2030.

PORTFOLIO SUMMARY

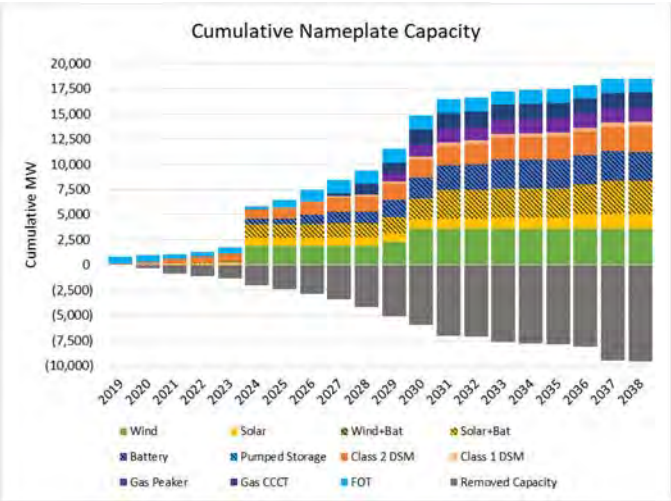
System Optimizer PVRR ($m) ***$22,132***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

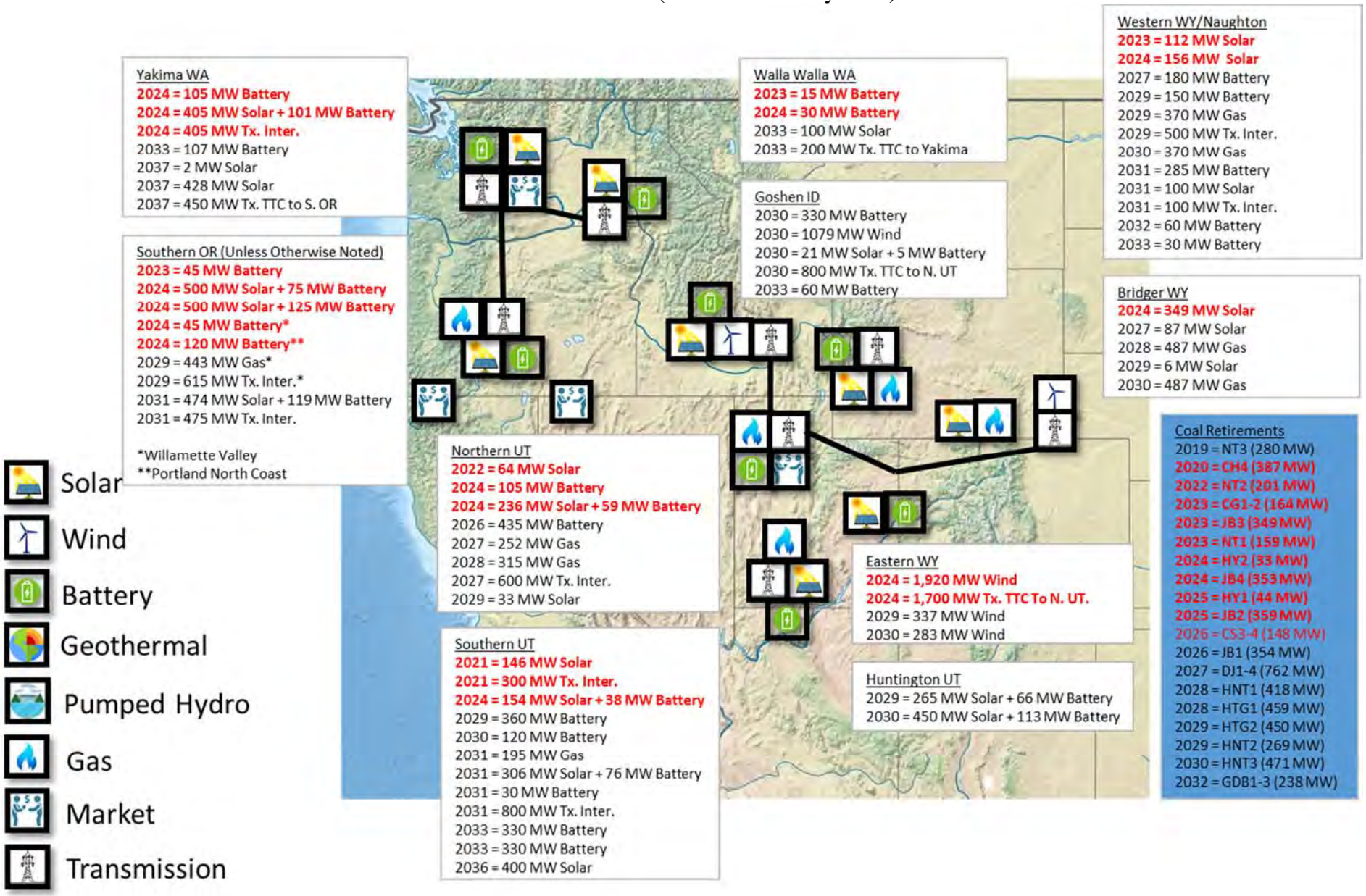
Initial portfolio-development case P-15a is P-28 with all coal retired by 2030. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2026
Colstrip 4	Retire 2026
Craig 1	Retire 2023
Craig 2	Retire 2023
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2025
Hayden 2	Retire 2024
Hunter 1	Retire 2028
Hunter 2	Retire 2029
Hunter 3	Retire 2030
Huntington 1	Retire 2028
Huntington 2	Retire 2029
Jim Bridger 1	Retire 2026
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2023
Jim Bridger 4	Retire 2024
Naughton 1	Retire 2023
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2030

GC = gas conversion

Portfolio: Retire All Coal by 2030 (P-15)

Case - P-15 (Retire All Coal by 2030)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-04, P-16 has all of the same retirement assumptions except was run with a low gas – no CO_2 price policy scenario through the System Optimizer and Planning and Risk.

PORTFOLIO SUMMARY

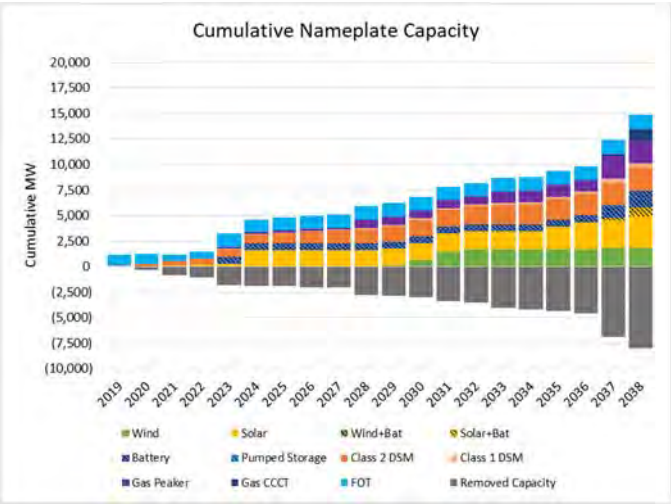
System Optimizer PVRR ($m) ***$18,634***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Goshen – to – Utah N, Expansion	*2032*	*800*
Yakima – to – S. Oregon, Expansion	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



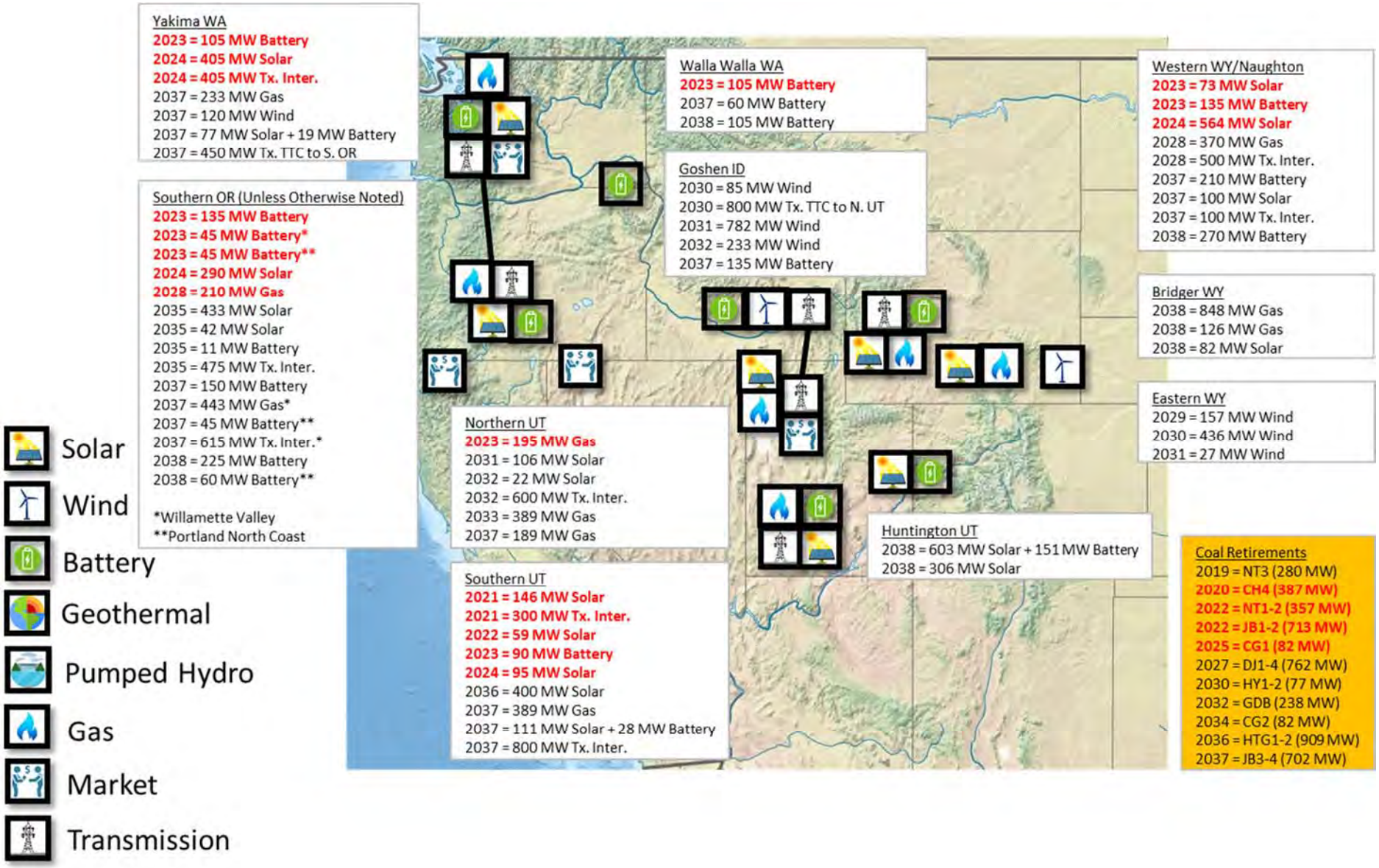
Retirement Assumptions

Initial portfolio-development case P-16 is P-04 with Jim Bridger Unit 1 & 2 Retired in 2022, with no CO_2. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2046
Colstrip 4	Retire 2046
Craig 1	Retire 2025
Craig 2	Retire 2034
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Retire 2019
Wyodak	Retire 2039

Portfolio: Jim Bridger 1 & 2 Retirement 2022, No CO_2 (P-16)

Case - P-16 (Jim Bridger 1 & 2 Retired 2022, No CO_2)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-15, P-17 has all of the same retirement assumptions except was run with a medium gas – high CO_2 price policy scenario through the System Optimizer and Planning and Risk.

PORTFOLIO SUMMARY

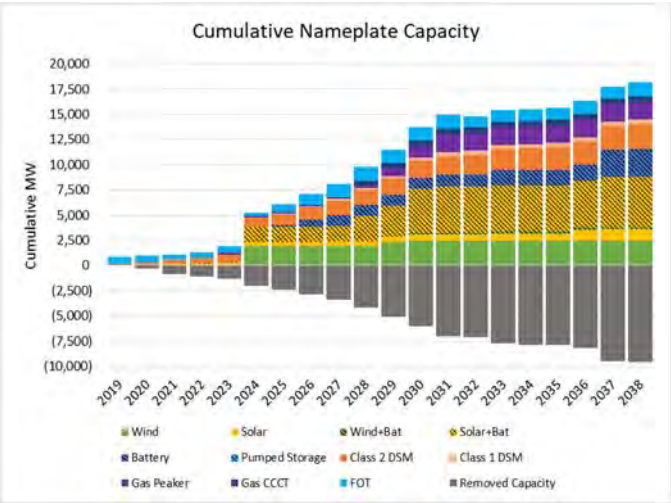
System Optimizer PVRR ($m) ***$22,070***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2033*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

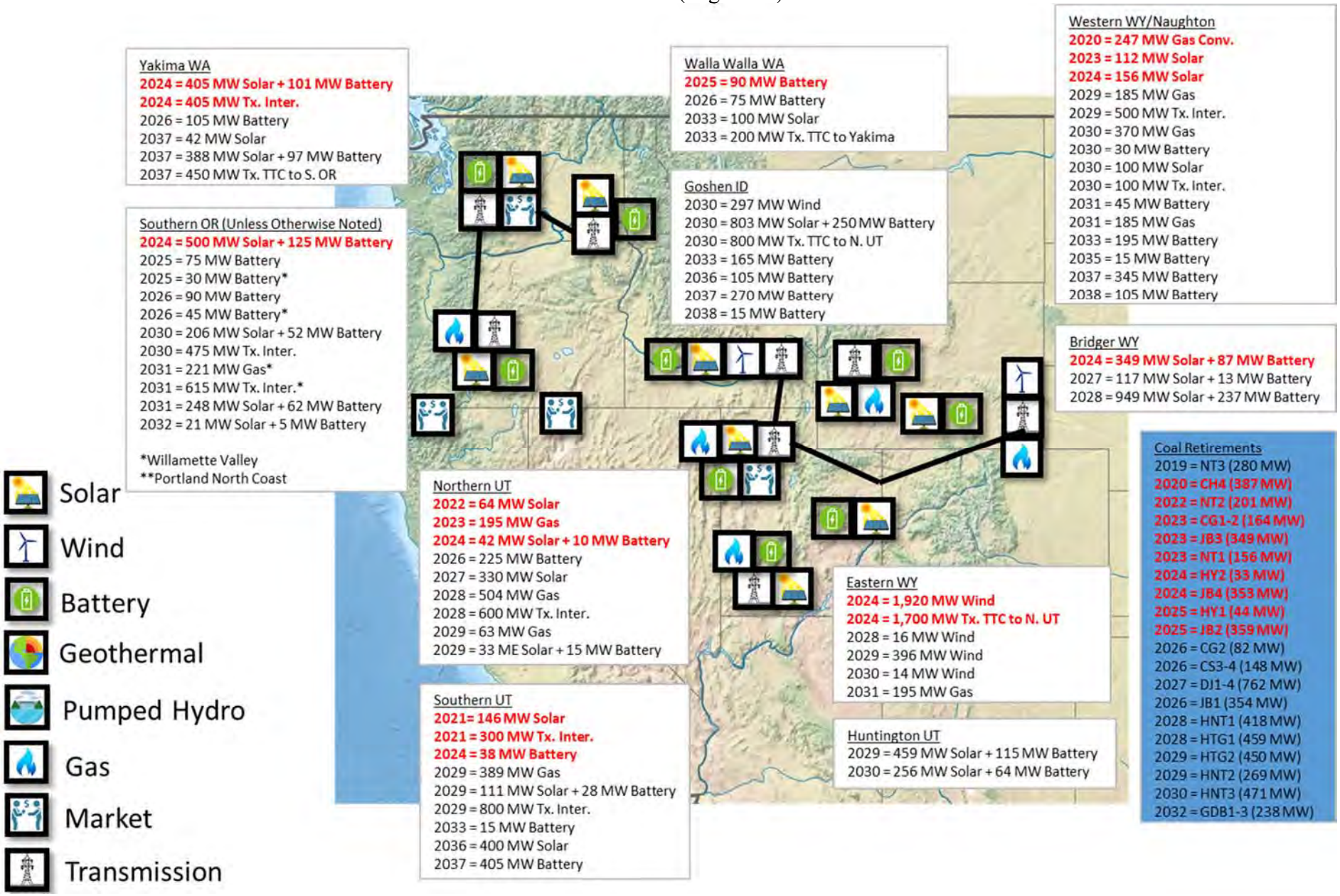
Initial portfolio-development case P-17 is P-15 with high CO_2, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2026
Colstrip 4	Retire 2026
Craig 1	Retire 2023
Craig 2	Retire 2023
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2025
Hayden 2	Retire 2024
Hunter 1	Retire 2028
Hunter 2	Retire 2029
Hunter 3	Retire 2030
Huntington 1	Retire 2028
Huntington 2	Retire 2029
Jim Bridger 1	Retire 2026
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2023
Jim Bridger 4	Retire 2024
Naughton 1	Retire 2023
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2030

GC = gas conversion

Portfolio: High CO_2 (P-17)

P-17 (High CO_2)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-15, P-18 has all of the same retirement assumptions except was run with a medium gas – social cost of carbon price policy scenario through the System Optimizer and Planning and Risk.

PORTFOLIO SUMMARY

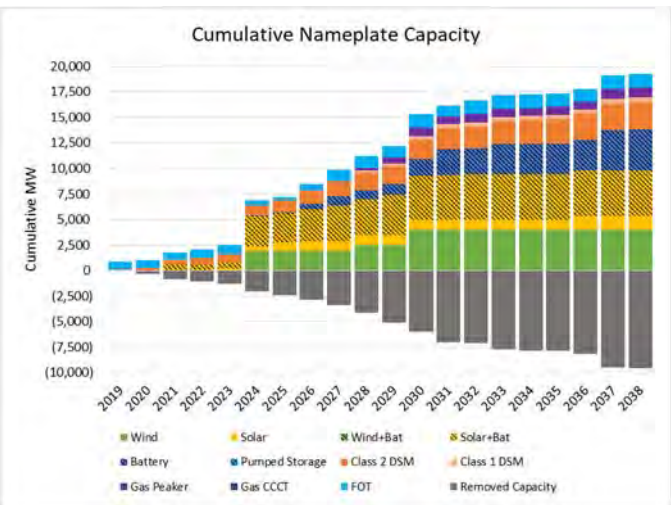
System Optimizer PVRR ($m) ***$30,022***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2030*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

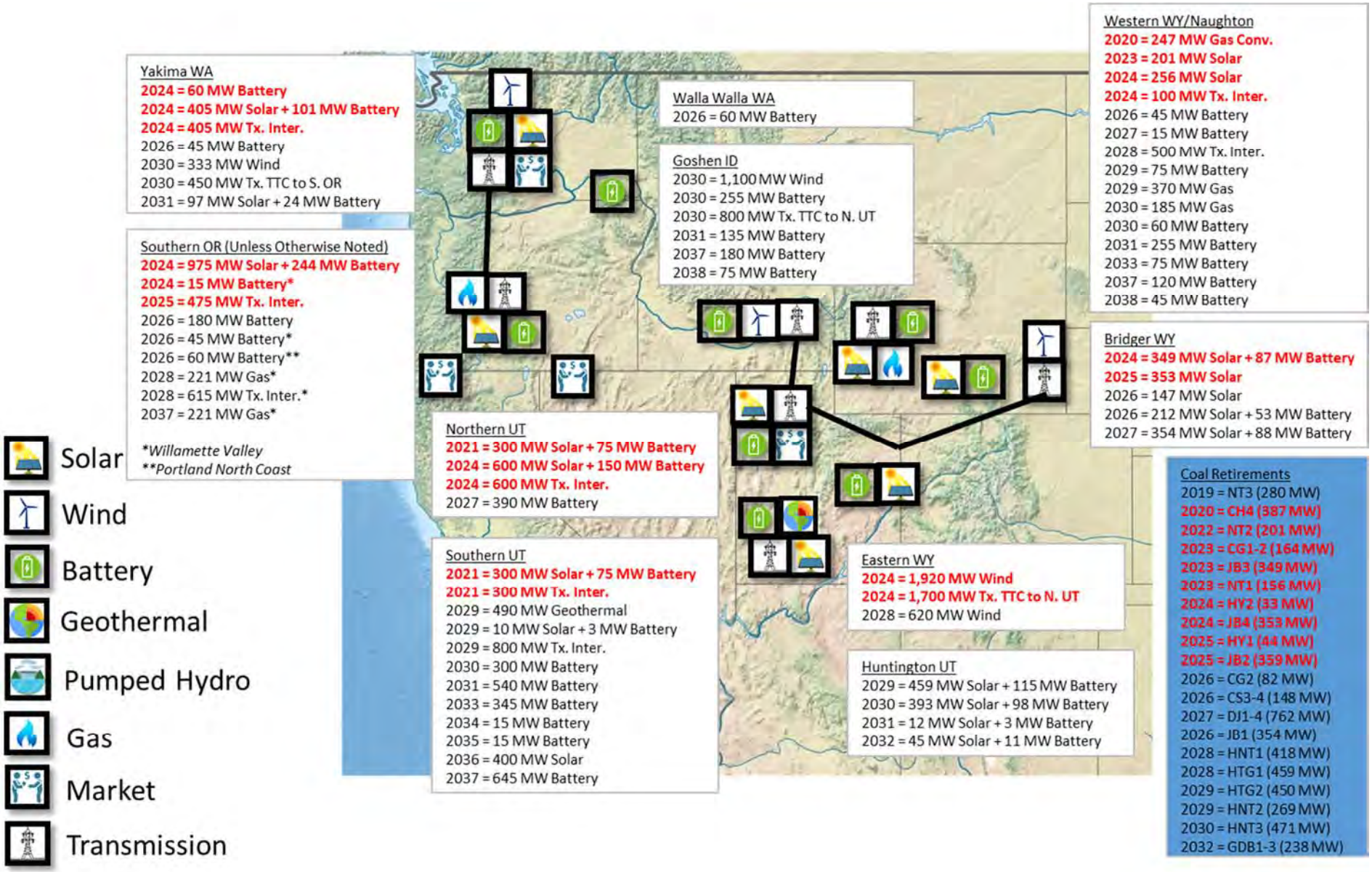
Initial portfolio-development case P-18 is P-15, social cost of carbon, and the retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2026
Colstrip 4	Retire 2026
Craig 1	Retire 2023
Craig 2	Retire 2023
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2025
Hayden 2	Retire 2024
Hunter 1	Retire 2028
Hunter 2	Retire 2029
Hunter 3	Retire 2030
Huntington 1	Retire 2028
Huntington 2	Retire 2029
Jim Bridger 1	Retire 2026
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2023
Jim Bridger 4	Retire 2024
Naughton 1	Retire 2023
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2030

GC = gas conversion

Portfolio: Social Cost of Carbon (P-18)

P-18 (Social Cost of Carbon)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-04, P-19 has all of the same retirement assumptions except was run with a low gas – medium CO_2 price policy scenario through the System Optimizer and Planning and Risk.

PORTFOLIO SUMMARY

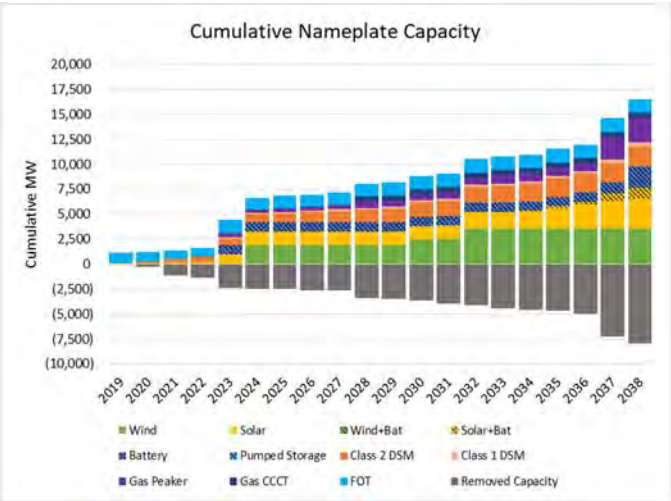
System Optimizer PVRR ($m) ***$20,882***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



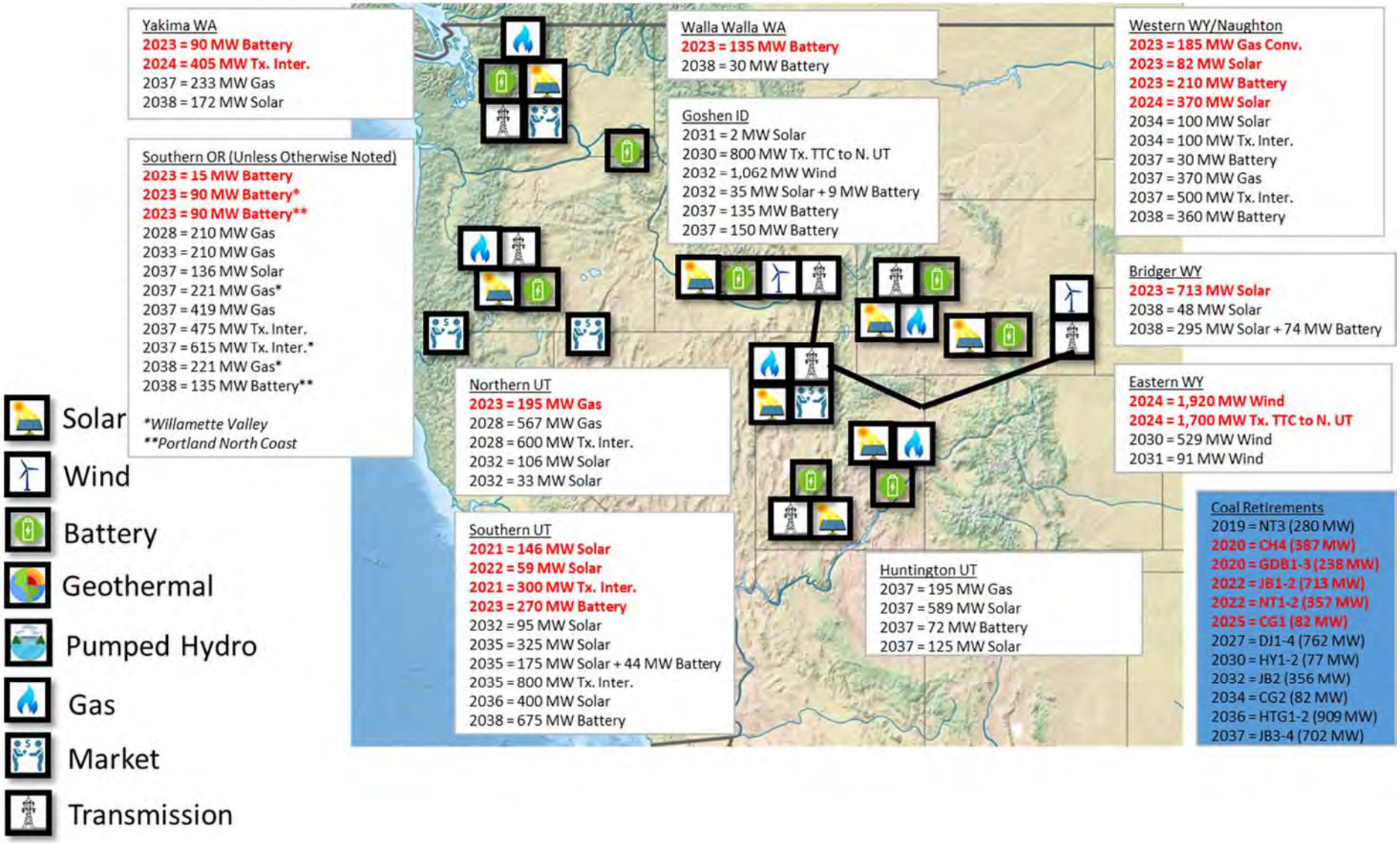
Retirement Assumptions

Initial portfolio-development case P-19 is P-04 with low gas. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2046
Colstrip 4	Retire 2046
Craig 1	Retire 2025
Craig 2	Retire 2034
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Retire 2019
Wyodak	Retire 2039

Portfolio: Low Gas (P-19)

P-19 (Low Gas)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-07, P-20 has all of the same retirement assumptions except was run with a high gas – medium CO_2 price policy scenario through the System Optimizer and Planning and Risk.

PORTFOLIO SUMMARY

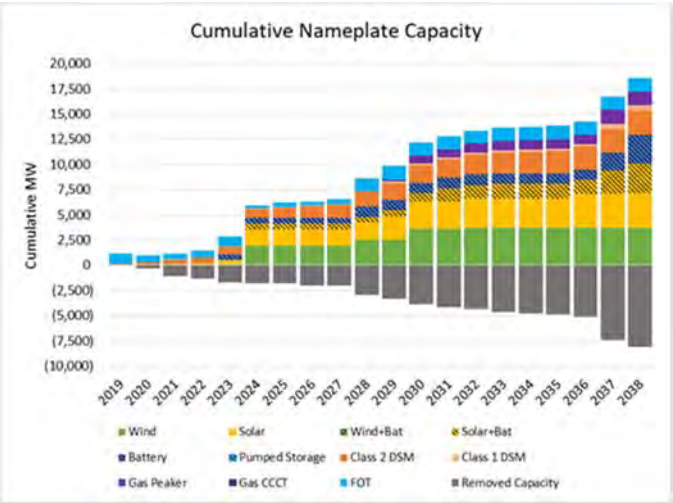
System Optimizer PVRR ($m) ***$22,746***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2030*	*200*
Yakima – to – S. Oregon/California	*2032*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

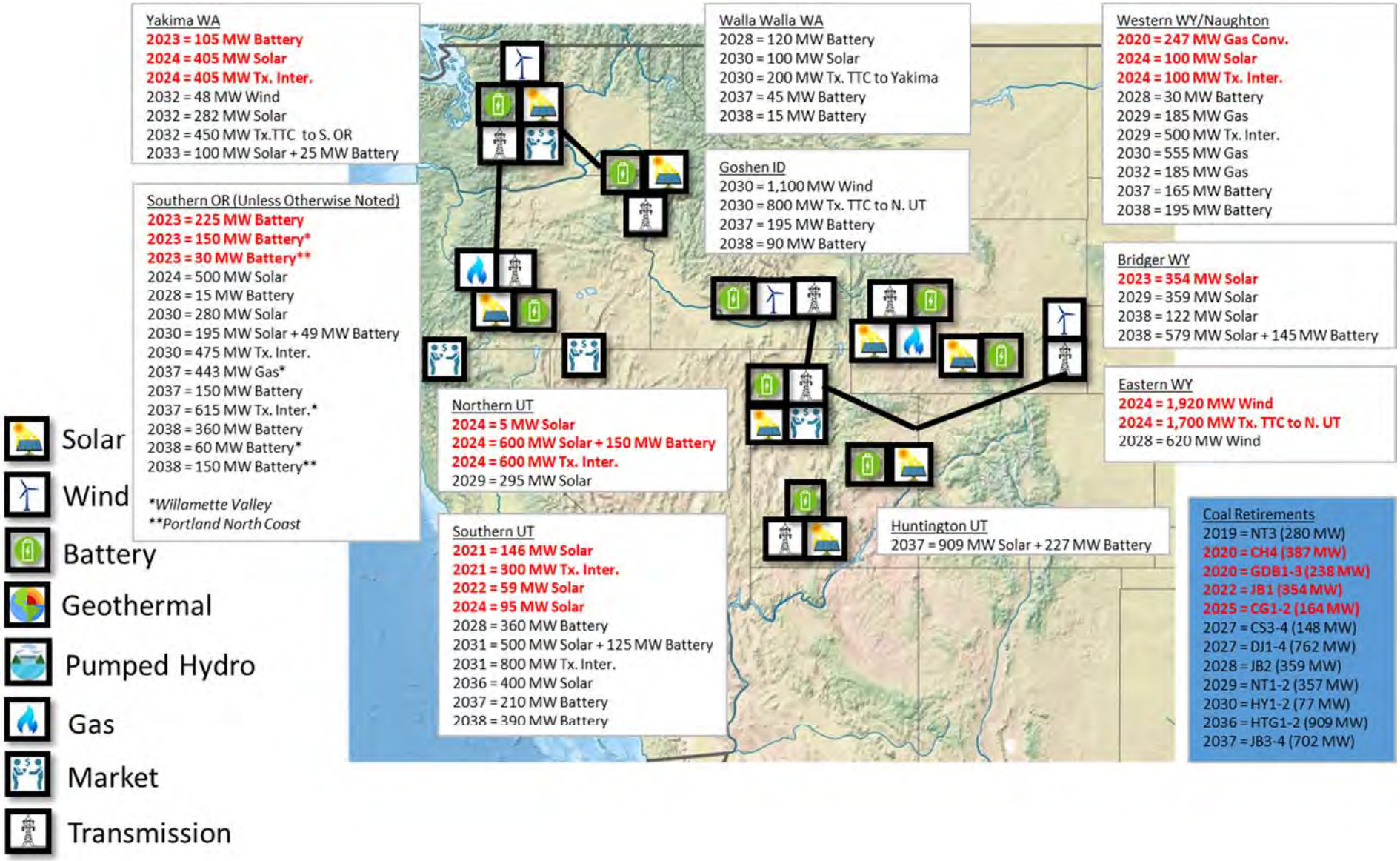
Initial portfolio-development case P-20 is P-07 with high gas. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2025
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: High Gas (P-20)

P-20 (High Gas)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, P-28 has the same retirement assumptions except accelerates retirement of Colstrip Unis 3 & 4 to 2025 instead of 2027.

PORTFOLIO SUMMARY

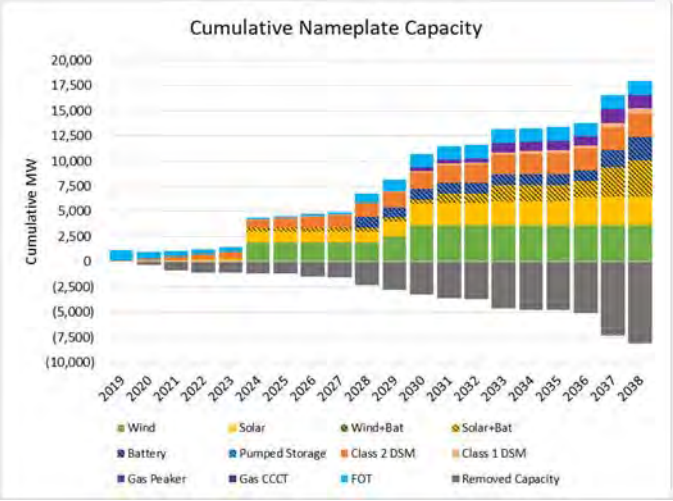
System Optimizer PVRR ($m) ***$21,805***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

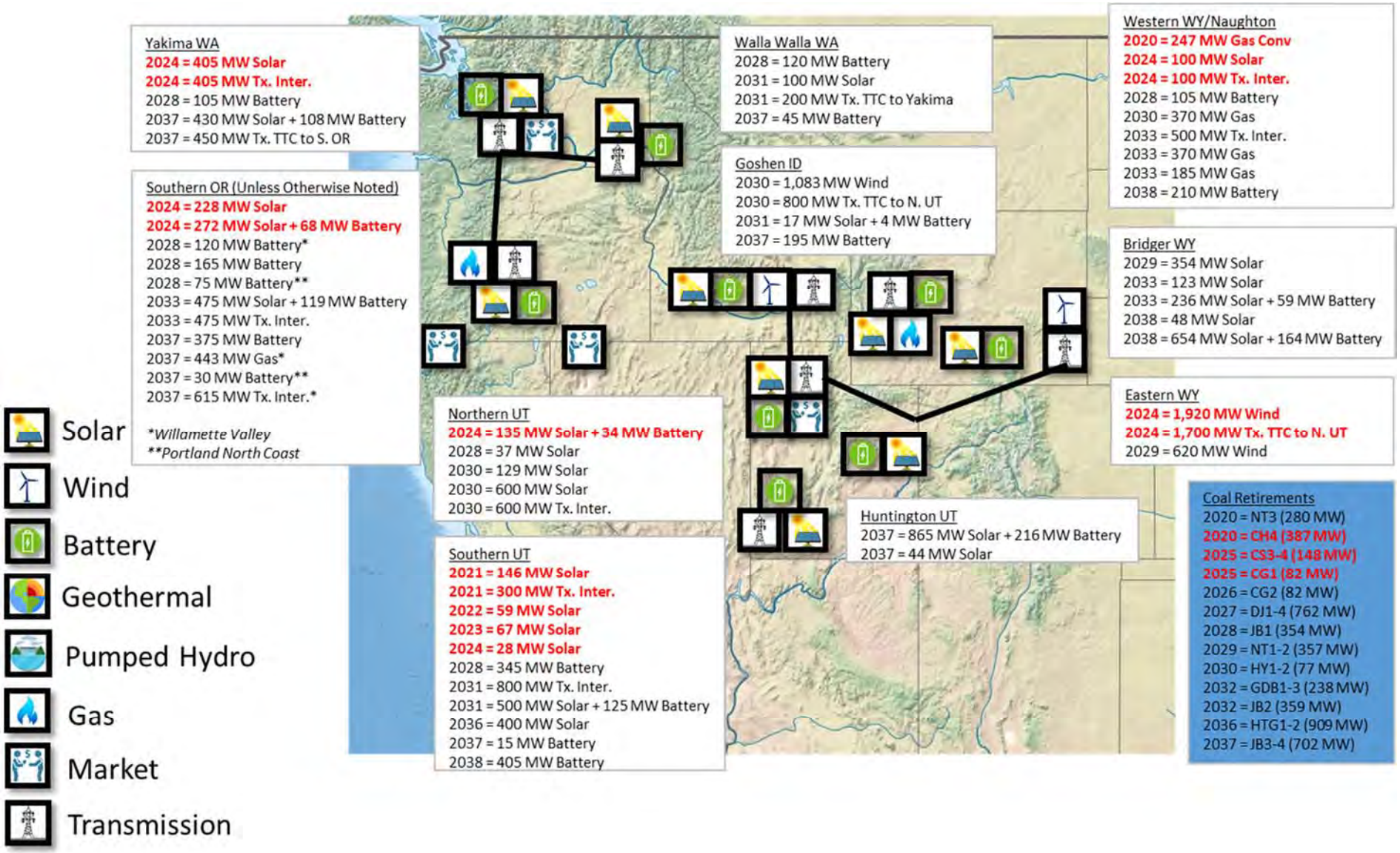
Initial portfolio-development case P-28 is P-11 with Colstrip Units 3 & 4 retirement accelerated to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Colstrip 3 & 4 Retirement 2025 (P-28)

P-28 (Colstrip 3-4 Retirement 2025)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, P-30 has all of the same retirement assumptions except accelerates retirement of Naughton Units 1 & 2 from 2029 to 2022.

PORTFOLIO SUMMARY

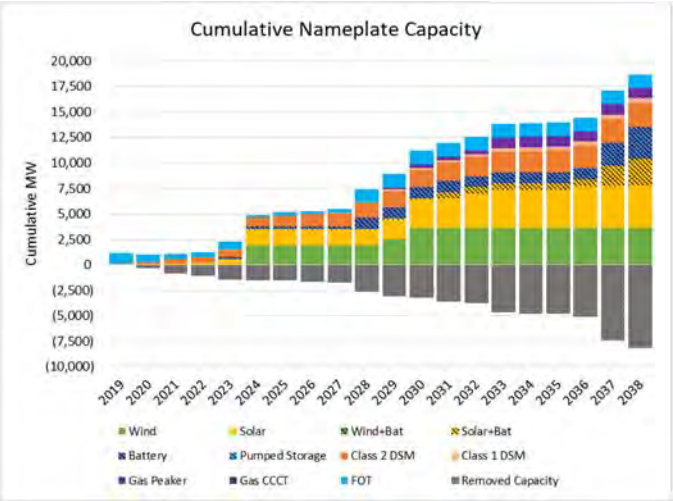
System Optimizer PVRR ($m) ***$21,708***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

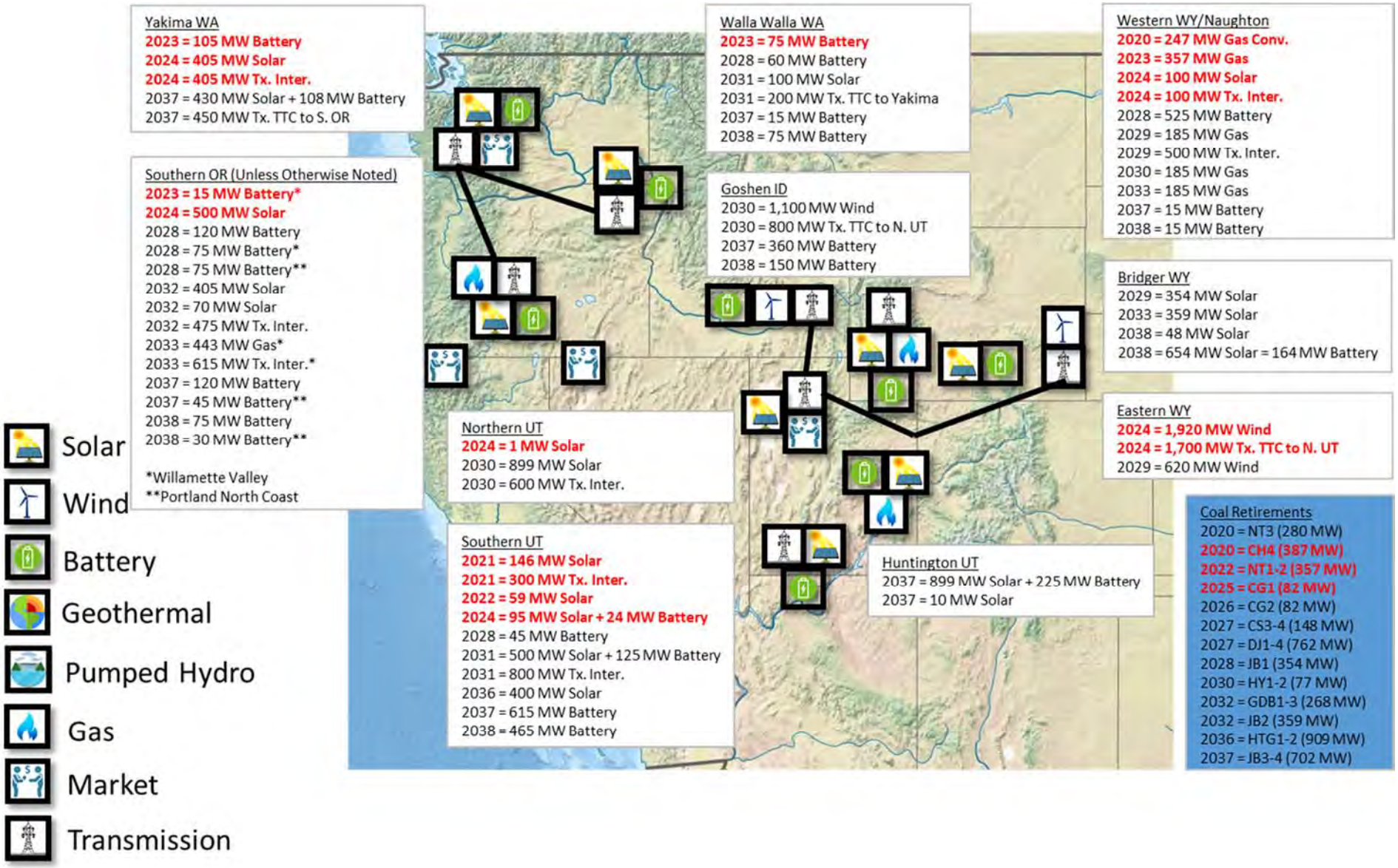
Initial portfolio-development case P-30 is P-11 with Naughton 1 & 2 Units retirement accelerated to 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2022
Naughton 2	Retire 2022
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 1 & 2 Retirement 2022 (P-30)

P-30 (Naughton 1 & 2 Retirement 2022)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, P-31 has all of the same retirement assumptions except accelerates retirement of Naughton Units 1 & 2 from 2029 to 2025.

PORTFOLIO SUMMARY

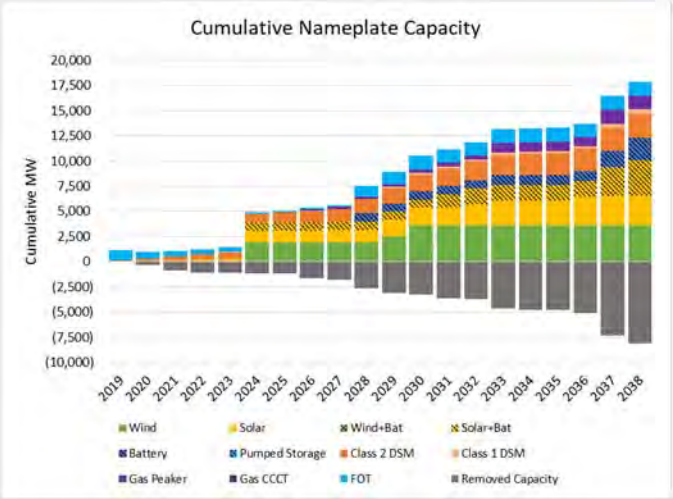
System Optimizer PVRR ($m) ***$23,484***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

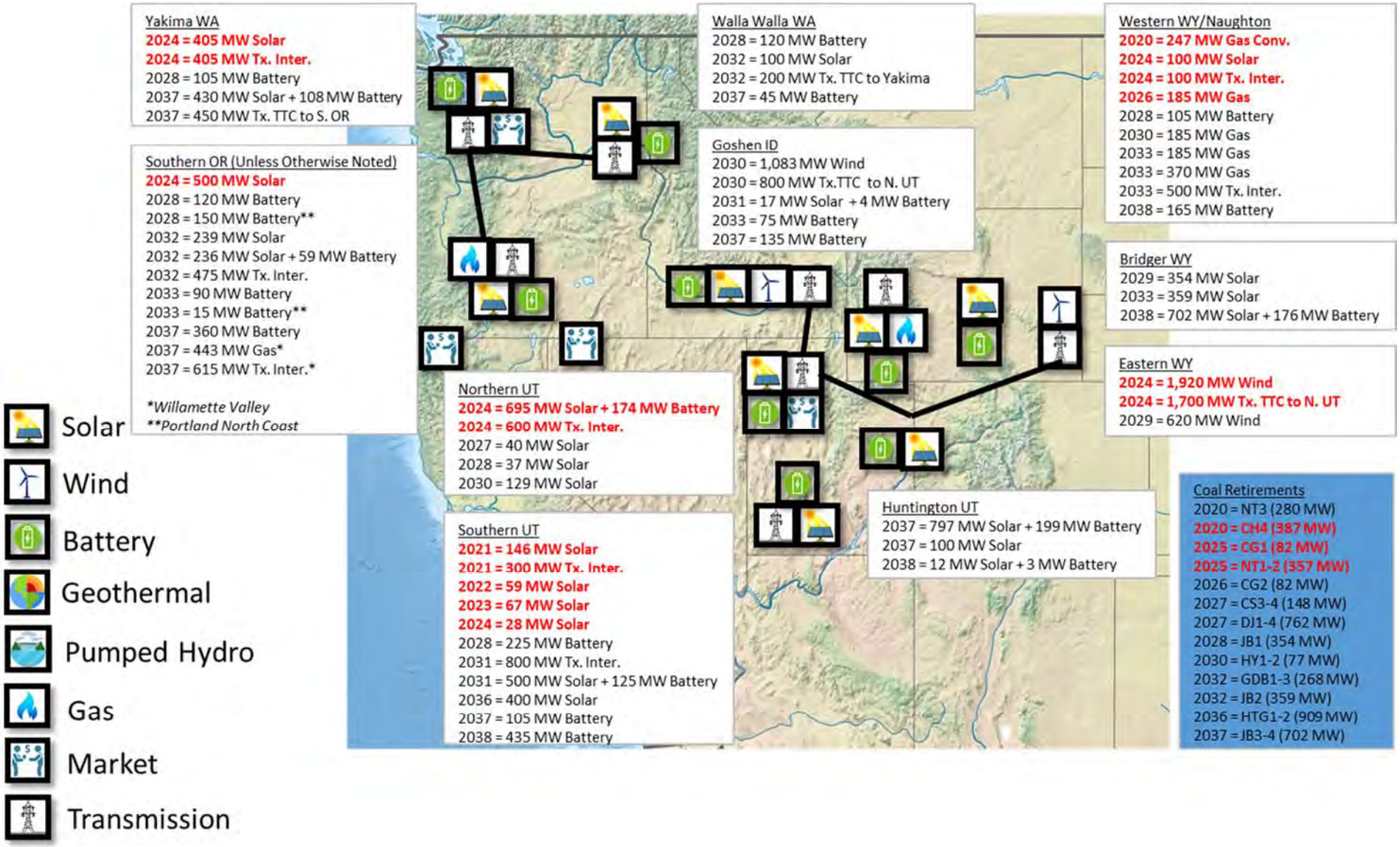
Initial portfolio-development case P-31 is P-11 with Naughton 1-2 Unit retirements accelerated to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 1 & 2 Retirement 2025 (P-31)

P-31 (Naughton 1 & 2 Retirement 2025)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-07, P-32 has all of the same retirement assumptions except accelerates retirement of Naughton Units 1 & 2 from 2029 to 2022, and slows retirements of Gadsby Units 1- 3 to 2032 from 2020.

PORTFOLIO SUMMARY

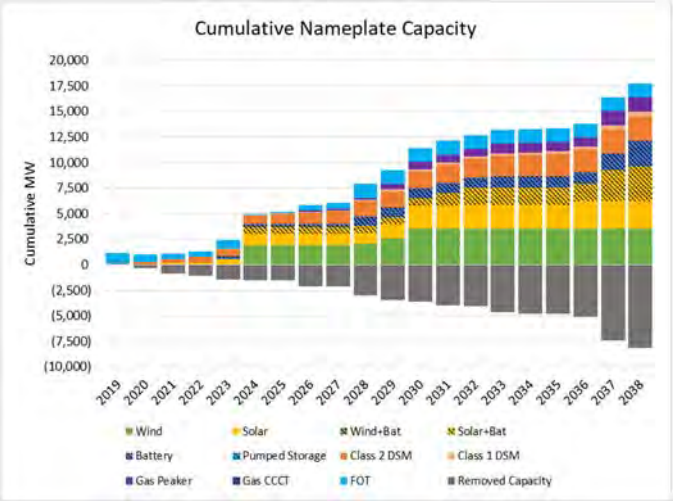
System Optimizer PVRR ($m) ***$21,763***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

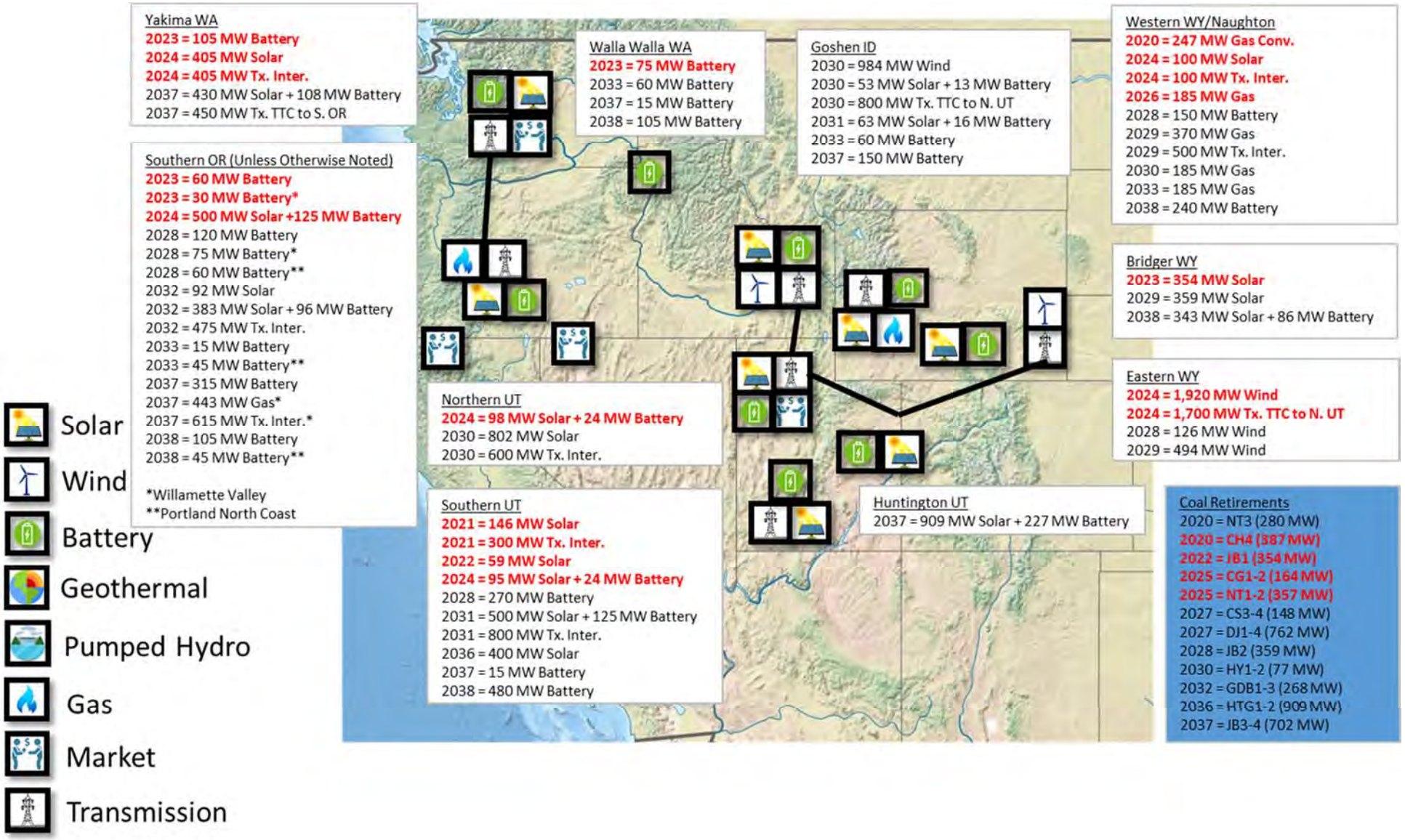
Initial portfolio-development case P-32 is P-07 with Naughton Units 1 & 2 retirement accelerated to 2025 and Gadsby 1-3 retiring in 2032. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2025
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 1 & 2 Retirement 2025 with Gadsby 1-3 Retirement 2032 (P-32)

P-32 (Naughton 1 & 2 Retirement 2025 with Gadsby 1-3 Retirement 2032)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, P-33 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit 1 from 2028 to 2022 and Unit 2 from 2032 to 2022.

PORTFOLIO SUMMARY

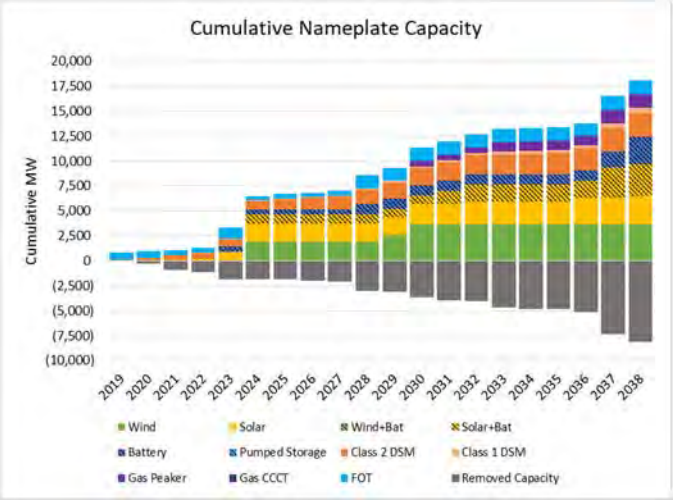
System Optimizer PVRR ($m) ***$21,895***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

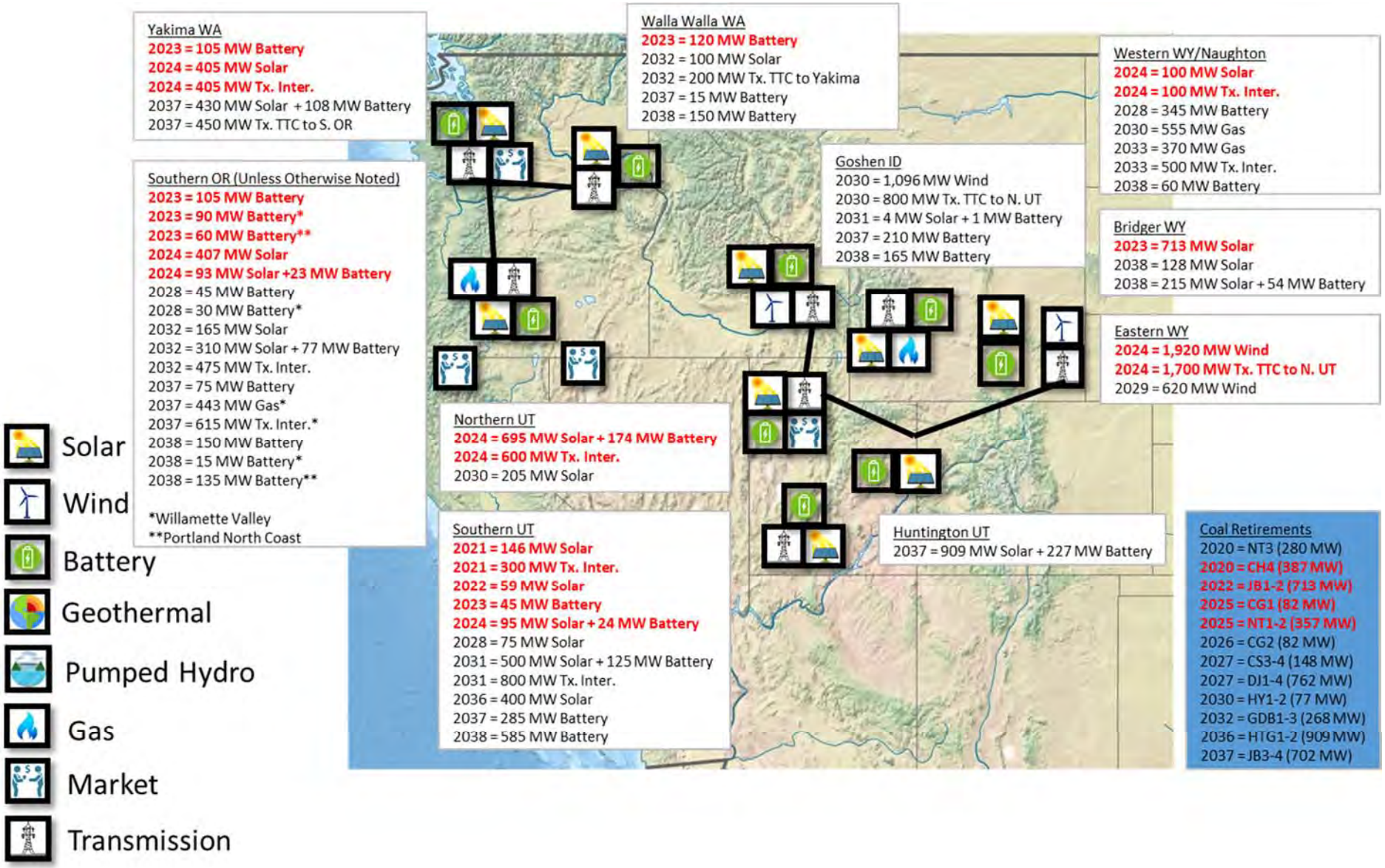
Initial portfolio-development case P-33 is P-11 with Jim Bridger Units 1-2 retirement accelerated to 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 Retirement 2022 (P-33)

P-33 (Jim Bridger 1 & 2 Retirement 2022)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, and a sibling of P-33, P-34 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit from 2028 to 2022 and Unit 2 from 2032 to 2022. In addition, P-34 accelerates retirement of Gadsby Units 1- 3 from 2032 to 2022.

PORTFOLIO SUMMARY

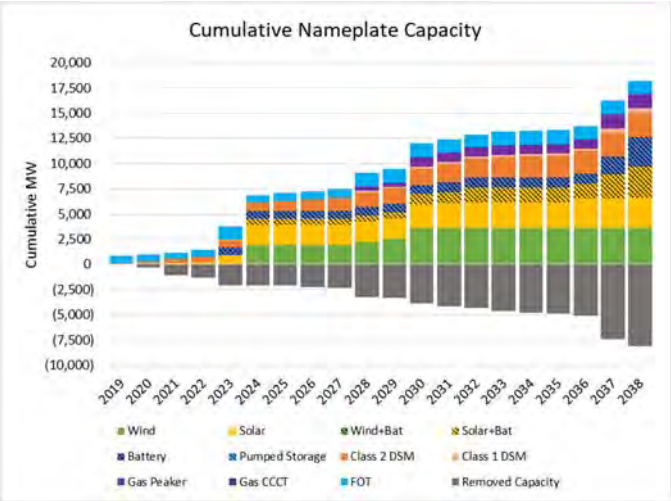
System Optimizer PVRR ($m) ***$21,949***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

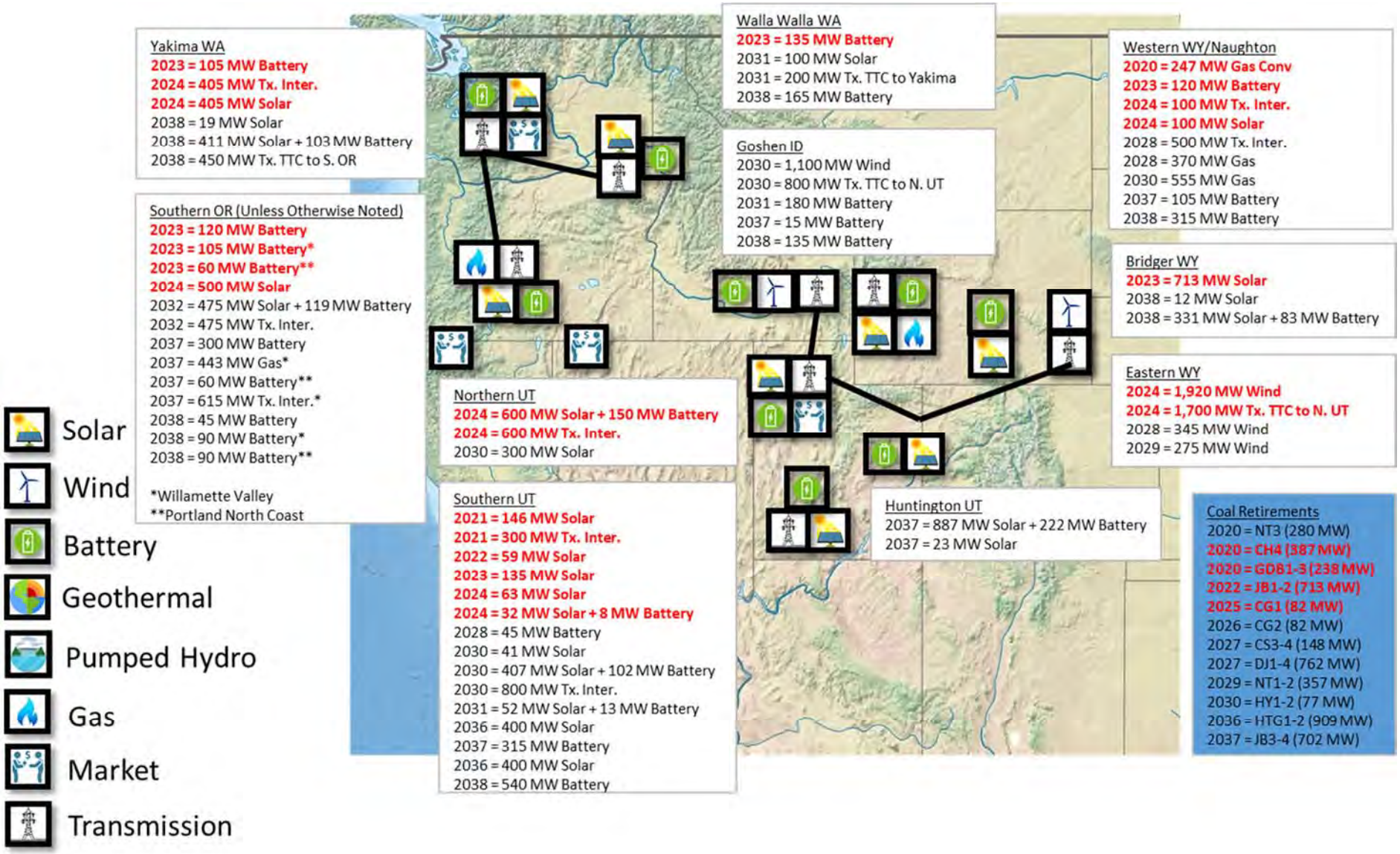
Initial portfolio-development case P-34 is P-11 with Gadsby Units 1-3 retirement accelerated to 2020 and Jim Bridger Units 1 & 2 retirements accelerated to 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2020
Gadsby 2	Retire 2020
Gadsby 3	Retire 2020
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2022
Jim Bridger 2	Retire 2022
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 Retirement 2022 with Gadsby 1-3 Retirement 2020 (P-34)

P-34 (Jim Bridger 1 & 2 Retirement 2022 with Gadsby 1-3 Retirement 2020)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-11, and a sibling of P-33 & P-34, P-35 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2037 to 2022.

PORTFOLIO SUMMARY

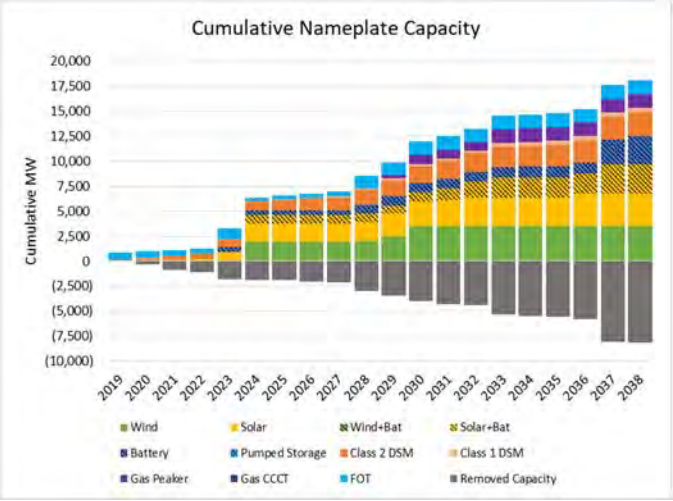
System Optimizer PVRR ($m) ***$21,732***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2031*	*200*
Yakima – to – S. Oregon/California	*2033*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

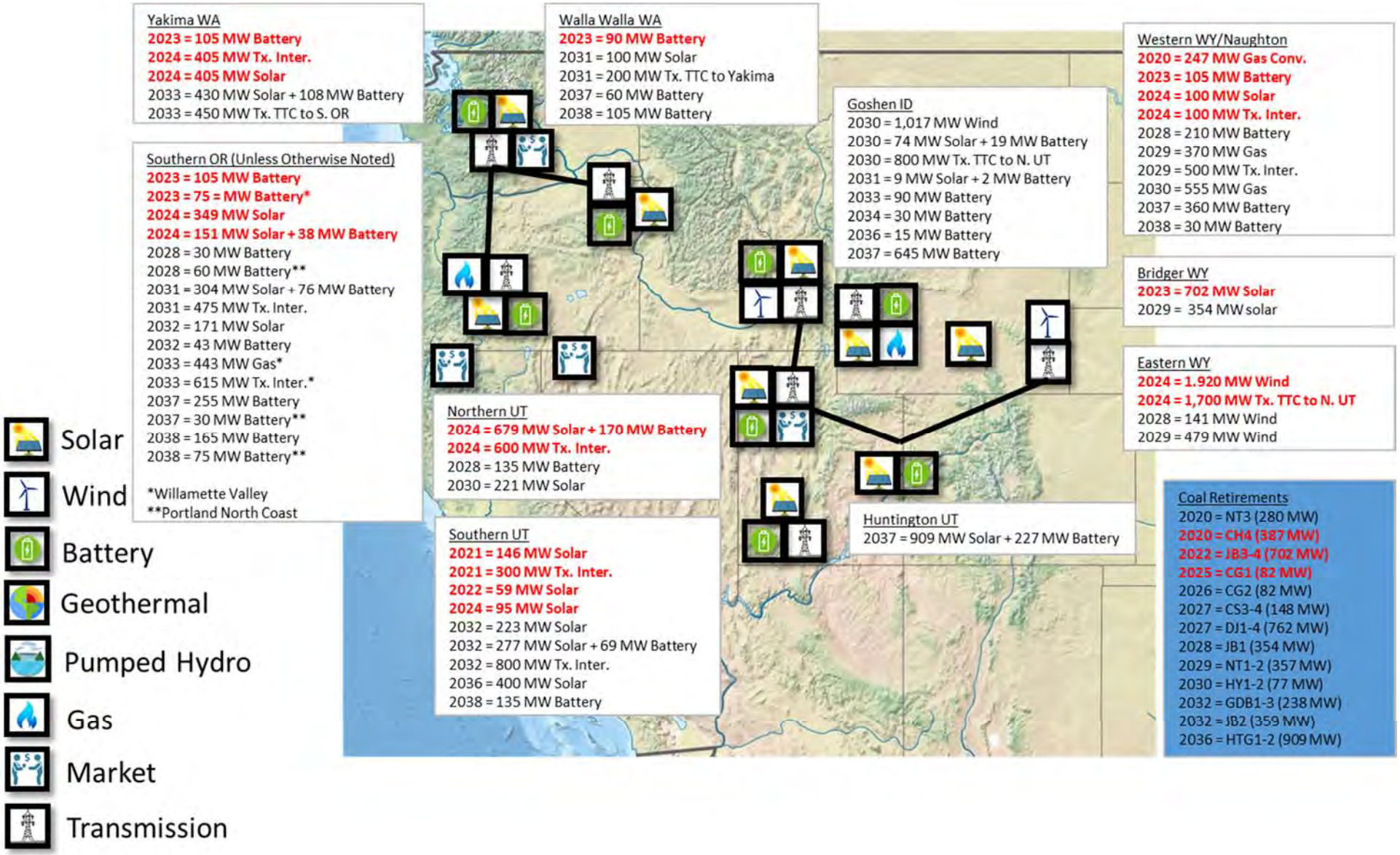
Initial portfolio-development case P-35 is P-11 with Jim Bridger Units 3 & 4 retirement accelerated to 2022. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2022
Jim Bridger 4	Retire 2022
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3-4 Retirement 2022 (P-35)

P-35 (Jim Bridger 3 & 4 Retirement 2022)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, P-45 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit 1 from 2028 to 2023 and Jim Bridger Unit 2 from 2032 to 2028.

PORTFOLIO SUMMARY

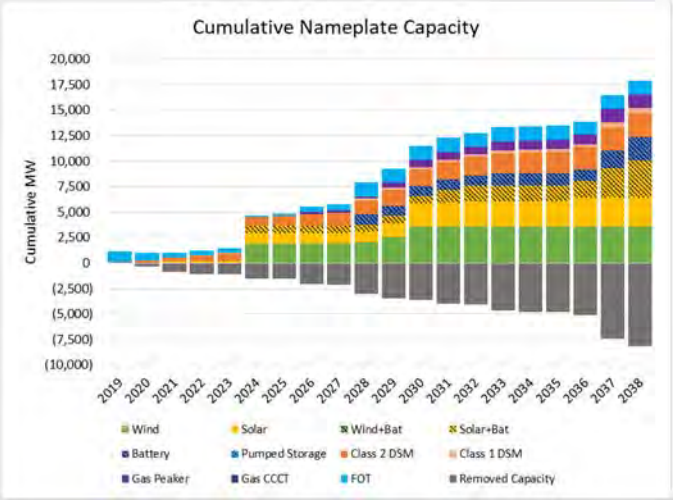
System Optimizer PVRR ($m) ***$21,593***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

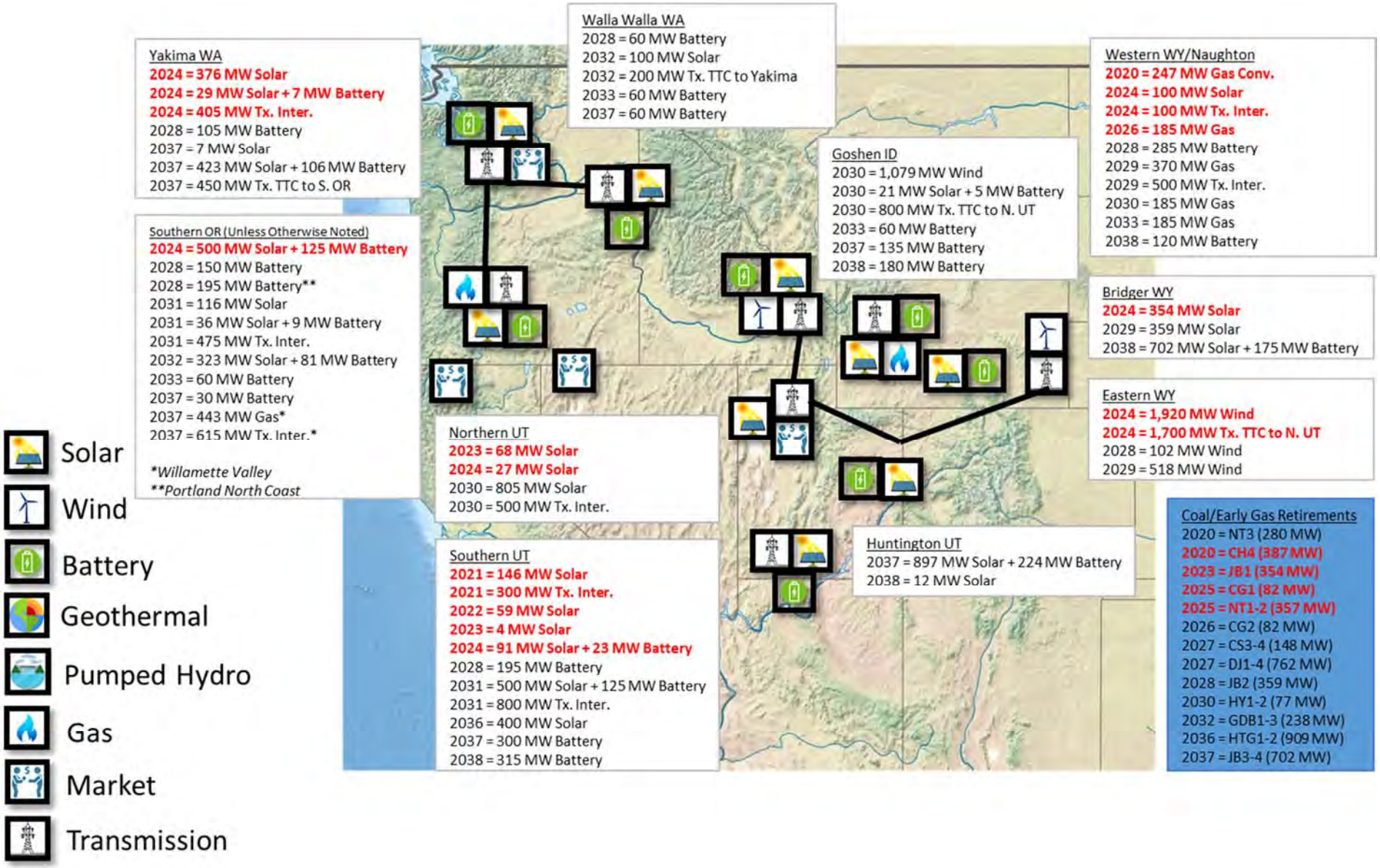
Initial portfolio-development case P-45 is P-31 with Jim Bridger Unit 1 retiring in 2023, Jim Bridger Unit 2 retiring in 2028. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 Retirement 2023, Jim Bridger 2 Retirement 2028 (P-45)

P-45 (Jim Bridger 1 Retirement 2023, Jim Bridger 2 Retirement 2028)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, and a sibling of P-45, P-46 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2037 to 2025.

PORTFOLIO SUMMARY

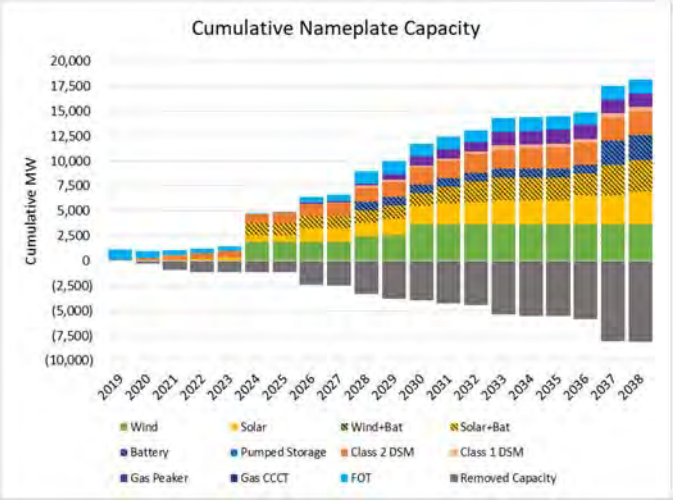
System Optimizer PVRR ($m) ***$21,419***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

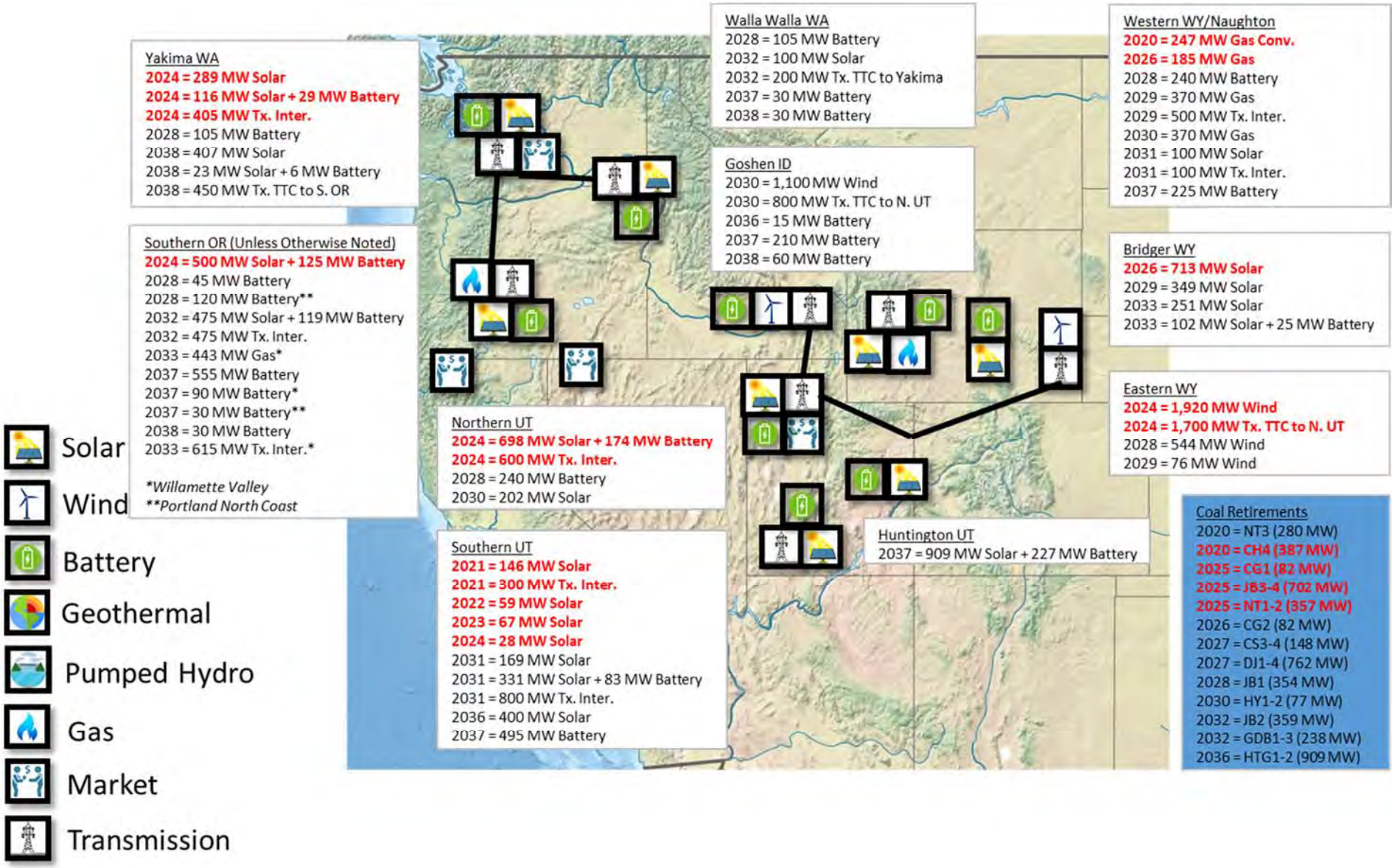
Initial portfolio-development case P-46 is P-31 with Jim Bridger Units 3 & 4 retiring in 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2025
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2025 (P-46)

P-46 (Jim Bridger 3 & 4 Retirement 2025)



Portfolio: Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, and a sibling of P-46, P-53 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit 1 from 2028 to 2025, Jim Bridger Unit 2 from 2032 to 2025, Jim Bridger Unit 3 from 2037 to 2028, and Jim Bridger Unit 4 from 2037 to 2032.

PORTFOLIO SUMMARY

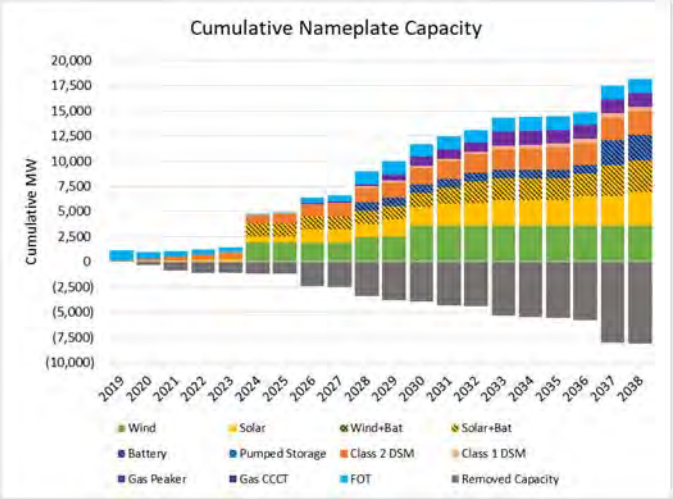
System Optimizer PVRR ($m) ***$21,438***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2032*	*200*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

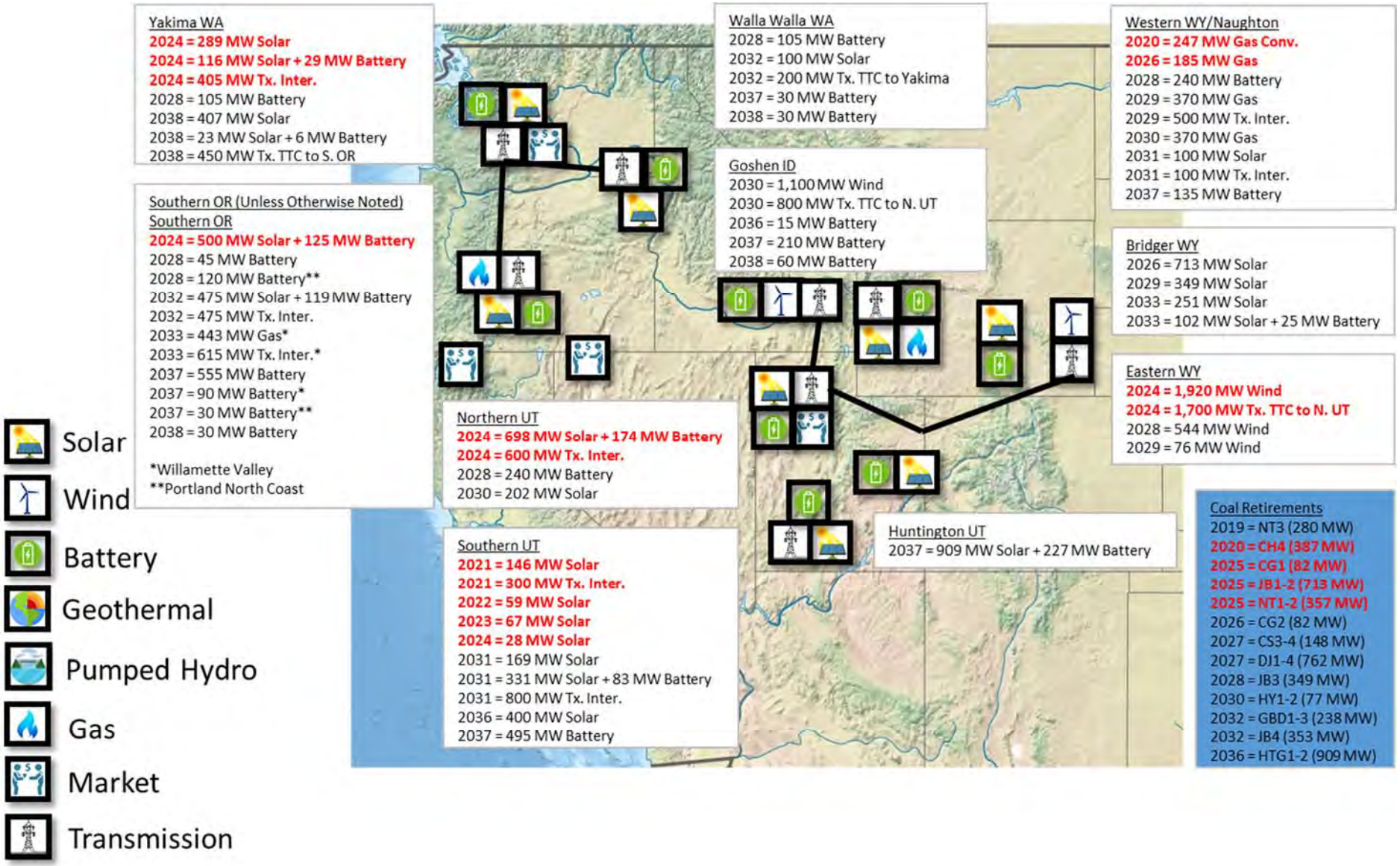
Initial portfolio-development case P-53 is P-31 with Jim Bridger Units 1 & 2 retiring in 2025, Jim Bridger Unit 3 retiring in 2028, and Jim Bridger Unit 4 retiring in 2032. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2025
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2028
Jim Bridger 4	Retire 2032
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = Gas Conversion

Portfolio: Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53)

P-53 (Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032)



Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, P-54 has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit 2 from 2032 to 2024.

PORTFOLIO SUMMARY

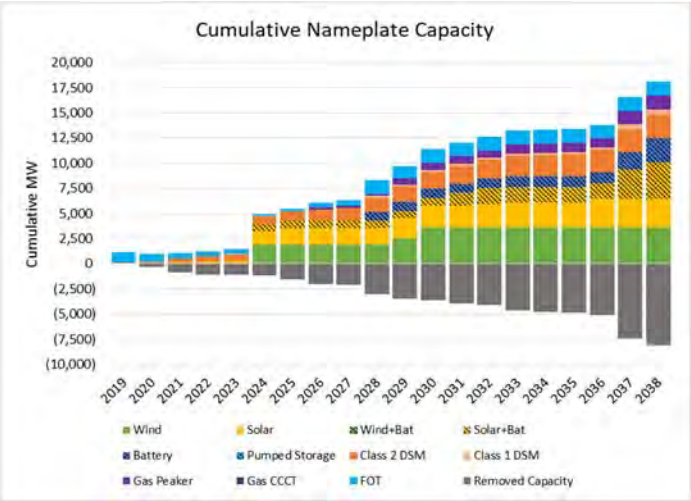
System Optimizer PVRR ($m) ***$23,708***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2025*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Walla Walla – to Yakima, Expansion	*2033*	*200*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

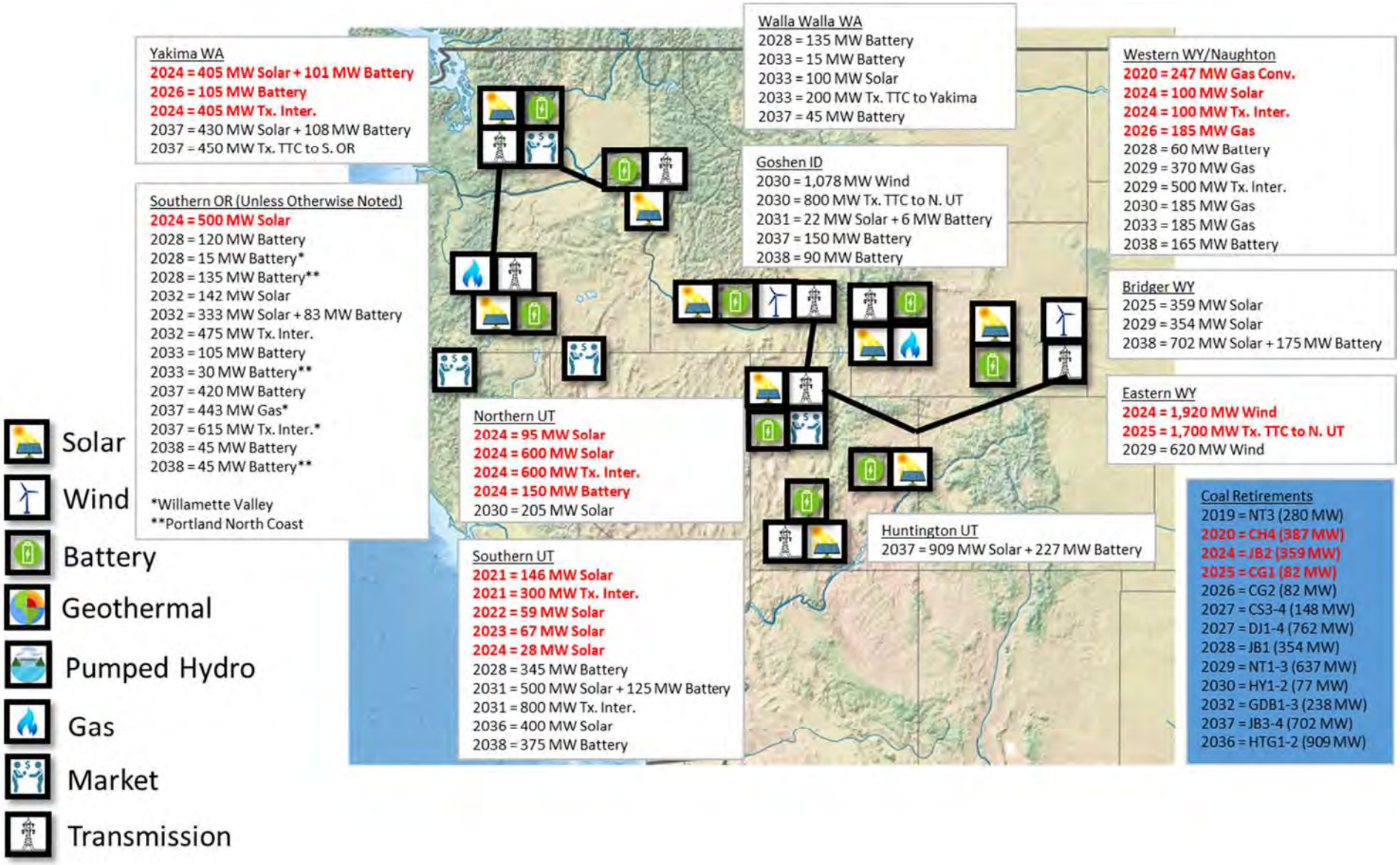
Initial portfolio-development case P-54 is P-31 with Jim Bridger 2 retiring in 2024. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2024
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = Gas Conversion

Portfolio: Jim Bridger 2 Retirement 2024 (P-54)

P-54 (Jim Bridger 2 Retirement 2024)



C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of P-11, P-31C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038 to include 2024 through 2029.

PORTFOLIO SUMMARY

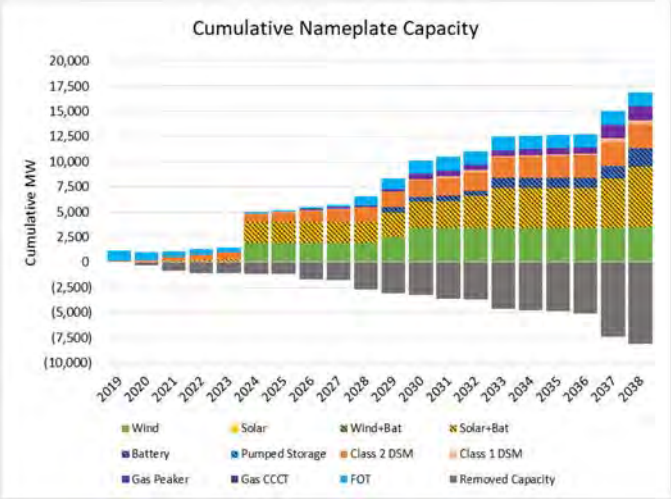
System Optimizer PVRR ($m) ***$21,639***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2038*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

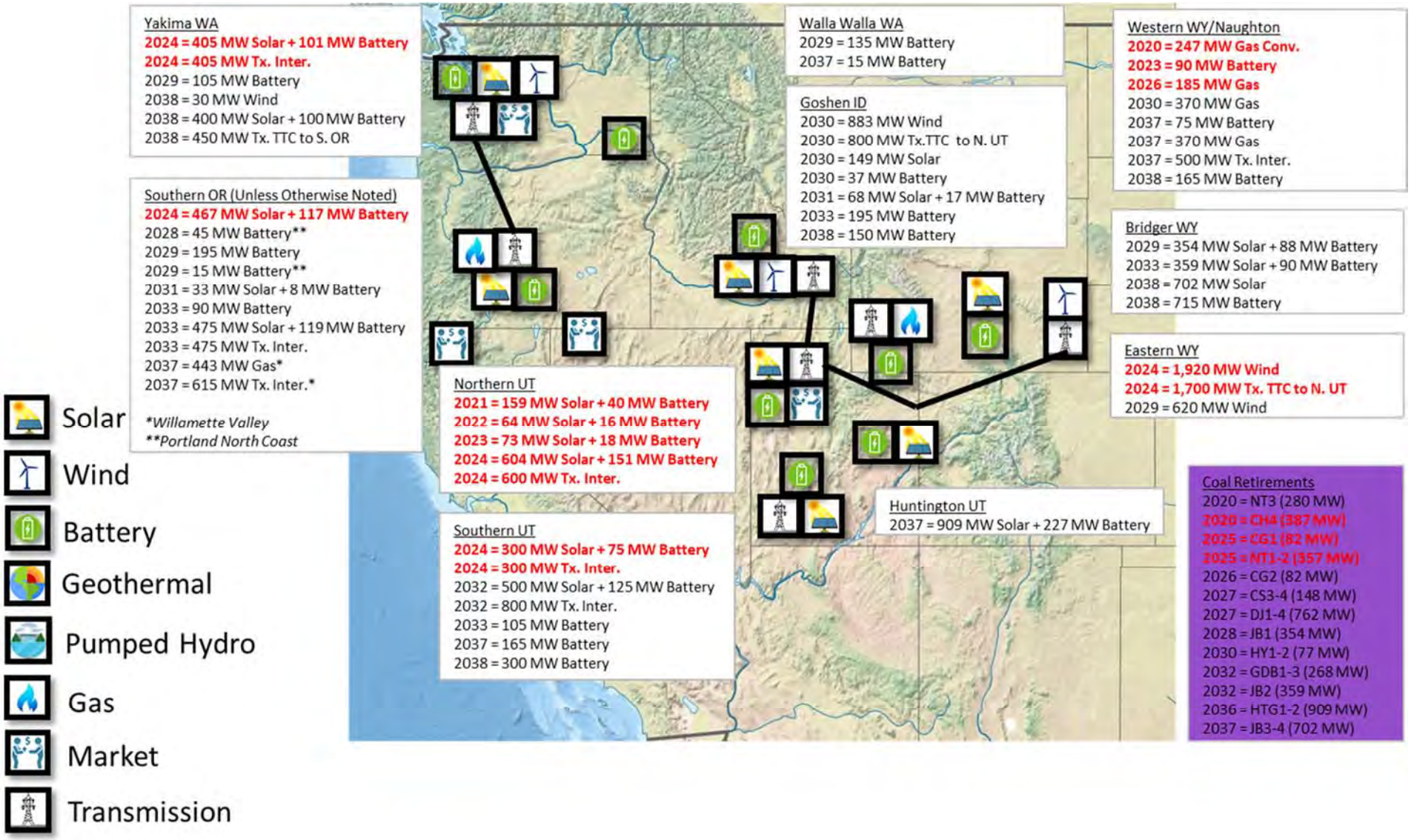
A variant of case P-11, P-31C has all of the same retirement assumptions except accelerates retirement of Naughton Units 1 & 2 from 2029 to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Naughton 1 & 2 Retirement 2025 (P-31C)

P-31C (Naughton 1 & 2 Retirement 2025)



C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-46, P-36C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

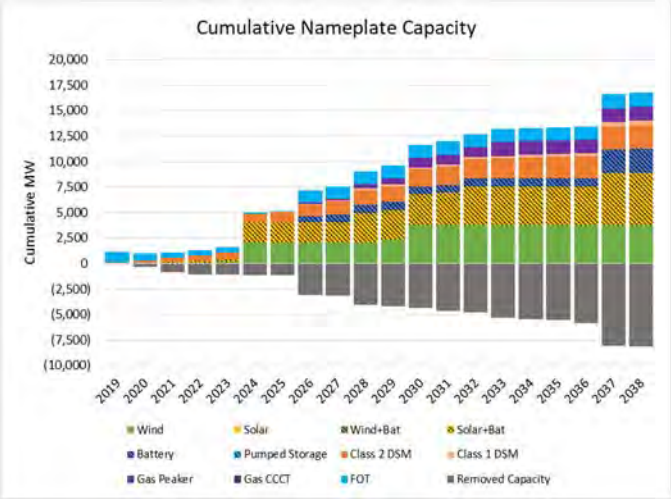
System Optimizer PVRR ($m) ***$21,544***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

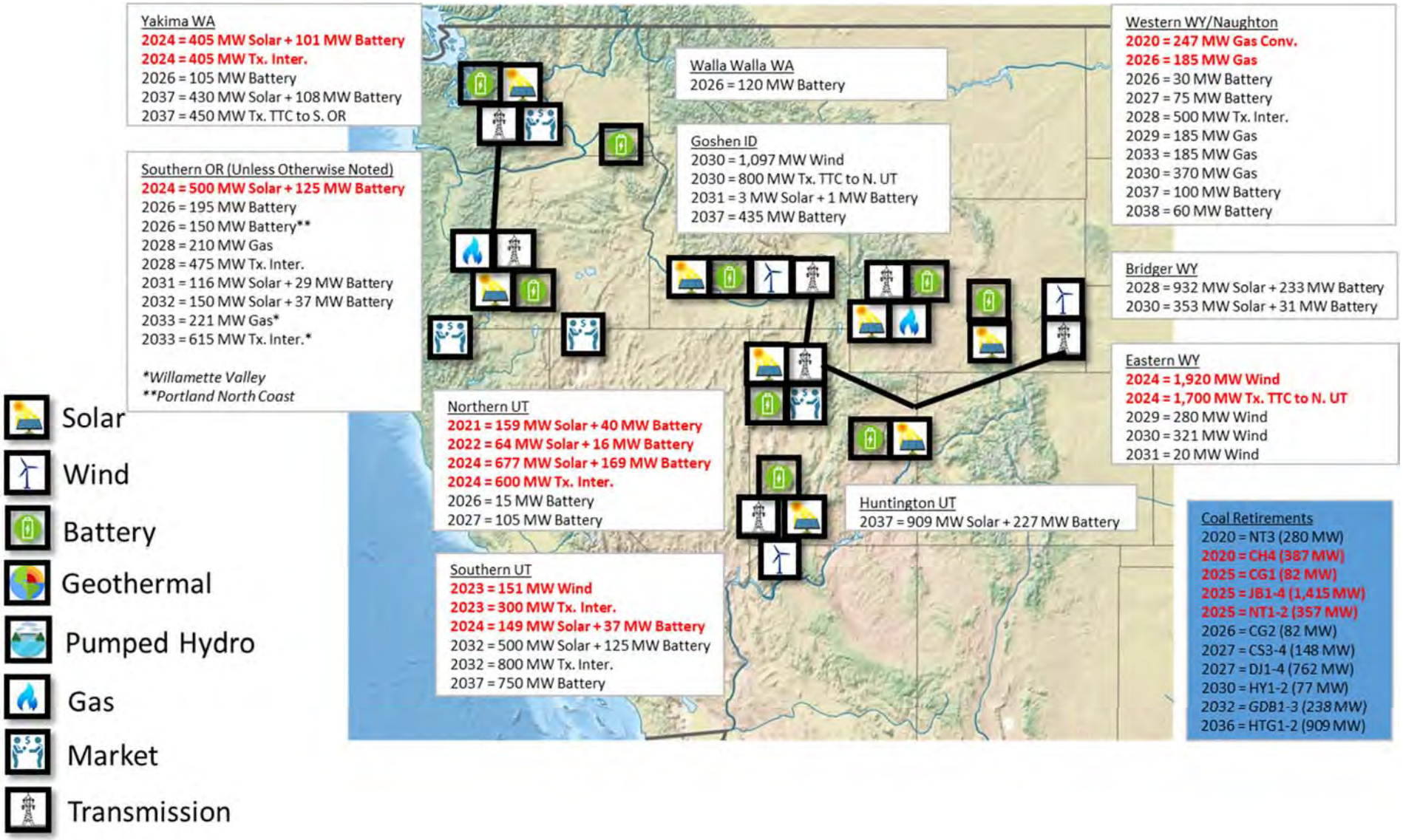
A variant of case P-14, P-36C has all of the same retirement assumptions except slows retirement of Jim Bridger Units 1-4 and Naughton Units 1 & 2 from 2022 to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2025
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2025
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 & Naughton 1&2 Retiring 2025 (P-36C)

P-36C (Jim Bridger 1 & 2 and Naughton 1 & 2 Retiring 2025)



C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, P-45C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

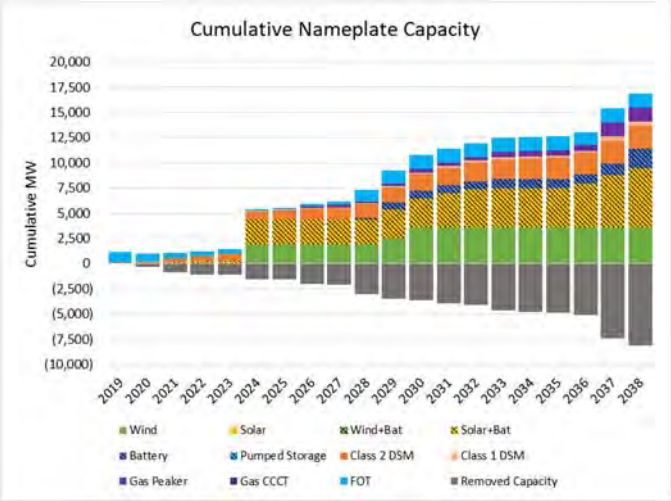
System Optimizer PVRR ($m) ***$21,537***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

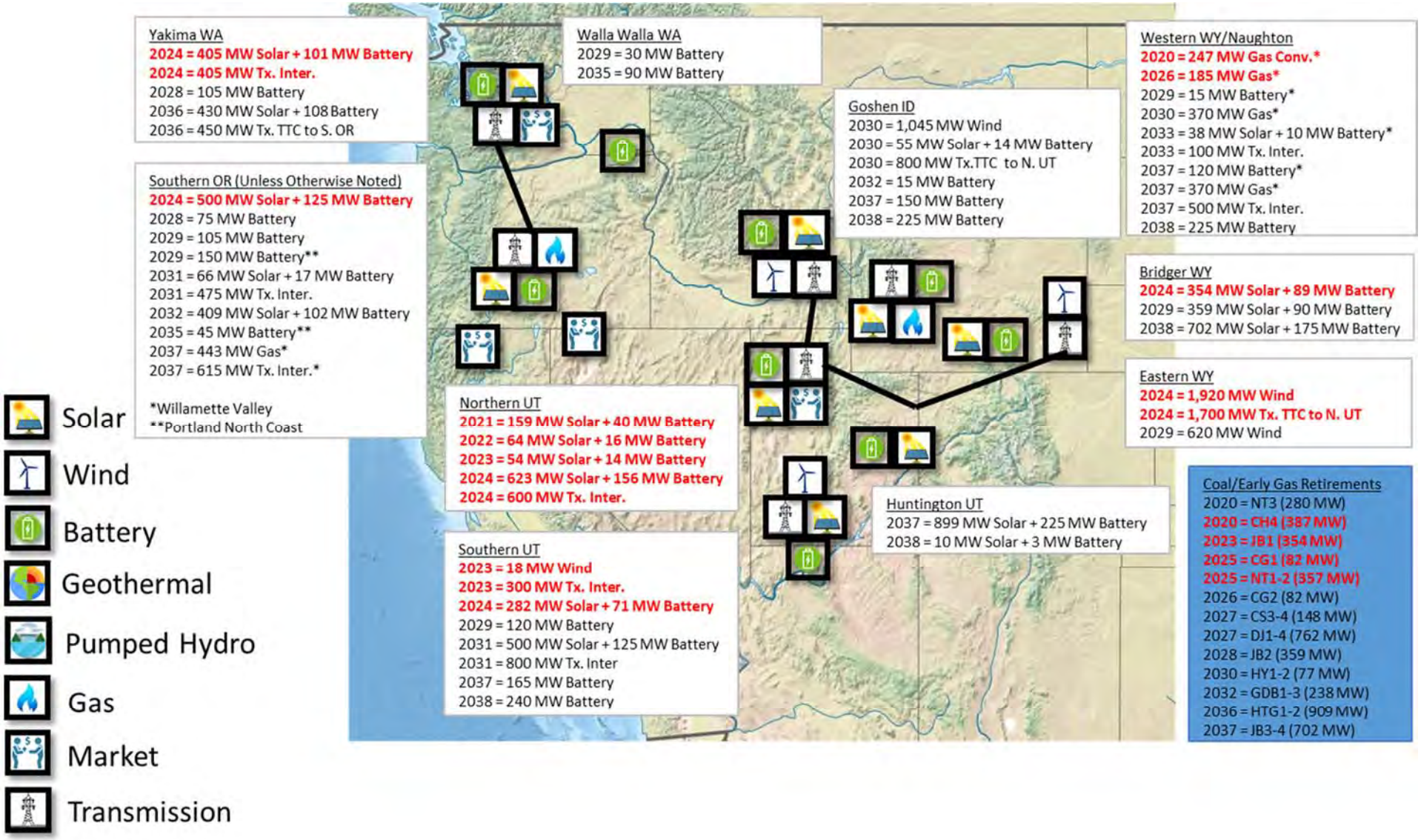
A variant of case P-31, P-45C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Unit 1 from 2028 to 2023 and Unit 2 from 2032 to 2028. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2038 (P-45C)

P-45C (Jim Bridger 1 Retirement 2023 & Jim Bridger 2 Retirement 2038)



C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-31, P-46C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

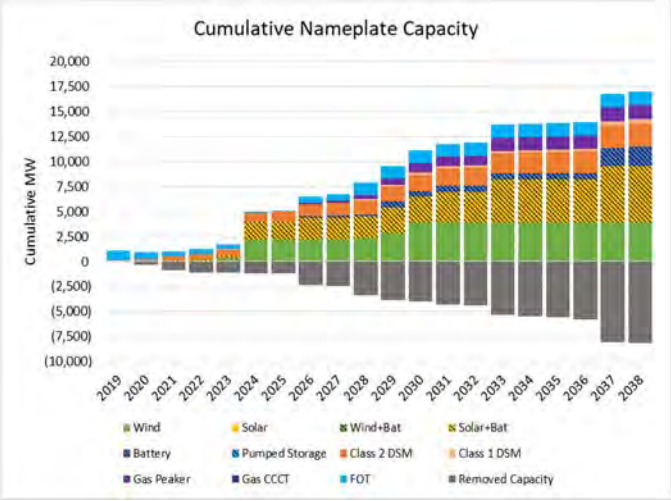
System Optimizer PVRR ($m) ***$21,431***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

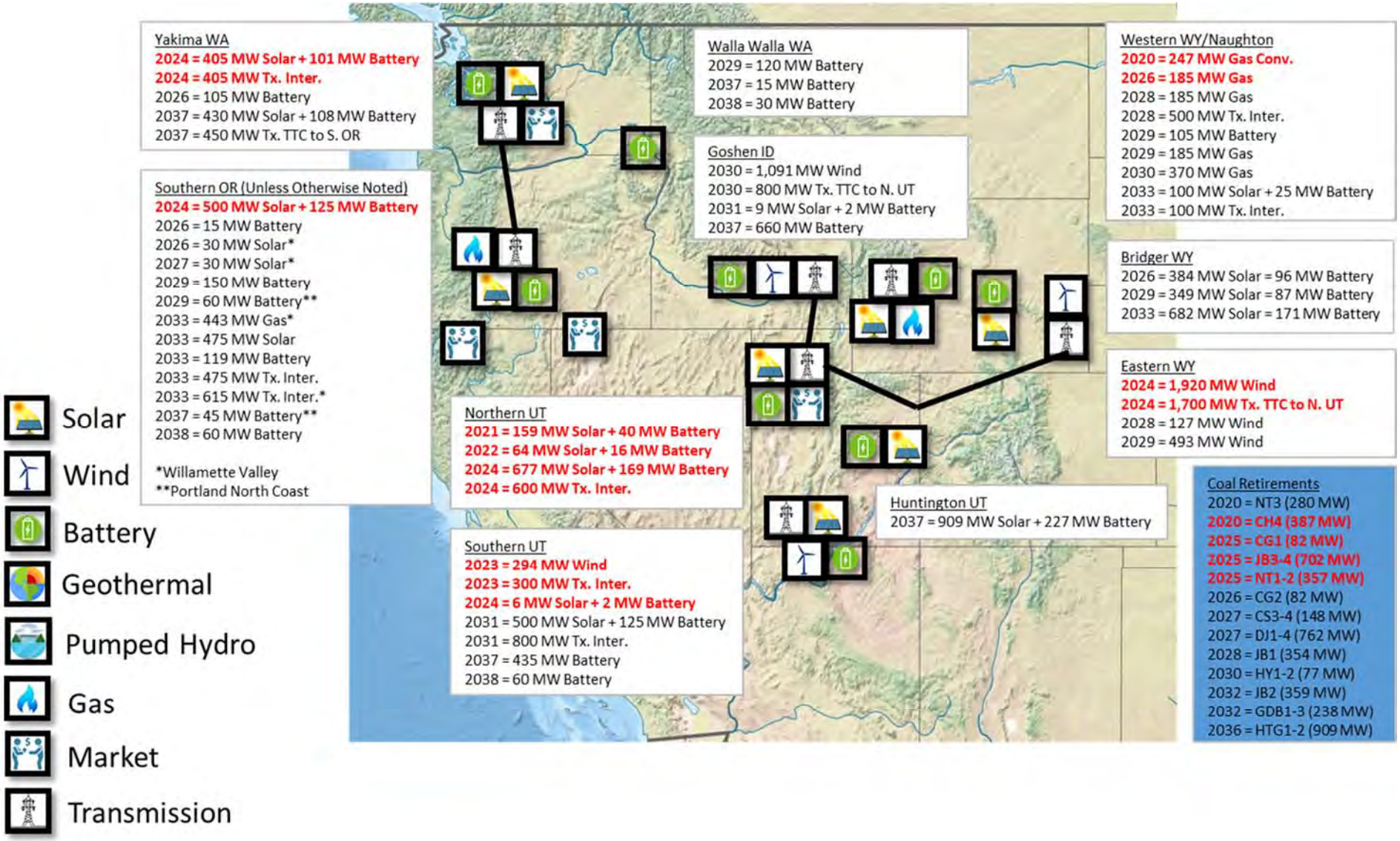
A variant of case P-31C, and a sibling of P-45C, P-46C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2037 to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2025
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2025 (P-46C)

P-46C (Jim Bridger 3 & 4 Retirement 2025)



C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of sibling case P-46C, P-46J23C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2025 to 2023. In addition, it was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

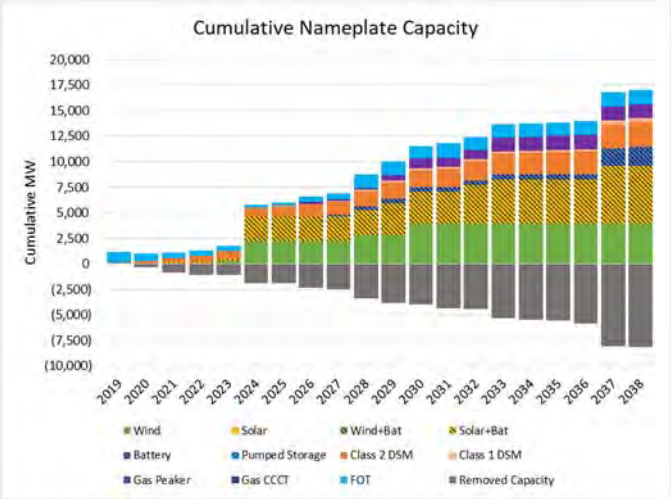
System Optimizer PVRR ($m) ***$21,385***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

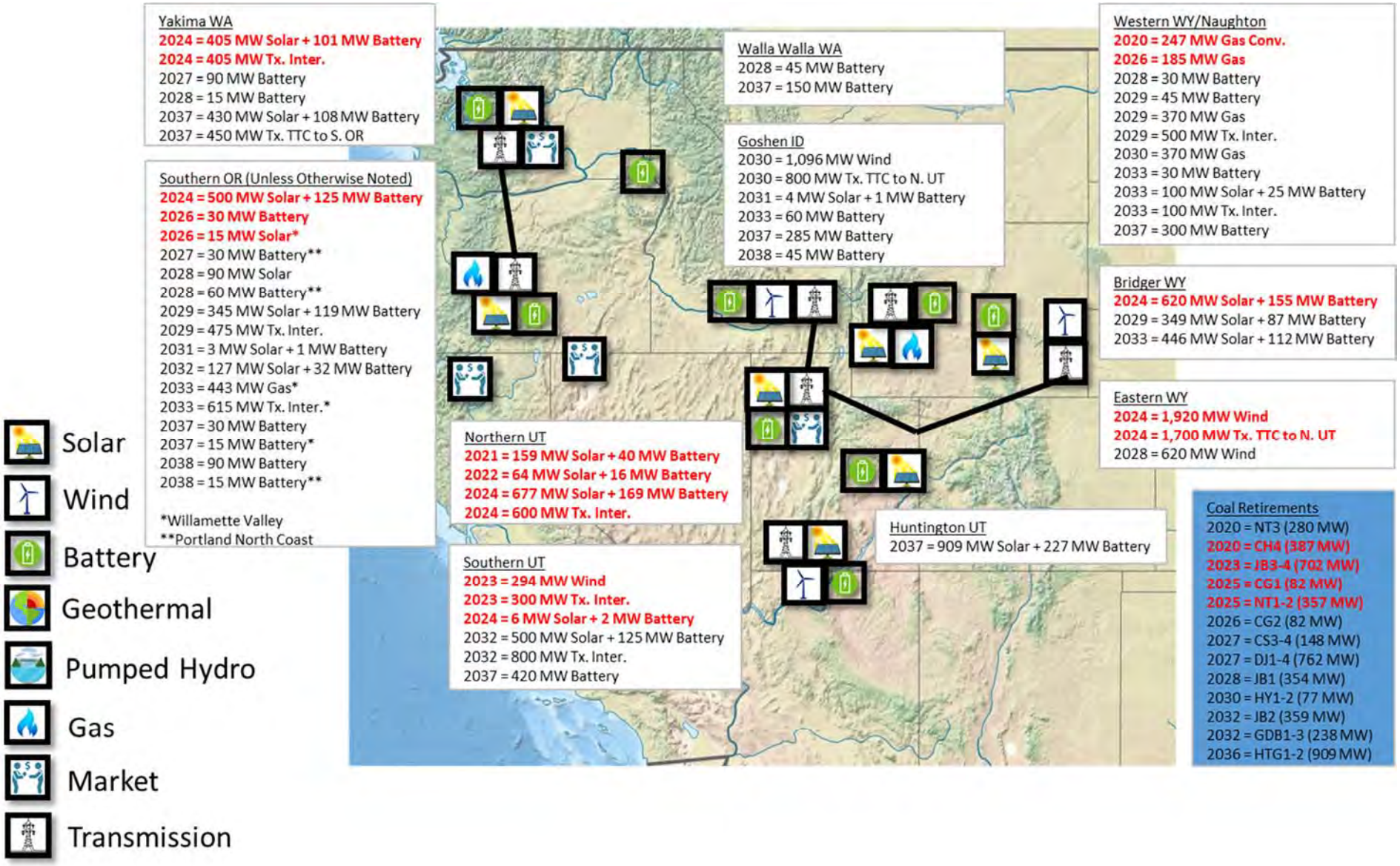
C-Case portfolio-development case P-46J23C is P-46C with Jim Bridger Units 3-4 retiring in 2023. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2023
Jim Bridger 4	Retire 2023
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2023 (P-46J23C)

P-46J23C (Jim Bridger 3 & 4 Retirement 2023)



C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-45C, P-47C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2037 to 2035. In addition, it was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

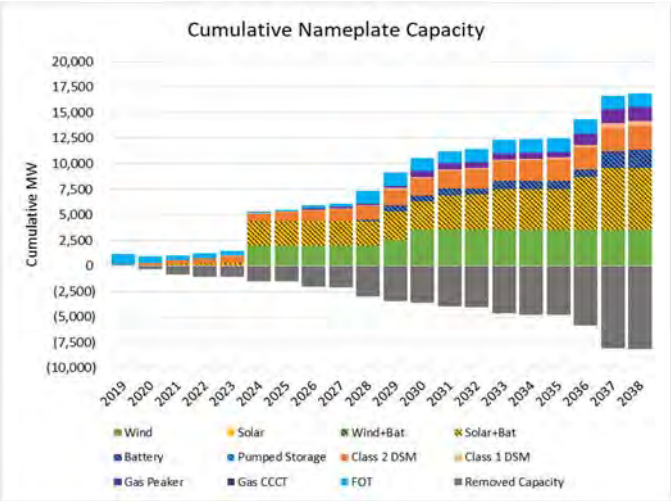
System Optimizer PVRR ($m) ***$21,467***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

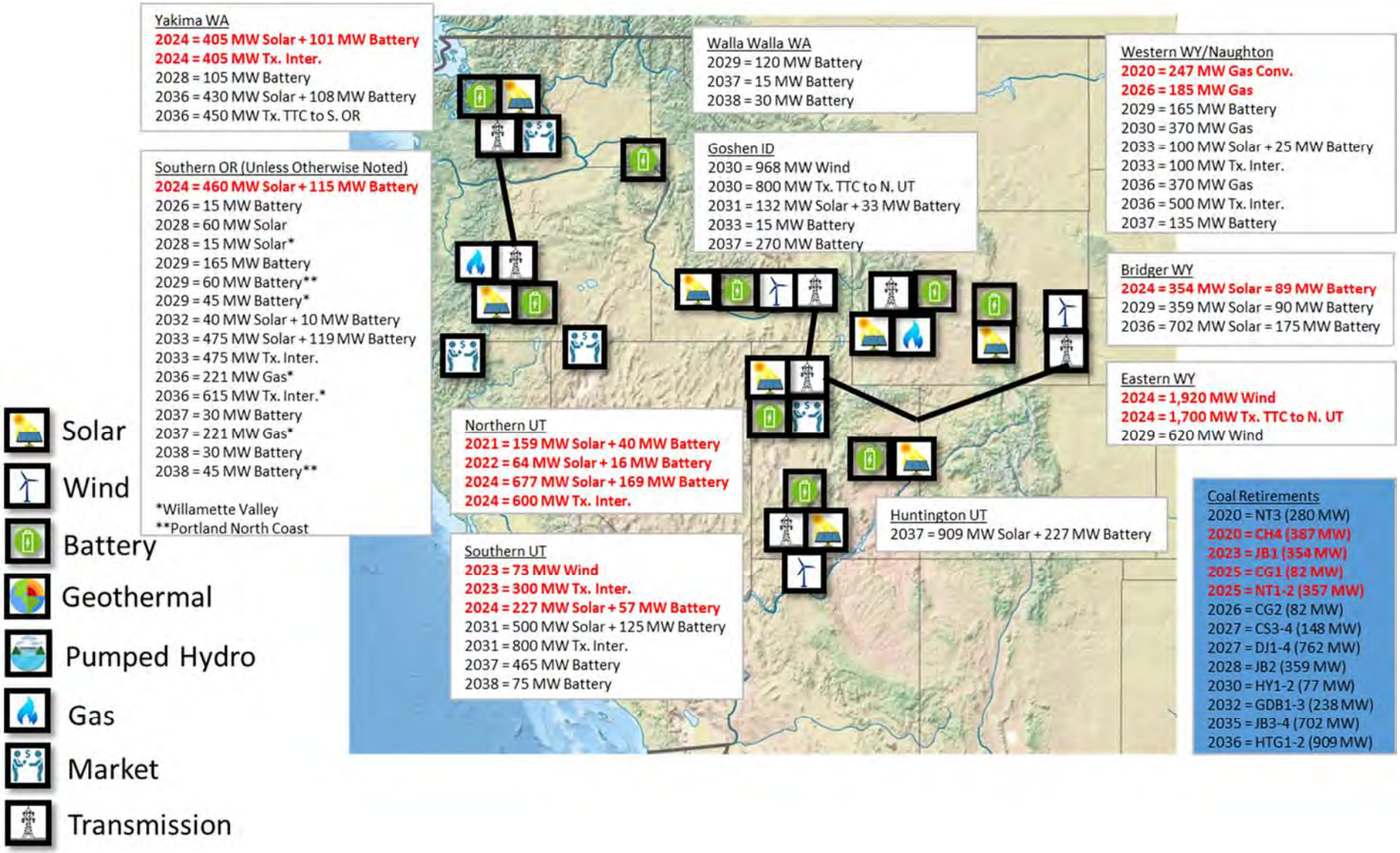
C-Case portfolio-development case P-47C is P-45C with Jim Bridger Units 3-4 retiring in 2035. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2035
Jim Bridger 4	Retire 2035
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2035 (P-47C)

P-47C (Jim Bridger 3 & 4 Retirement 2035)



C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-45C, and a sibling to P-47C, P-48C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 3 & 4 from 2037 to 2033. In addition, it was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

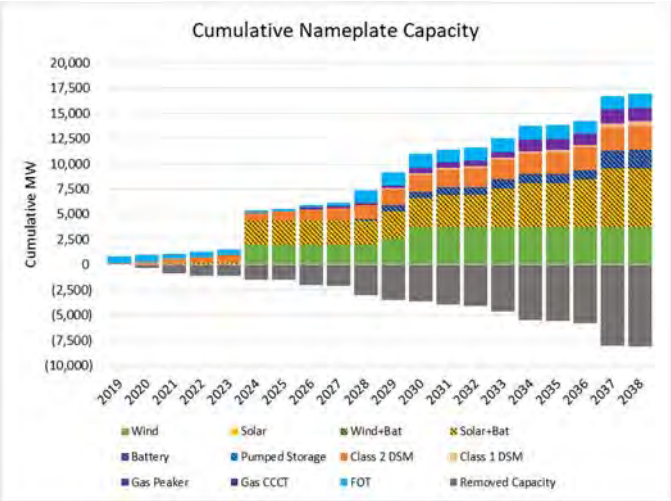
System Optimizer PVRR ($m) ***$21,482***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

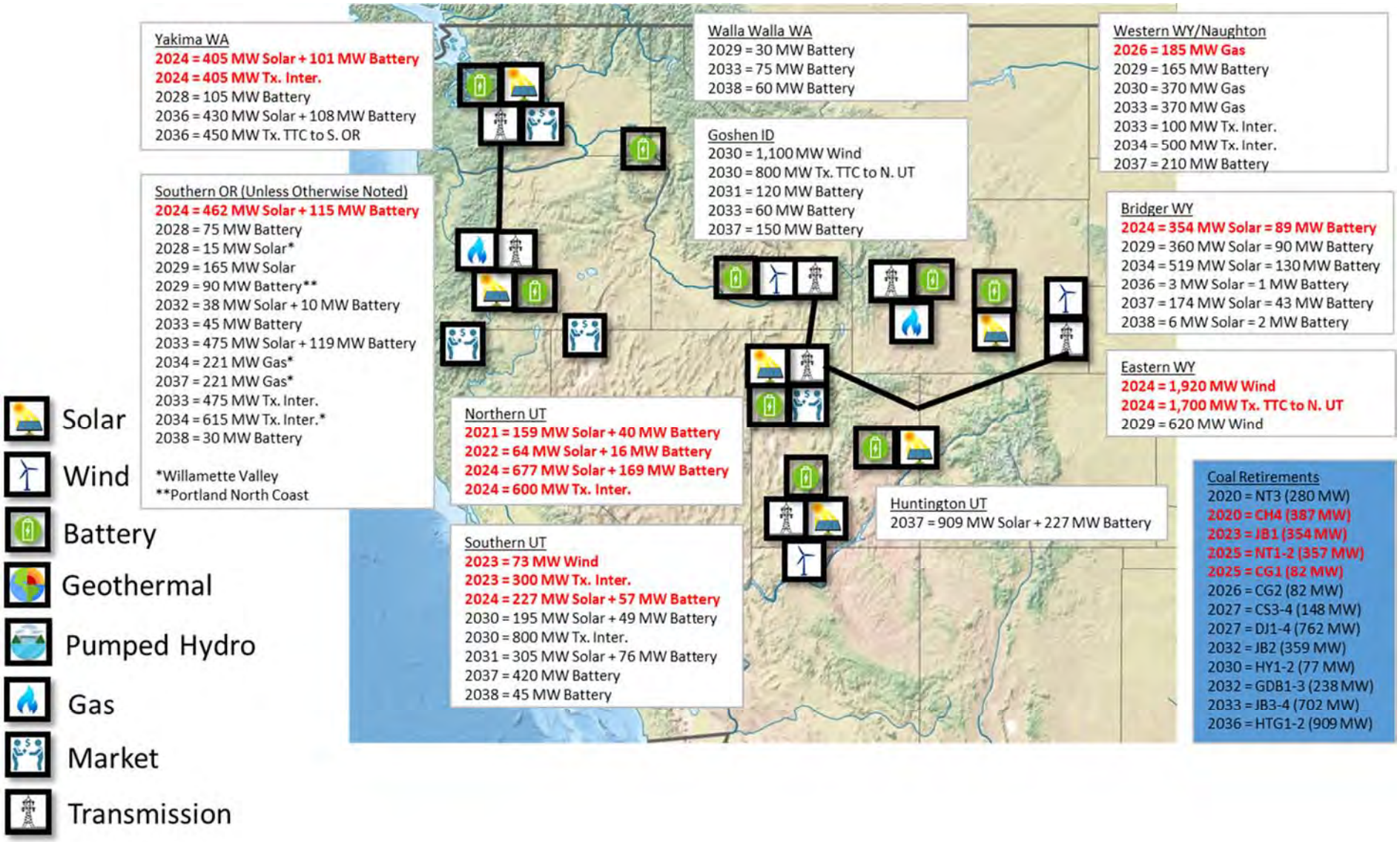
C-Case portfolio-development case P-48C is P-45C with Jim Bridger Units 3-4 retiring in 2033. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2033
Jim Bridger 4	Retire 2033
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2033 (P-48C)

P-48C (Jim Bridger 3 & 4 Retirement 2033)



Portfolio: Jim Bridger 1 &2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53C)

C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of P-53, P-53C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

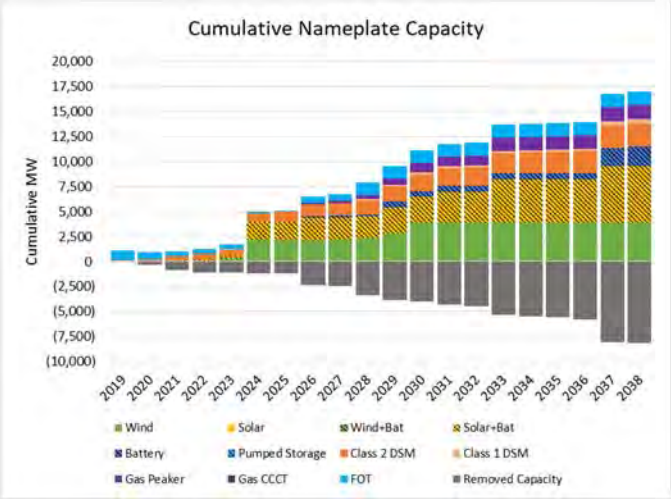
System Optimizer PVRR ($m) ***$21,450***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

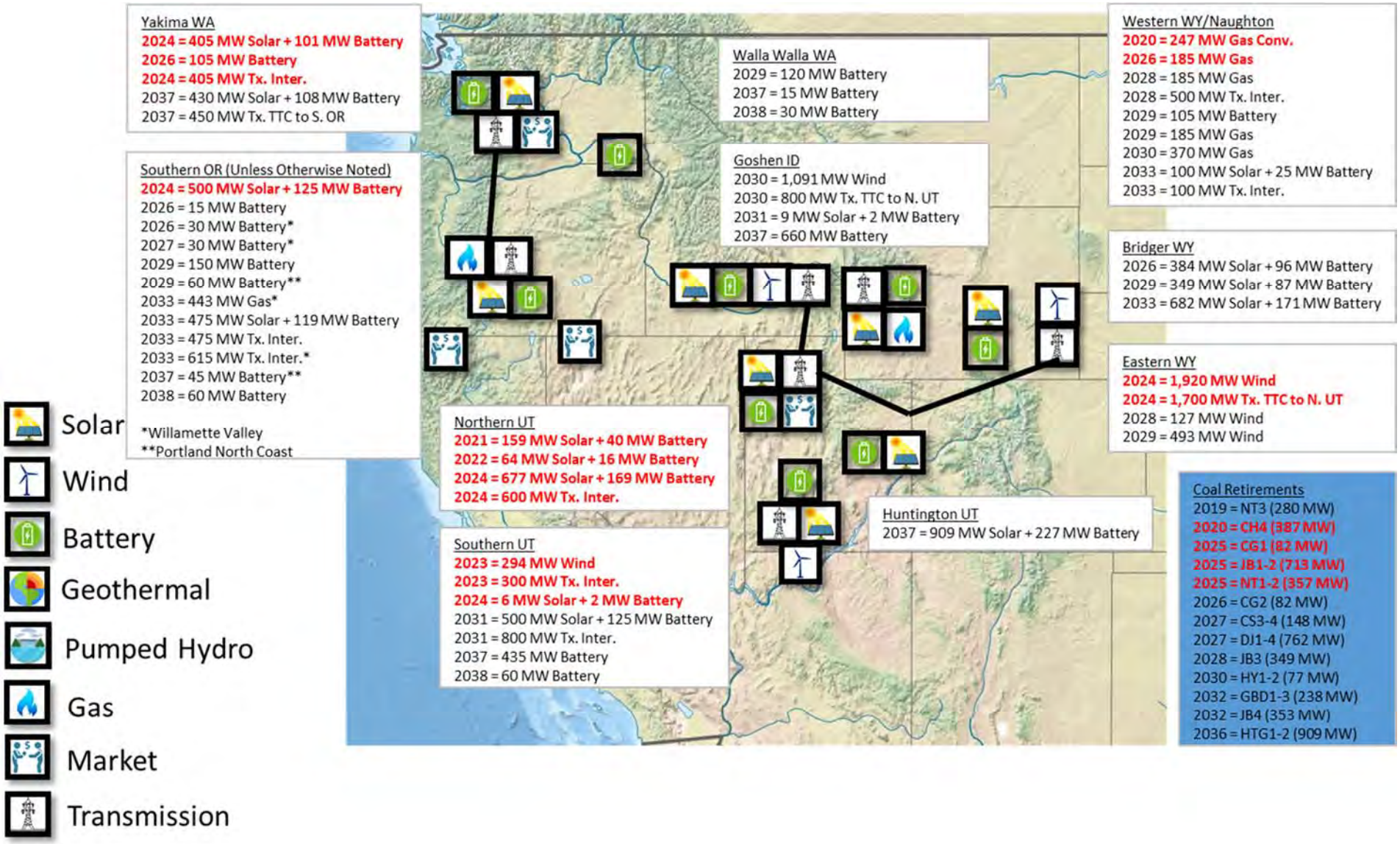
C-Case portfolio-development case P-53C is P-31C with Jim Bridger Units 1-2 retiring in 2025, Jim Bridger Unit 3 retiring in 2028, and Jim Bridger Unit 4 retiring in 2032. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2025
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2028
Jim Bridger 4	Retire 2032
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2019 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 &2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53C)

P-53C (P-31 with JB1-2 Retiring 2025, JB3 Retiring 2028, and JB4 Retiring 2032)



C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of sibling case P-53, P-53J23C has all of the same retirement assumptions except accelerates retirement of Jim Bridger Units 1 & 2 from 2025 to 2023. In addition, it was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

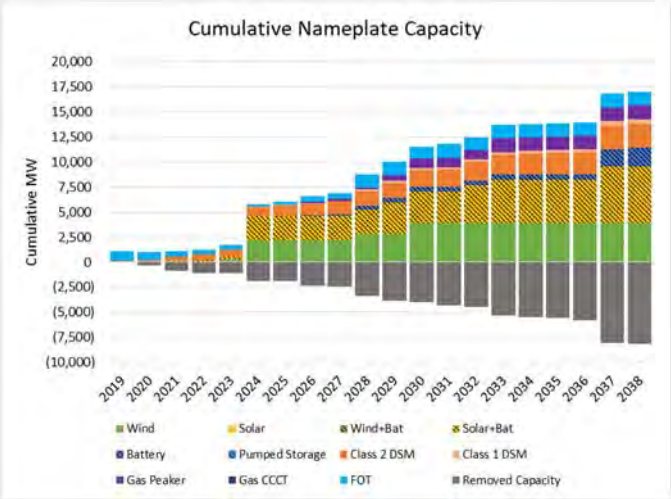
System Optimizer PVRR ($m) ***$21,394***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

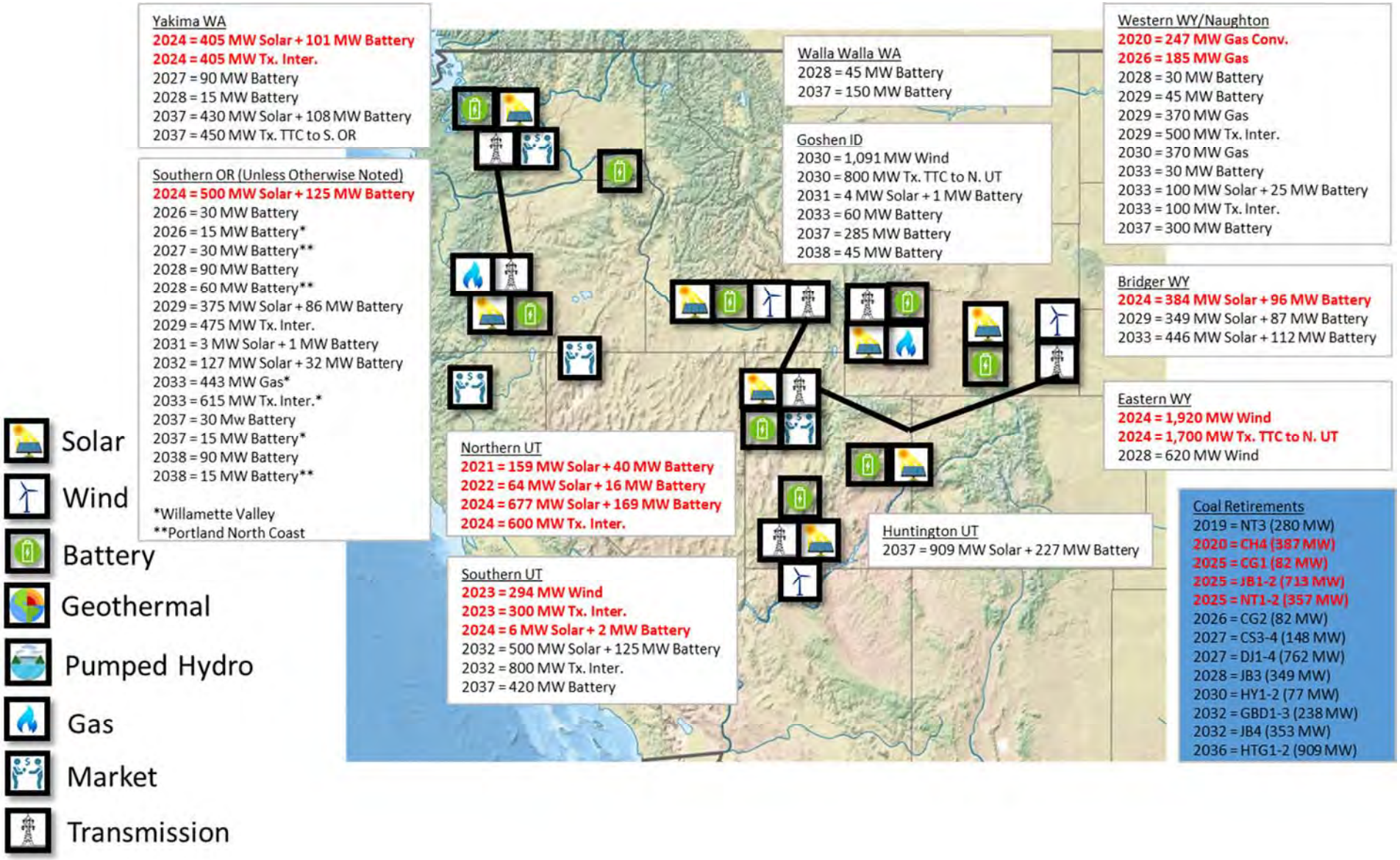
C-Case portfolio-development P-53J23C is P-53 with Jim Bridger Units 1 & 2 retiring in 2023. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2023
Jim Bridger 3	Retire 2028
Jim Bridger 4	Retire 2032
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2019 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 Retirement 2023 (P-53J23C)

P-53J23C (Jim Bridger 1 & 2 Retirement 2023)



C-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of P-54, P-54C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the initial 2023, 2030 and 2038, to include 2024 through 2029.

PORTFOLIO SUMMARY

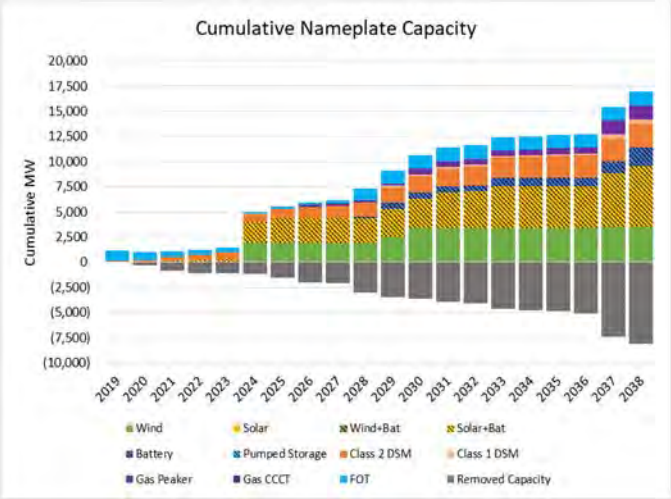
System Optimizer PVRR ($m) ***$21,450***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

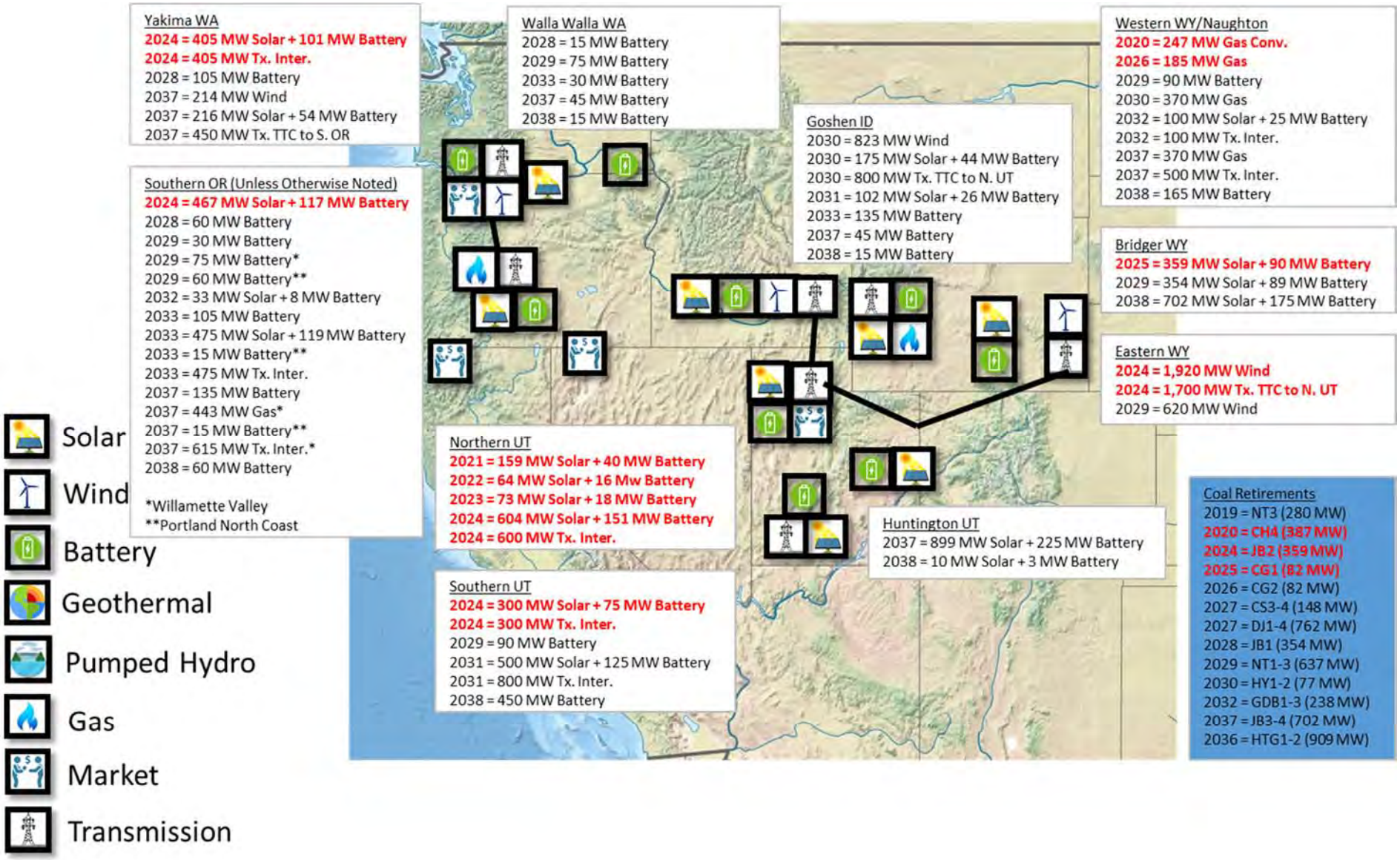
C-Case portfolio-development case P-54C is P-31 with Jim Bridger Unit 2 retiring in 2024. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2024
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3	Lg. GC 2019 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 2 Retirement 2024 (P-54C)

P-54C (Jim Bridger 2 Retirement 2024)



CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-36, P-36CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

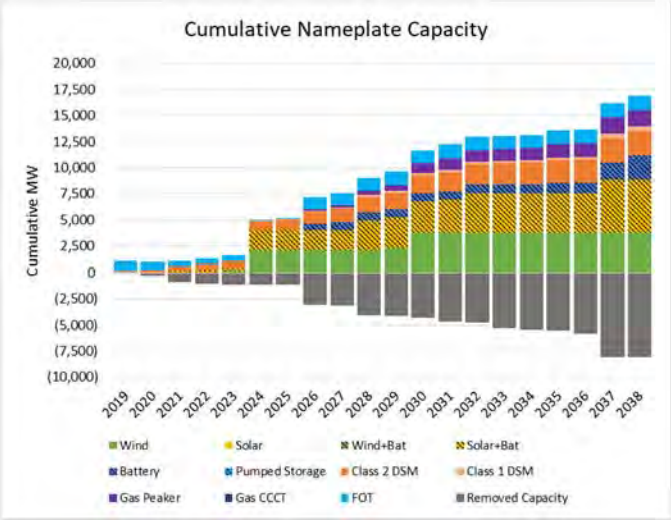
System Optimizer PVRR ($m) ***$21,553***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

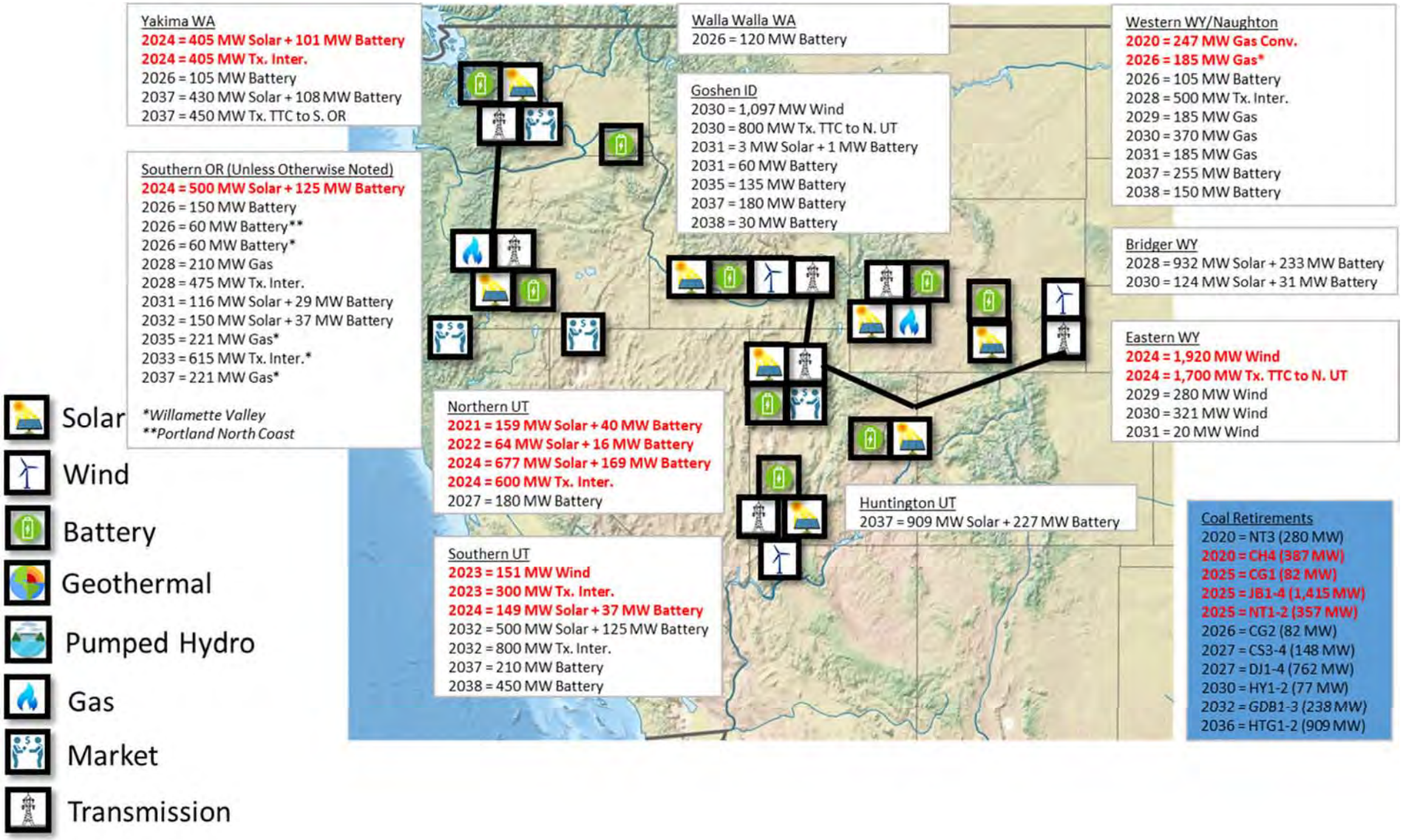
A variant of case P-14 and a variant of P-36, P-36CP has all of the same retirement assumptions except slows retirement of Jim Bridger Units 1-4 and Naughton Units 1 & 2 three years, from 2022 to 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2025
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2025
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger & Naughton 1&2 Retiring 2025 (P-36CP)

P-36CP (Jim Bridger 1 & 2 and Naughton 1 & 2 Retiring 2025)



CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-45, P-45CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

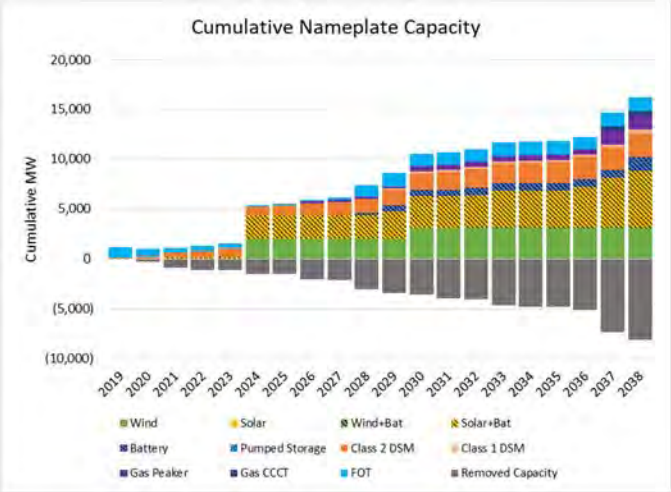
System Optimizer PVRR ($m) ***$21,480***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

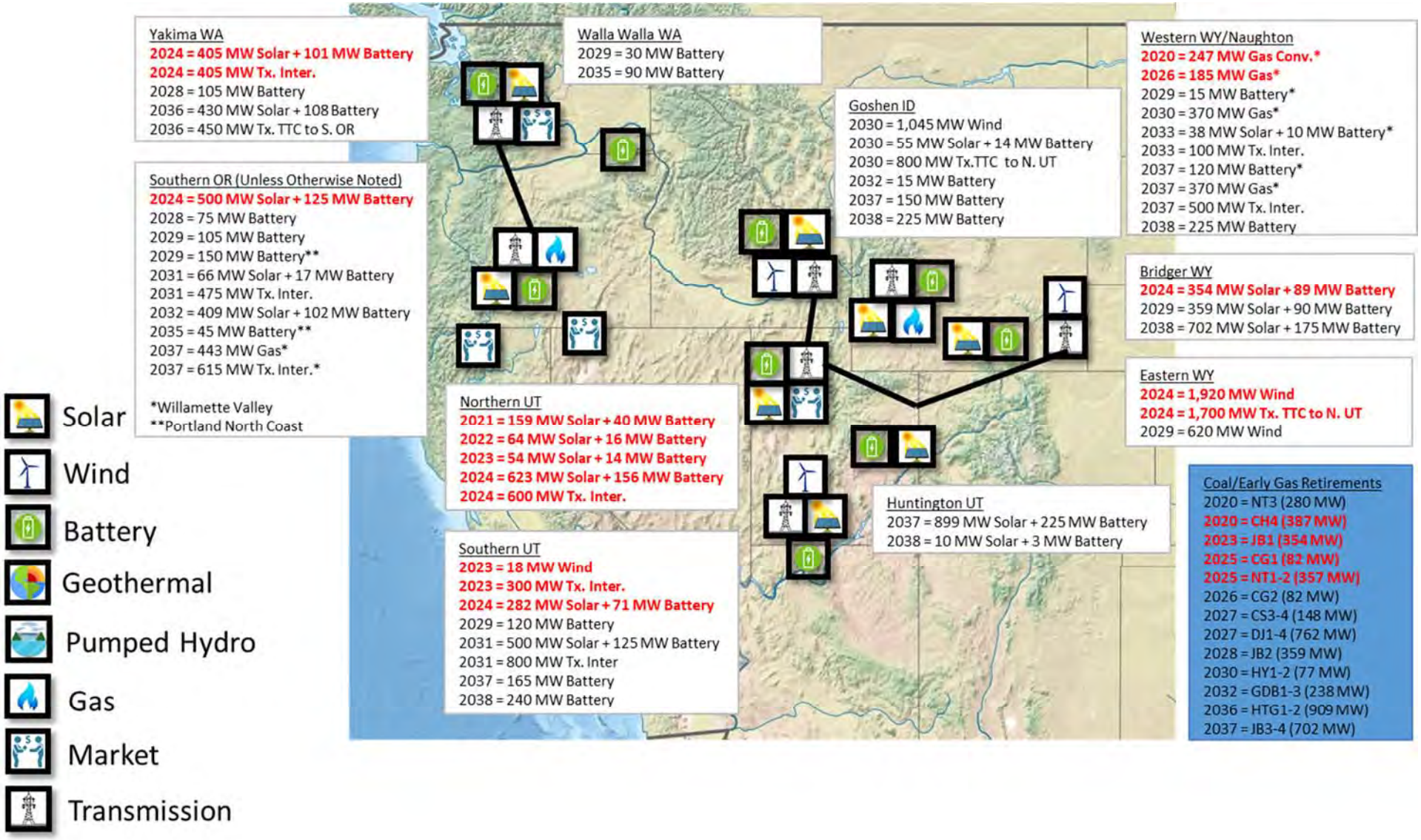
CP-Case portfolio-development case P-45CP is P-31 with Jim Bridger Unit 1 retiring in 2023 and Jim Bridger Unit 2 retiring in 2028. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2028 (P-45CP)

P-45C (Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2028)



CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-46, P-46CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

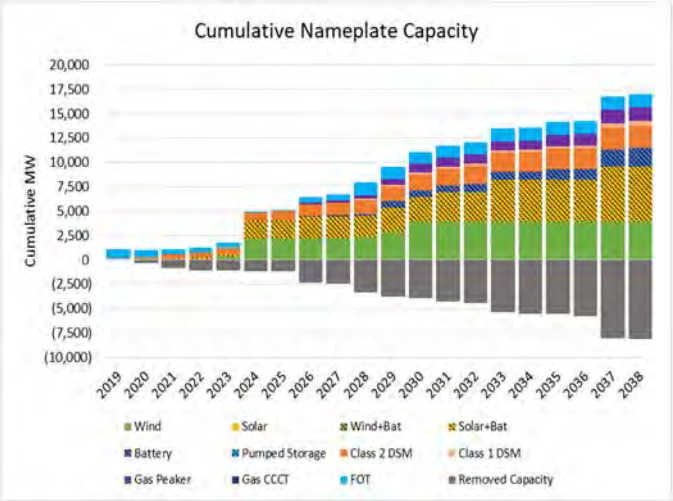
System Optimizer PVRR ($m) ***$21,460***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

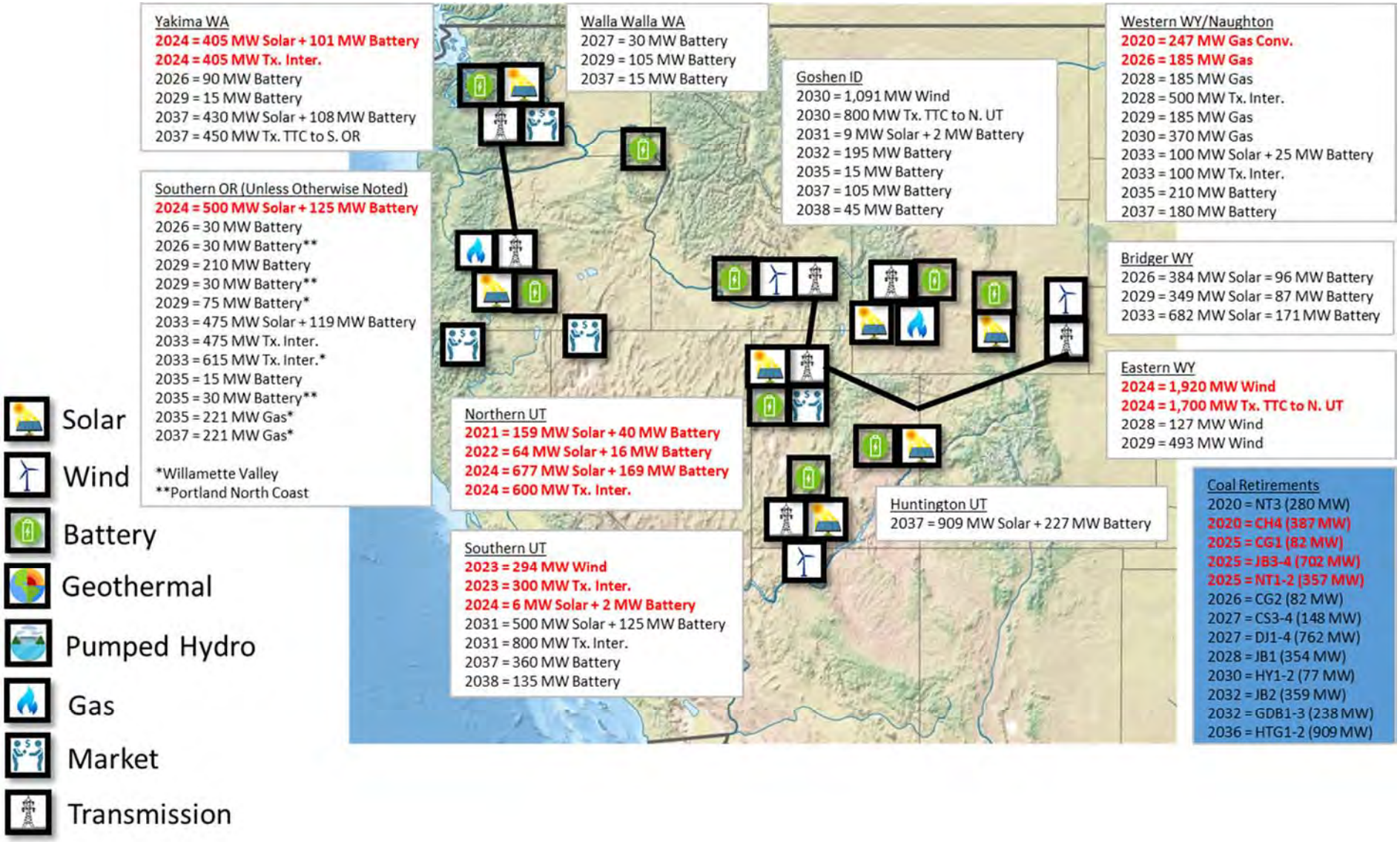
CP-Case portfolio-development case P-46C is P-31 with Jim Bridger Units 3 & 4 retiring in 2025. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2025
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2025 (P-46CP)

P-46C (Jim Bridger 3 & 4 Retirement 2025)



CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-46, P-46J23C has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

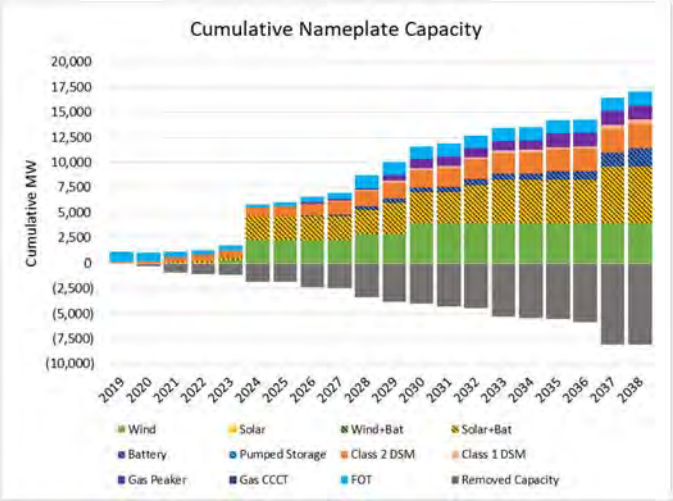
System Optimizer PVRR ($m) ***$21,402***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

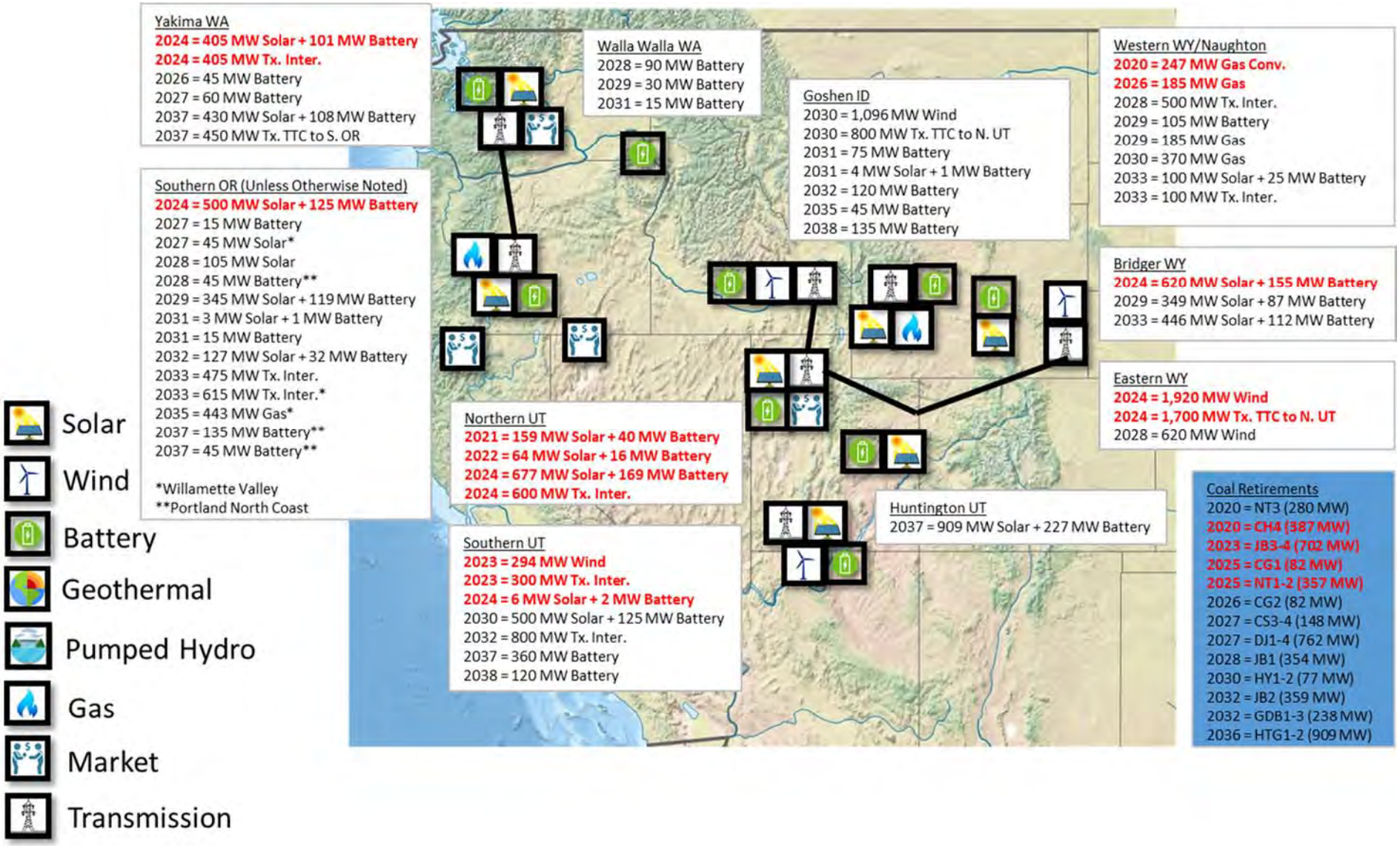
CP-Case portfolio-development case P-46J23C is P-46 with Jim Bridger Units 3 & 4 retiring in 2023. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2028
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2023
Jim Bridger 4	Retire 2023
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2023 (P-46J23CP)

P-46J23CP (Jim Bridger 3 & 4 Retirement 2023)



CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-47C, P-47CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

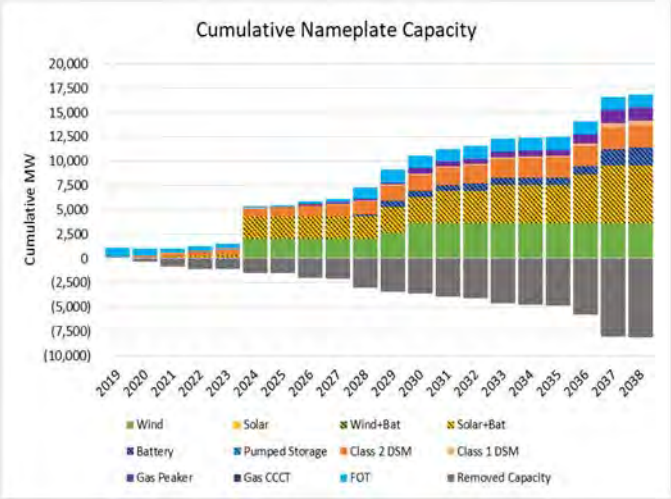
System Optimizer PVRR ($m) ***$21,469***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

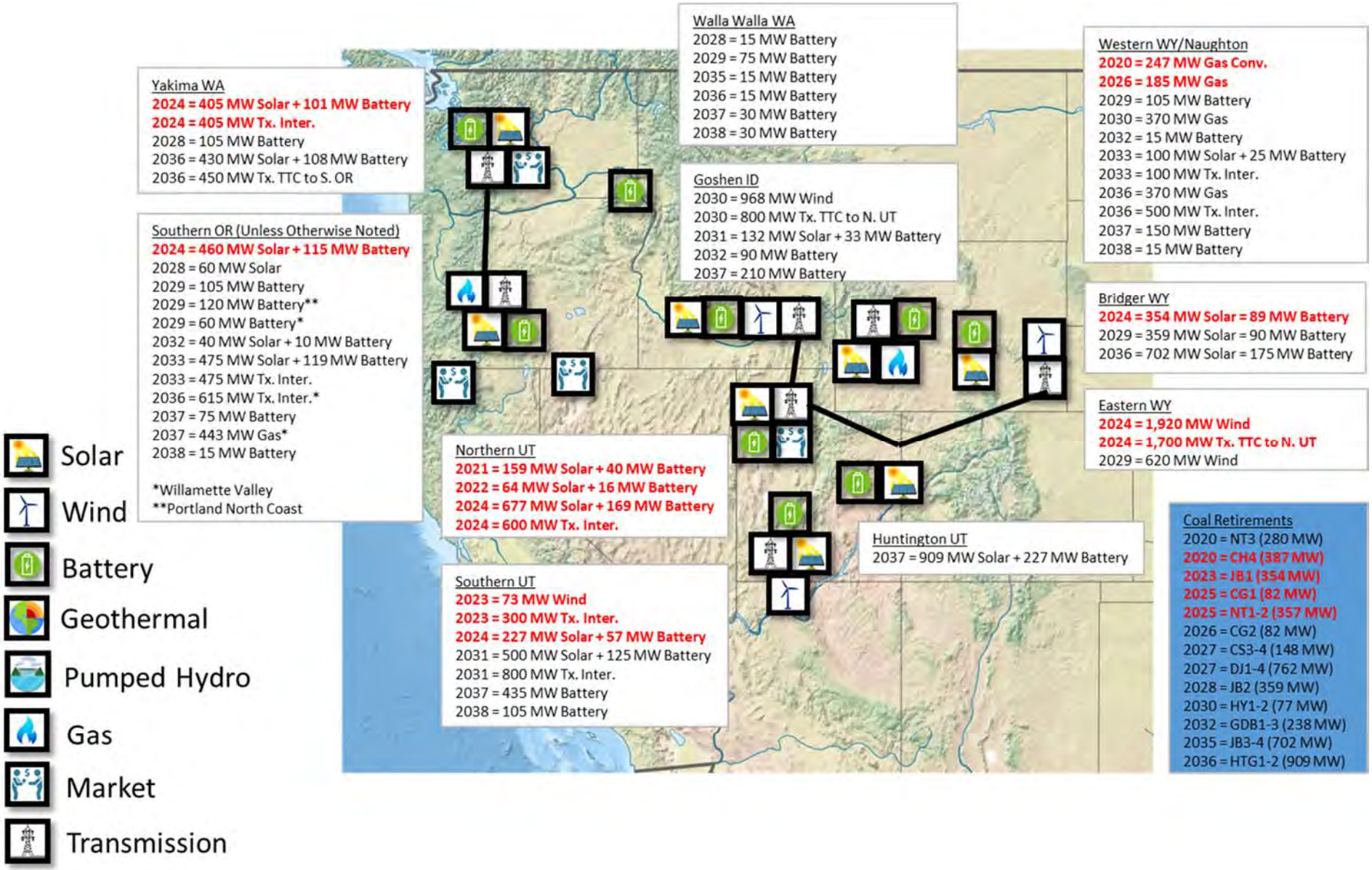
CP-Case portfolio-development case P-47CP is P-45CP with Jim Bridger Units 3-4 retiring in 2035. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2035
Jim Bridger 4	Retire 2035
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2035 (P-47CP)

P-47CP (Jim Bridger 3 & 4 Retirement 2035)



CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-48C, P-48CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

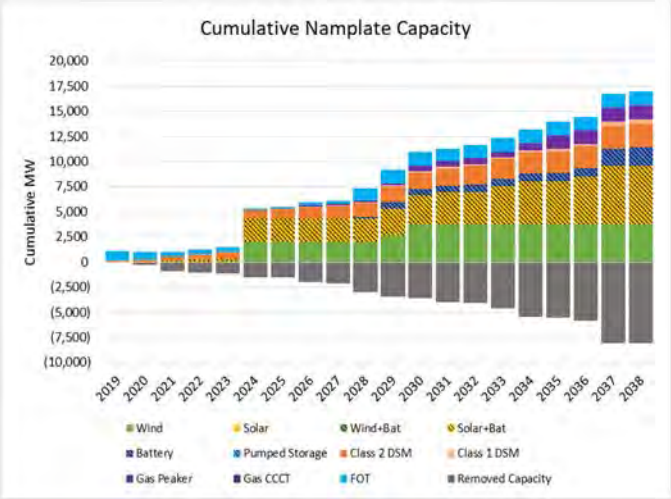
System Optimizer PVRR ($m) ***$21,457***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2036*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

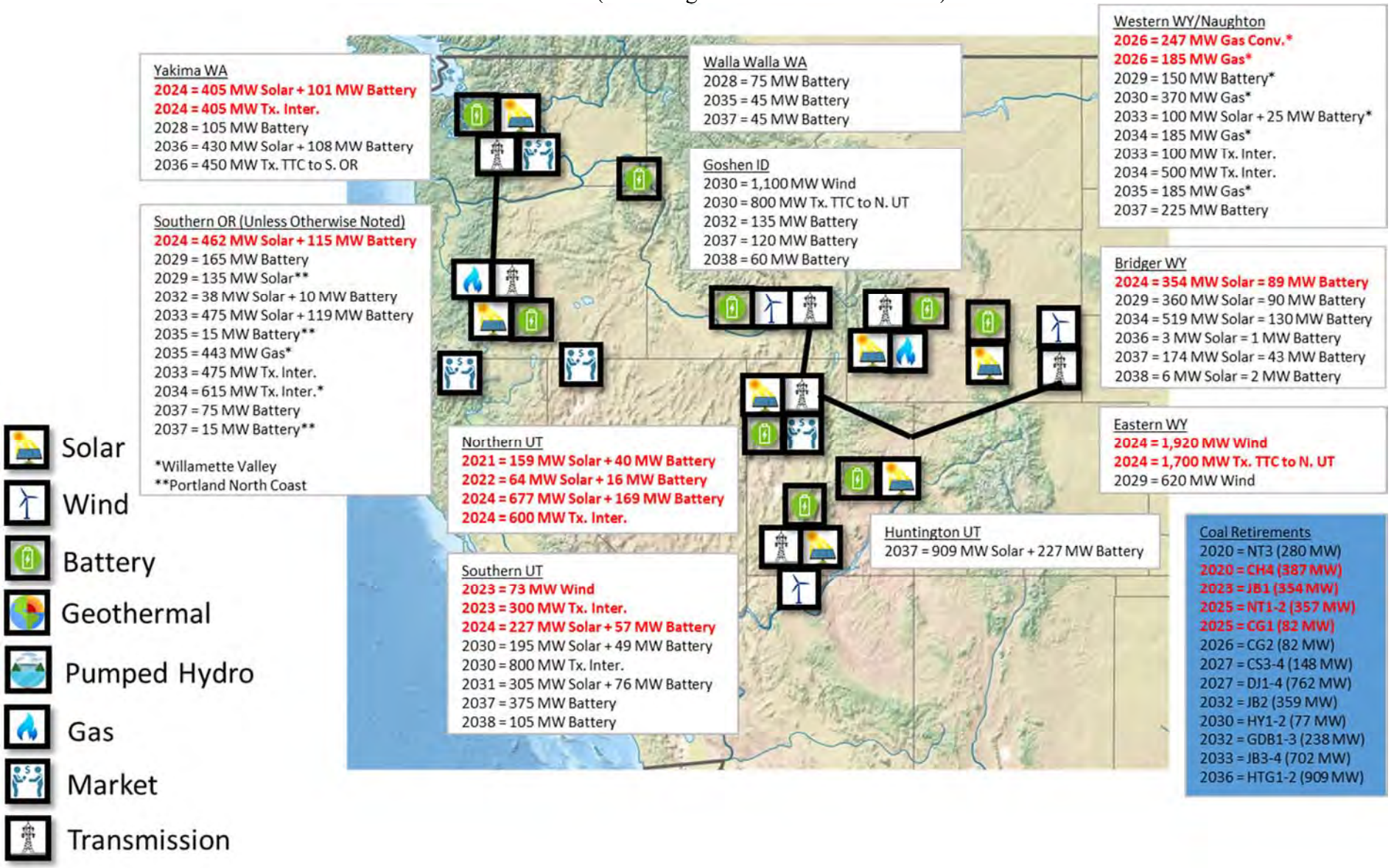
CP-Case portfolio-development case P-48CP is P-45CP with Jim Bridger Units 3 & 4 retiring in 2033. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2032
Jim Bridger 3	Retire 2033
Jim Bridger 4	Retire 2033
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Retirement 2033 (P-48CP)

P-48CP (Jim Bridger 3 & 4 Retirement 2033)



Portfolio: Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53CP)

CP-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-53C, P-53CP has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037.

PORTFOLIO SUMMARY

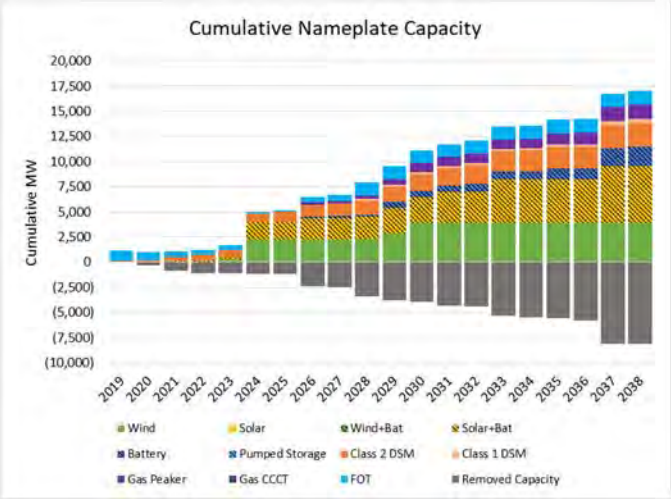
System Optimizer PVRR ($m) ***$21,479***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2037*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

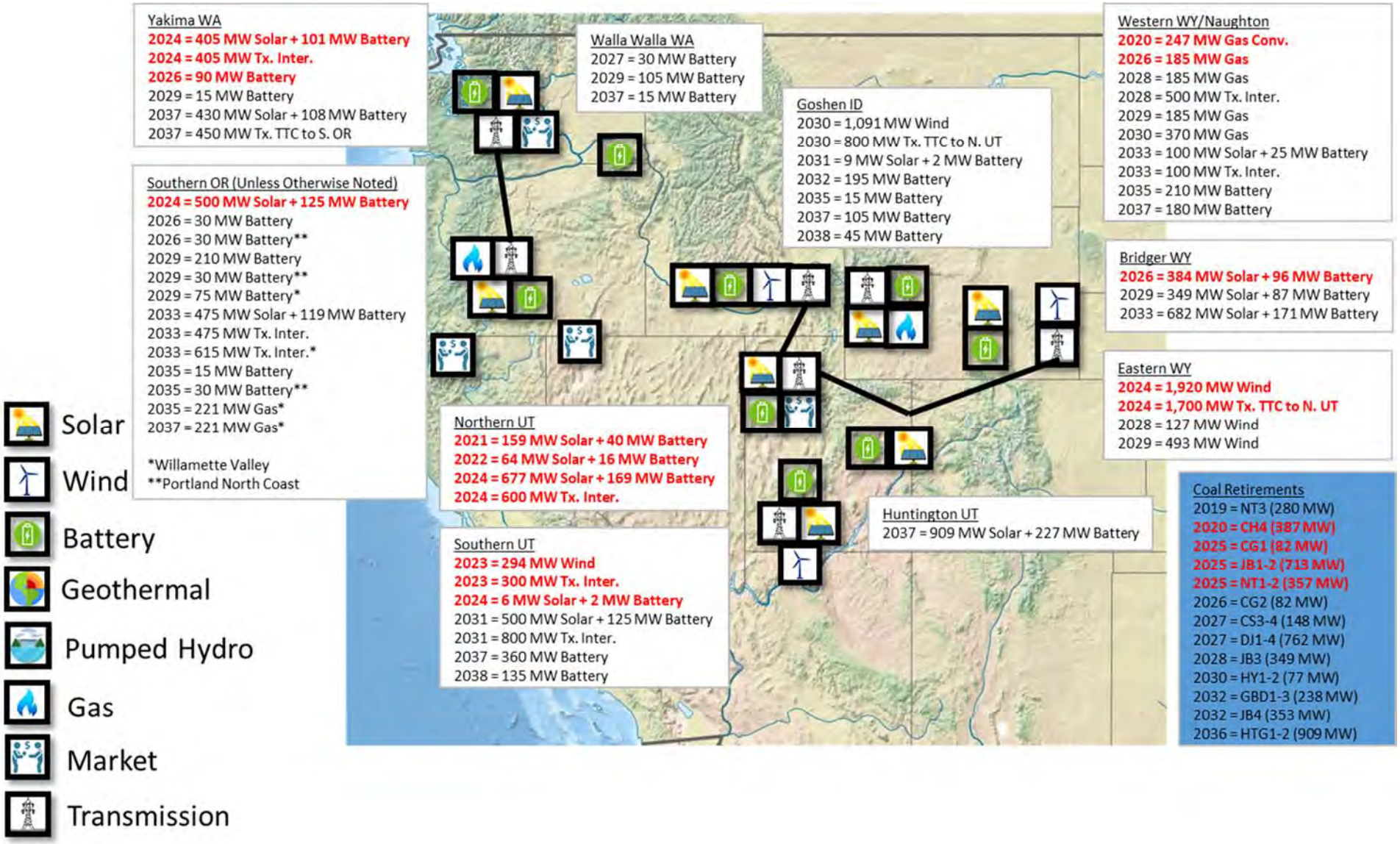
CP-Case portfolio-development case P-53CP is P-31 with Jim Bridger Units 1-2 retiring in 2025, Jim Bridger Unit 3 retiring in 2028, and Jim Bridger Unit 4 retiring in 2032. Full retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2025
Jim Bridger 2	Retire 2025
Jim Bridger 3	Retire 2028
Jim Bridger 4	Retire 2032
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2019 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032 (P-53CP)

P-48CP (Jim Bridger 1 & 2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032)



No Gas-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-45CNW, P-29 is a C-Prime case and has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037. In addition, no new gas resources were allowed.

PORTFOLIO SUMMARY

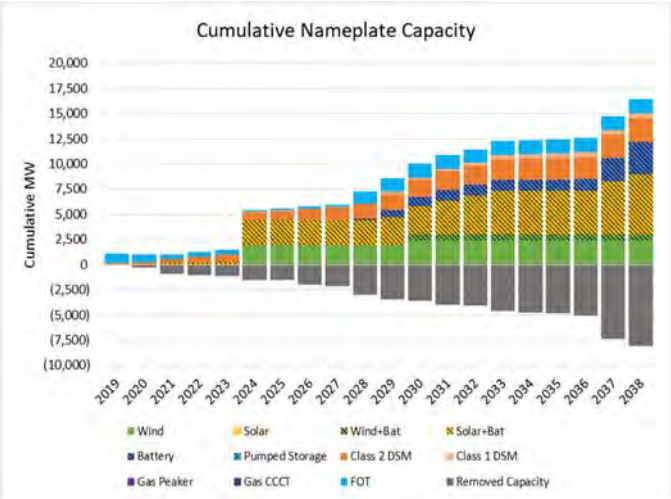
System Optimizer PVRR ($m) ***$21,798***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*
Yakima – to – S. Oregon/California	*2033*	*450*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

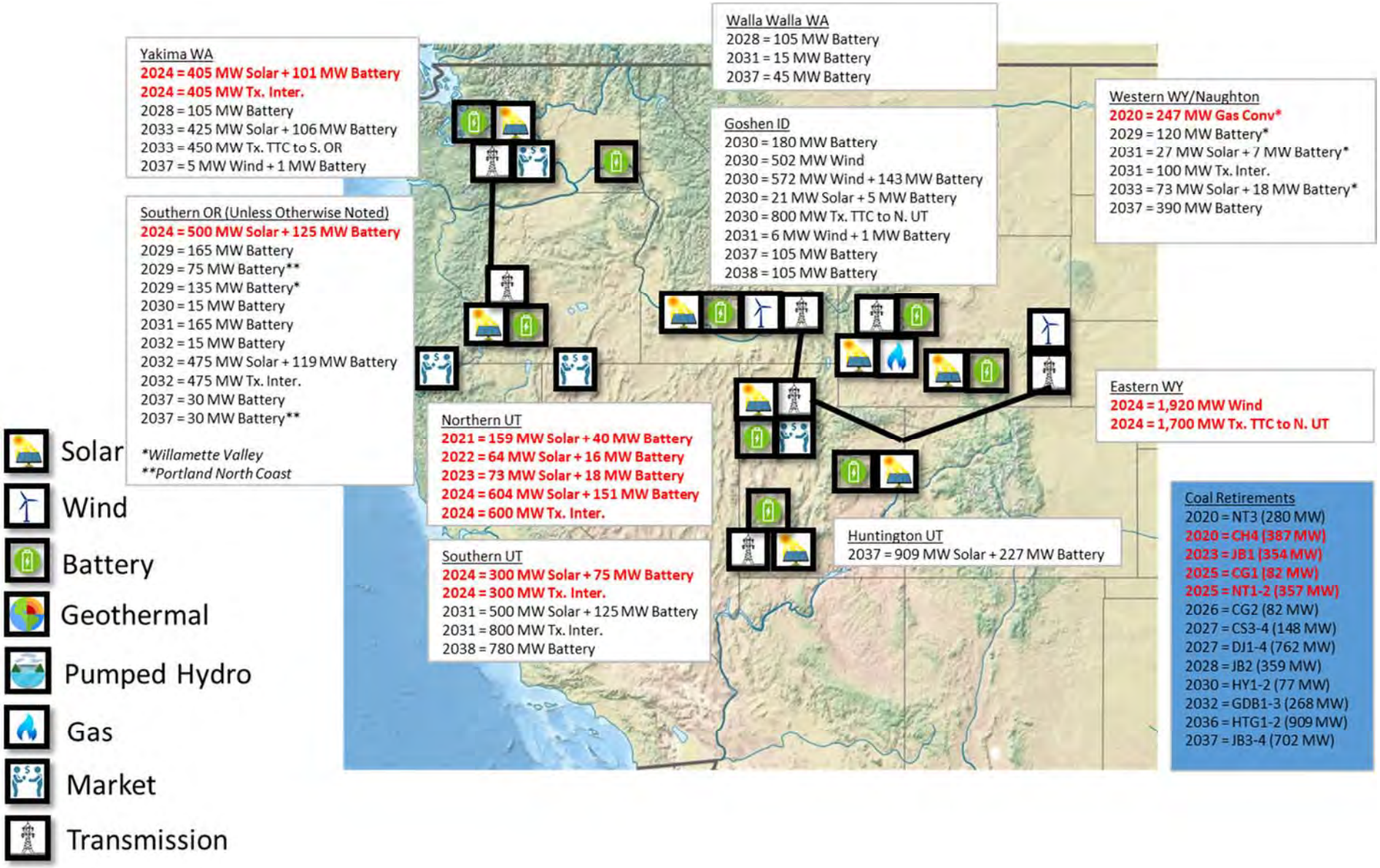
No Gas-Case portfolio-development case P-29 is P-45CNW with no new gas option. Retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: P-45CNW, No New Gas Option (P-29)

P-429 (P-45CNW, No New Gas Option)



No Gas-Cases Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

A variant of case P-29, and a variant of P-45CNW, P-29PS is a C-Prime case and has all of the same retirement assumptions except was processed through Planning and Risk Deterministic runs for reliability beyond the C-Cases' 2023 through 2030 and 2038, to include 2031 through 2037. In addition to no new gas resource options allowed, it required the addition of pumped hydro.

PORTFOLIO SUMMARY

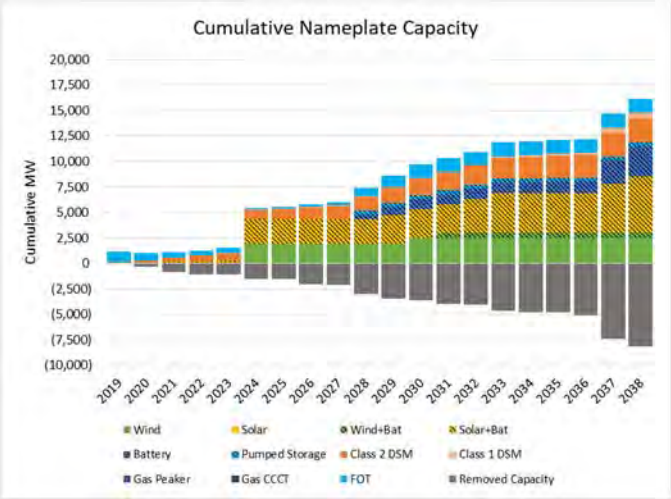
System Optimizer PVRR ($m) ***$21,970***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus WY – to – Utah S, Expansion	*2024*	*1,700*
Goshen – to – Utah N, Expansion	*2030*	*800*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as nameplate capacity, are summarized in the figure below.



Retirement Assumptions

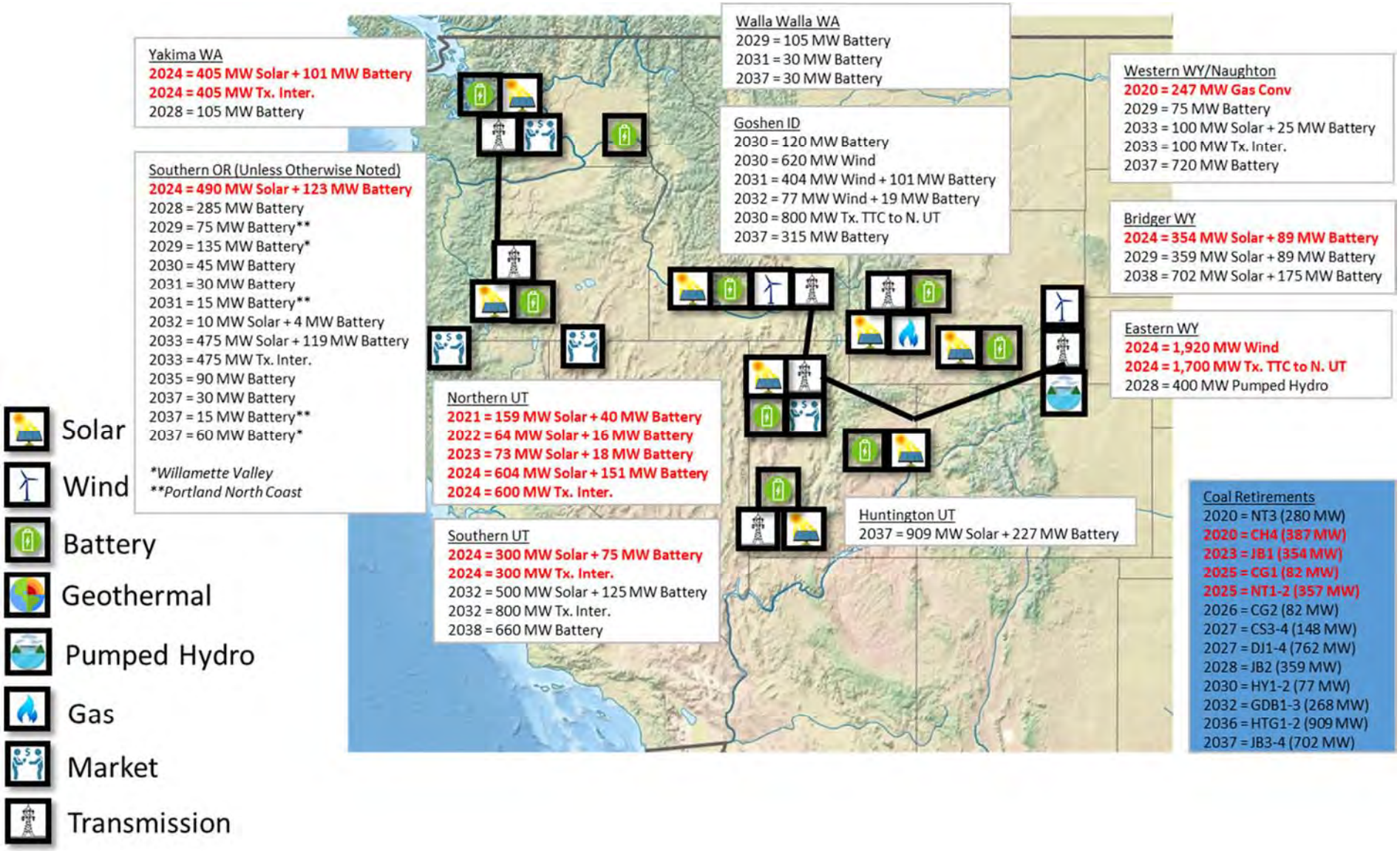
No Gas-Case portfolio-development case P-29PS is P-45CNW with no new gas allowed, but adds pumped hydro storage. Retirement assumptions are summarized in the following table.

Unit	Description
Cholla 4	Retire 2020
Colstrip 3	Retire 2027
Colstrip 4	Retire 2027
Craig 1	Retire 2025
Craig 2	Retire 2026
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	Retire 2027
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Hayden 1	Retire 2030
Hayden 2	Retire 2030
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	Retire 2023
Jim Bridger 2	Retire 2028
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3	Lg. GC 2020 Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: P-45CNW, No New Gas Option With Pumped Hydro Storage (P-29PS)

P-429 (P-45CNW, No New Gas Option with Pumped Hydro Storage)



Energy Gateway Portfolio-Development Fact Sheets

CASE ASSUMPTIONS

Description

Gateway Study P-22CNW includes Segment D.3 – Populus to Bridger/Anticline. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

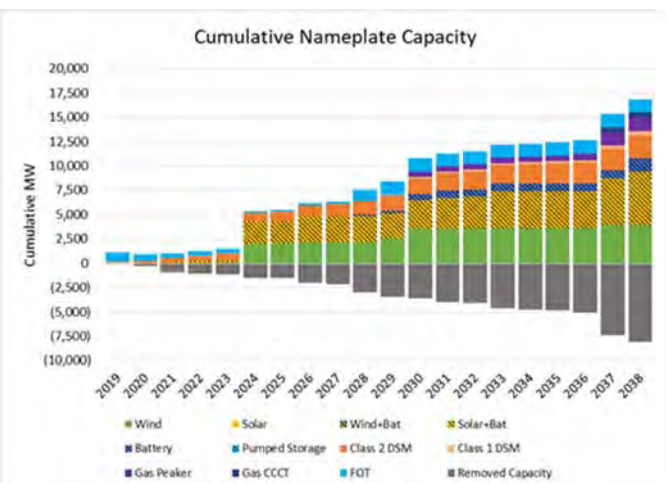
System Optimizer PVRR ($m) ***$21,886***

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2037*	*450*

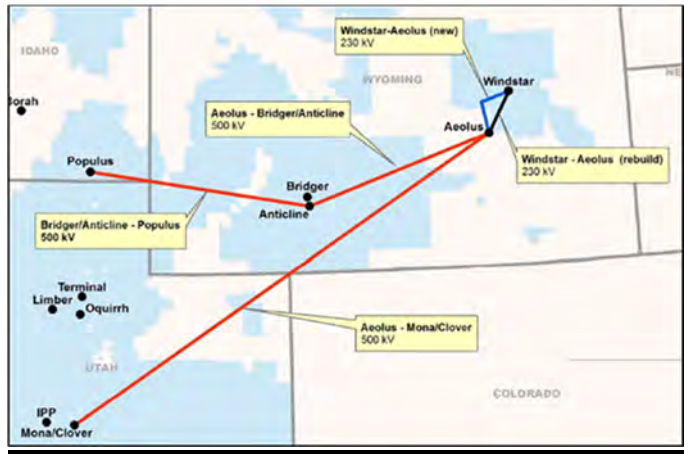
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



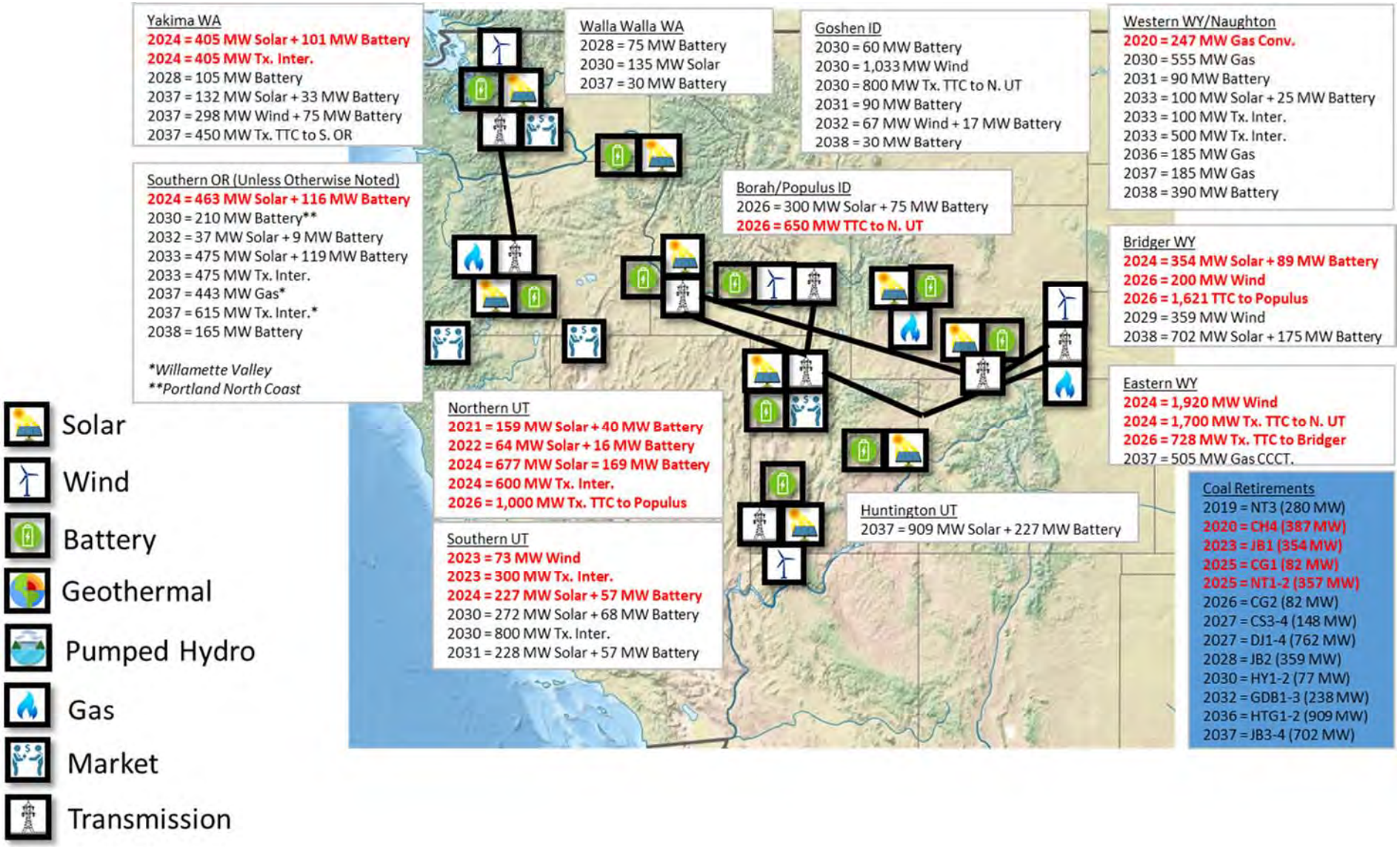
Transmission

Transmission path is shown in the map below



Portfolio: Energy Gateway Segment D3 (P-22)

P-22 (Energy Gateway Segment D3)



Energy Gateway Portfolio-Development Fact Sheets

CASE ASSUMPTIONS

Description

Gateway Study P-23CNW includes all gateway options for System Optimizer to choose. This sensitivity is a variant of the case P-36C.

PORTFOLIO SUMMARY

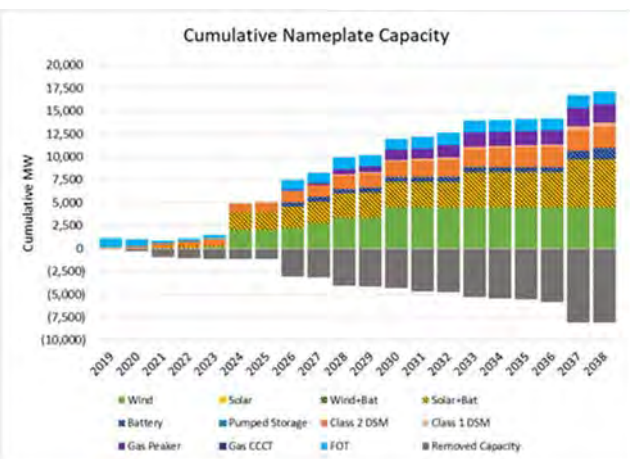
System Optimizer PVRR ($m) ***$22,151***

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2037*	*450*

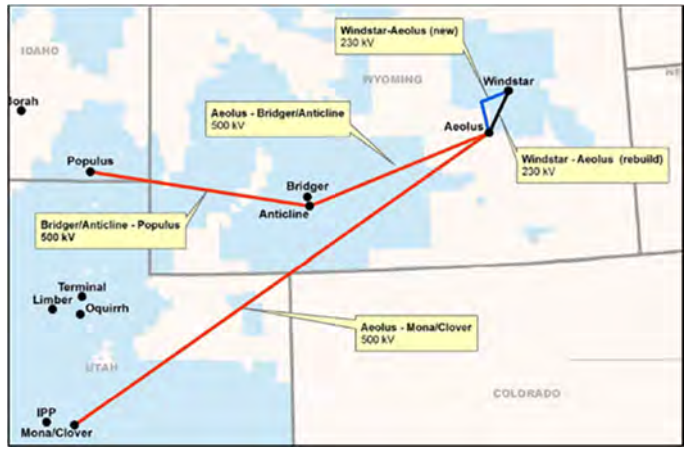
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



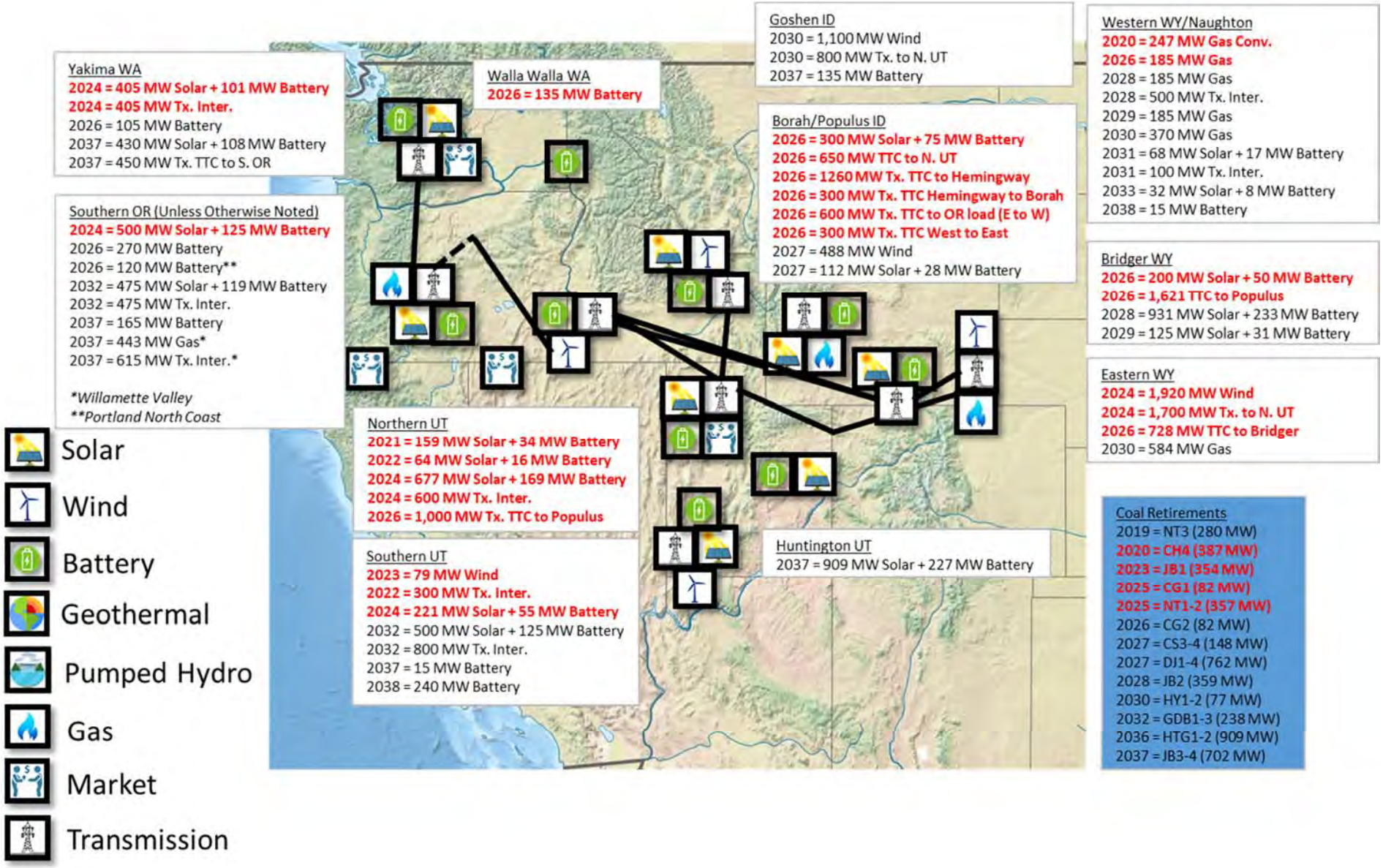
Transmission

Transmission path is shown in the map below



Portfolio: Energy Gateway Segment D1 and F (P-23)

P-23 (Energy Gateway Segment D1 and F)



Energy Gateway Portfolio-Development Fact Sheets

CASE ASSUMPTIONS

Description

Gateway Study P-25CNW includes Segment D.3 – Populus to Bridger/Anticline, along with Segment E, Hemingway – Cedar Hill and Segment H, Boardman - Hemingway. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

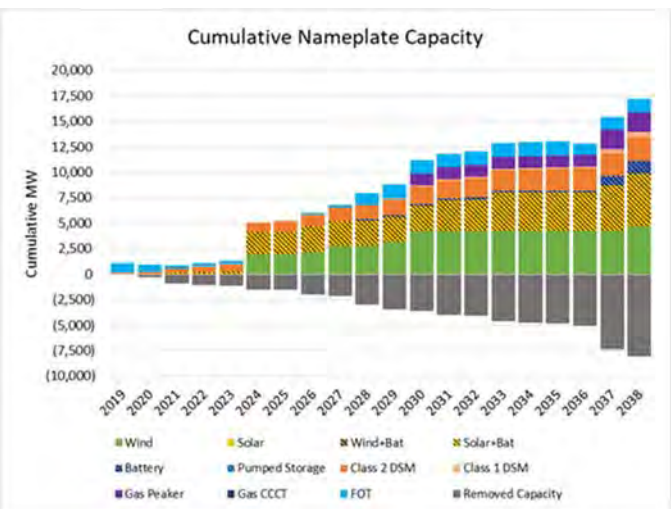
System Optimizer PVRR ($m) ***$22,273***

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2038*	*450*

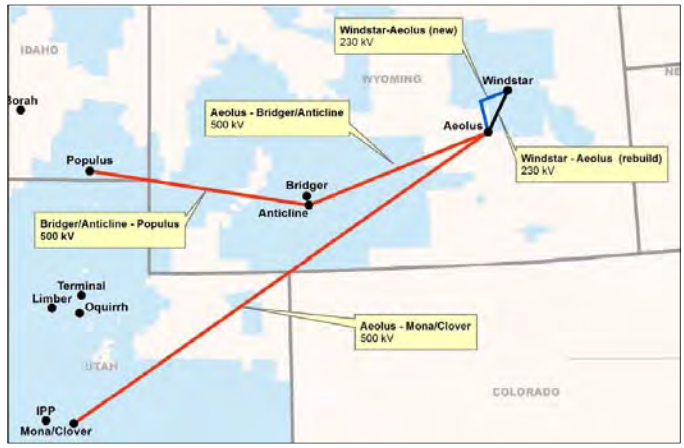
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



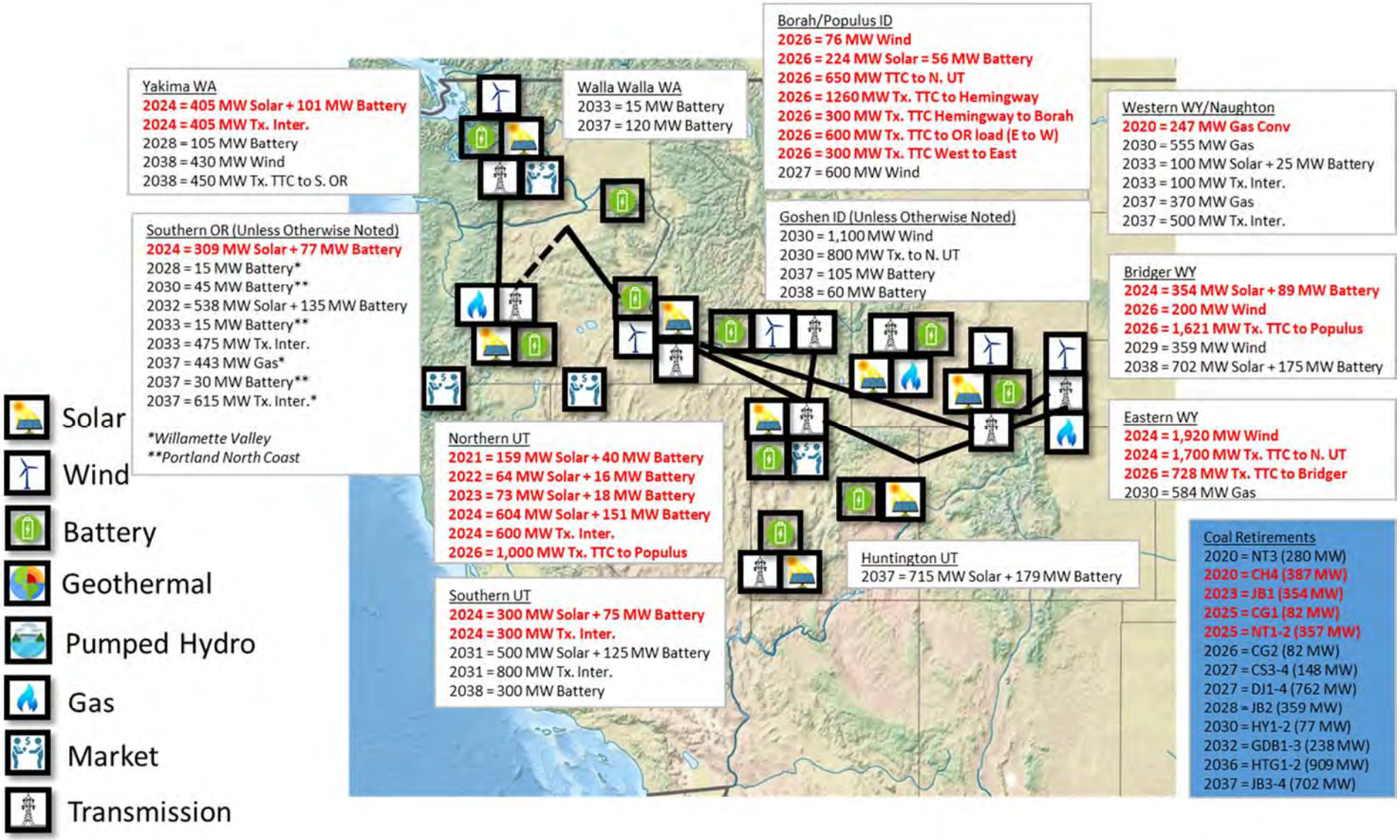
Transmission

Transmission path is shown in the map below



Portfolio: Energy Gateway Segment D3, E, and H (P-25)

P-25 (Energy Gateway Segment D3, E, and H)



Energy Gateway Portfolio-Development Fact Sheets

CASE ASSUMPTIONS

Description

Gateway Study P-26CNW includes Segment, Boardman - Hemingway. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

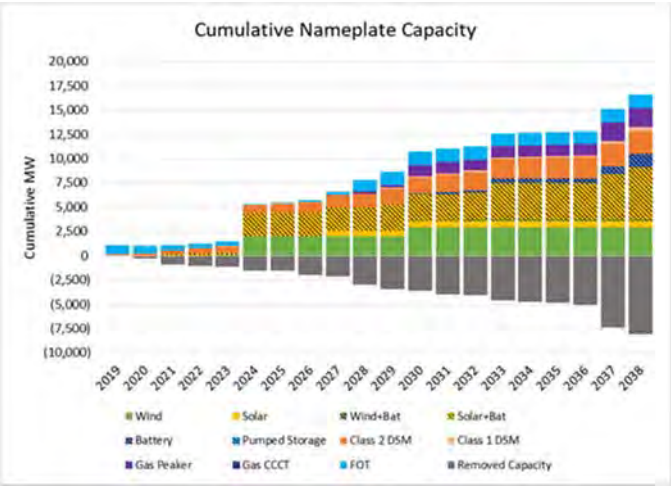
System Optimizer PVRR ($m) ***$21,579***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*

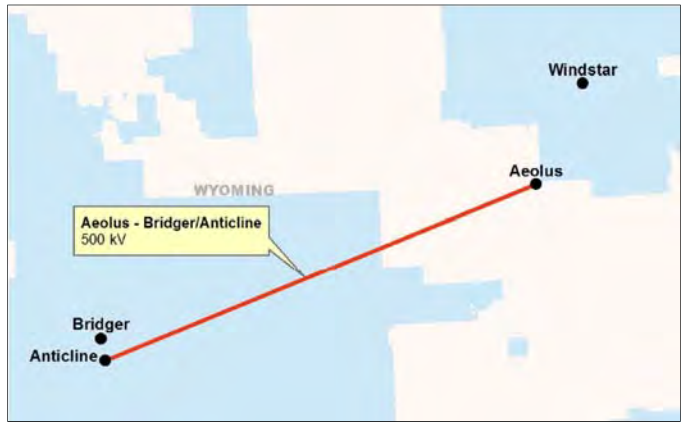
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



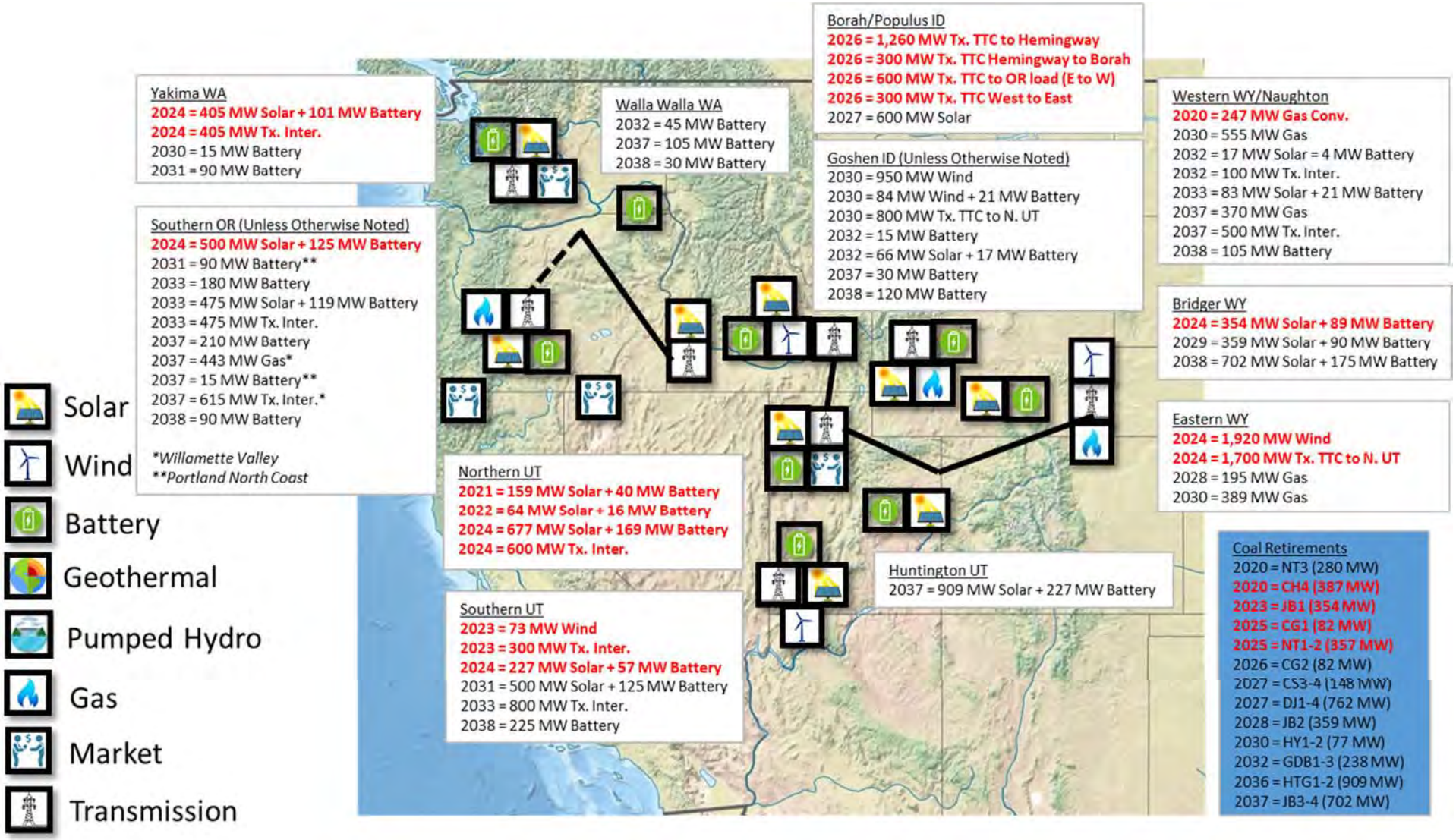
Transmission

Transmission path is shown in the map below



Portfolio: Energy Gateway Segment H (P-26)

P-26 (Energy Gateway Segment H)



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The low load forecast sensitivity reflects pessimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The low industrial load forecast is taken from 5th percentile. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

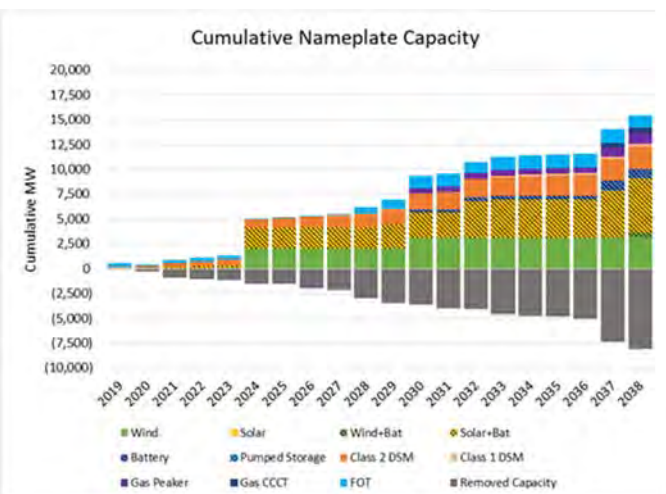
System Optimizer PVRR ($m) ***$20,617***

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Walla Walla- to – Yakima	*2037*	*200*
Portland N Coast - to - Willamette Valley	*2038*	*450*

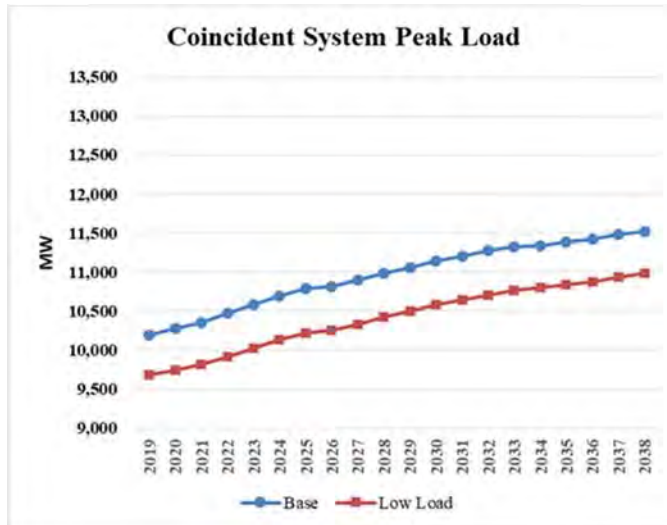
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

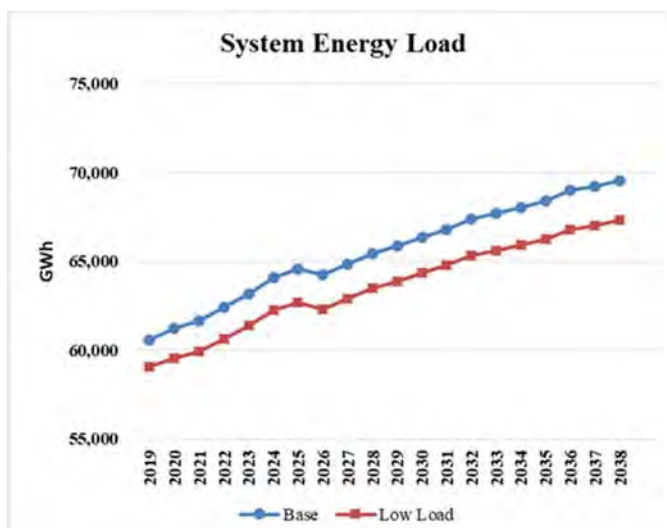


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The high load forecast sensitivity reflects optimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The high industrial load forecast is taken from 95th percentile. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

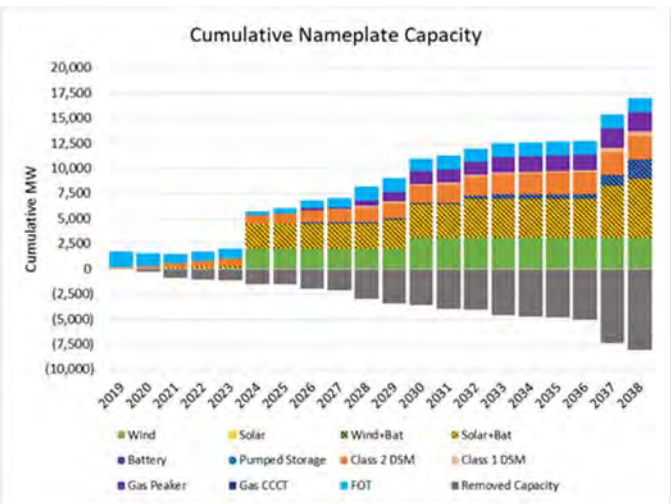
System Optimizer PVRR ($m) ***$22,602***

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2037*	*450*

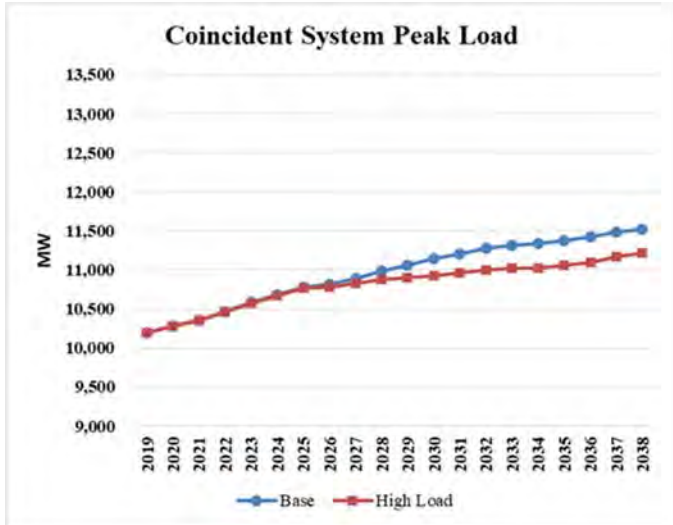
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

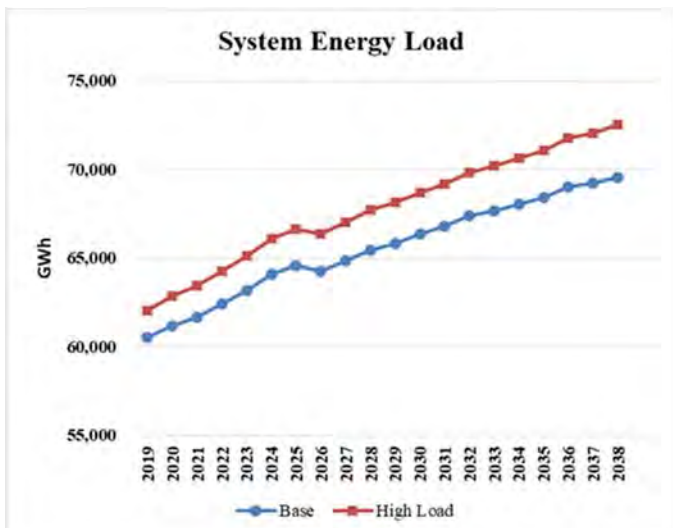


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The 1-in-20 peak load sensitivity is a five percent probability extreme weather scenario. 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. This sensitivity is based on 1-in-20 peak weather for July in each state. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

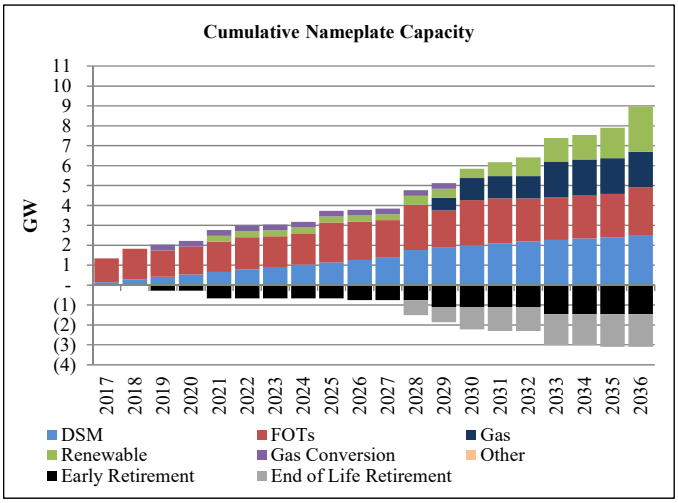
System Optimizer PVRR ($m) ***$21,634***

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2036*	*450*

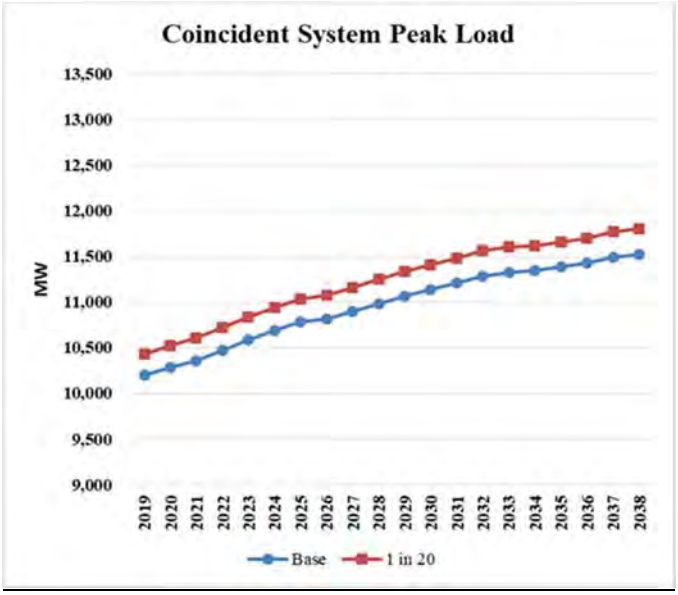
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

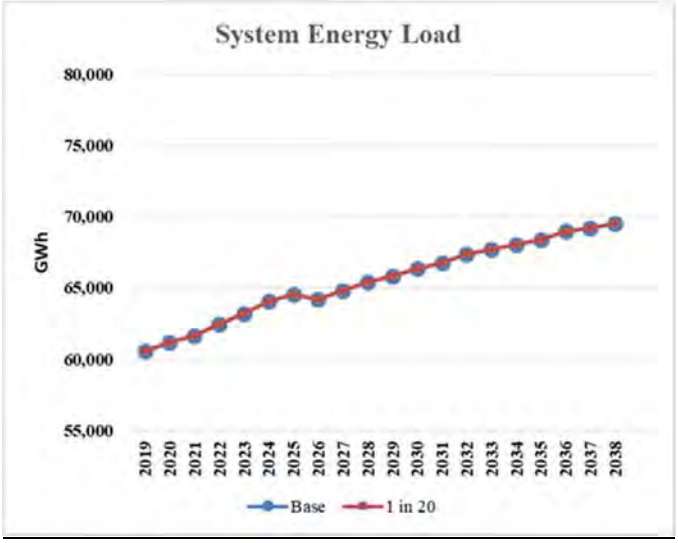


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources. Energy load forecast is identical to Base Case.



The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The low private generation sensitivity reflects reductions in technology costs, reduced technology performance levels, and lower retail electricity rates, compared to base penetration levels incorporating annual reductions in technology costs. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

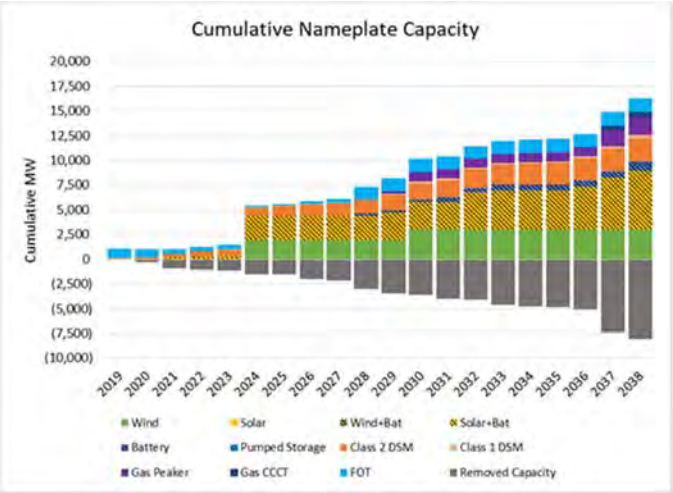
System Optimizer PVRR ($m) ***$21,758***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2036*	*450*
Willamette Valle - to – S. OR/CA	*2037*	*1500*

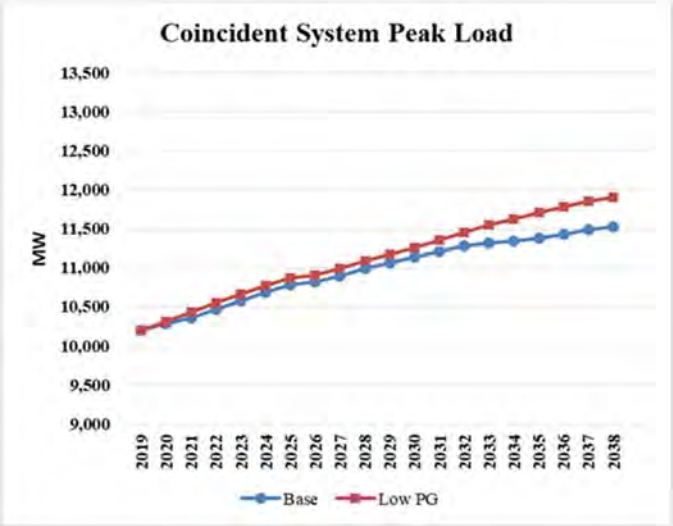
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

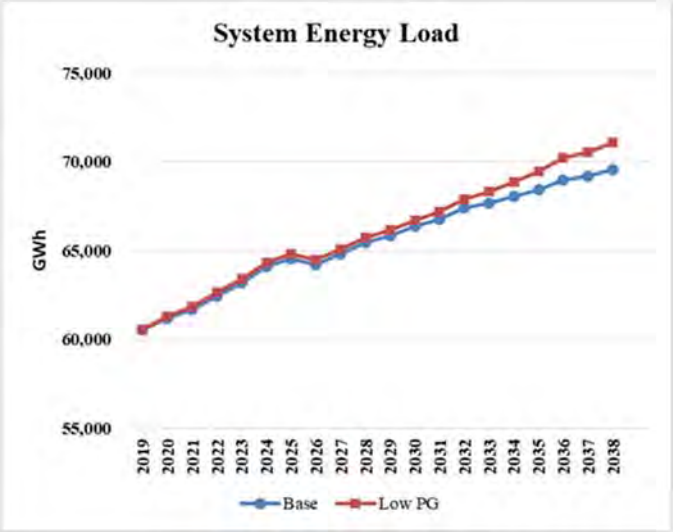


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



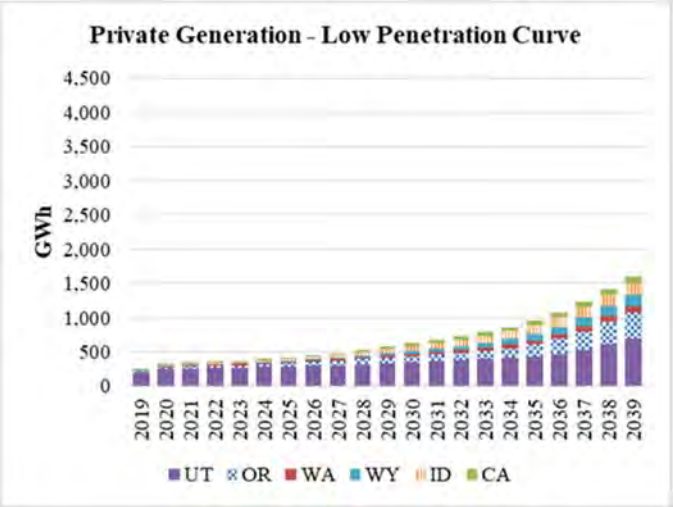
The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity: Low Private Generation (S-04)

Private Generation

Scenario private generation penetration by state and year are summarized in the following figure.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The high private generation sensitivity reflects more aggressive technology cost reduction assumptions, higher technology performance levels, and higher retail electricity rates, compared to base penetration levels incorporating annual reductions in technology costs. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

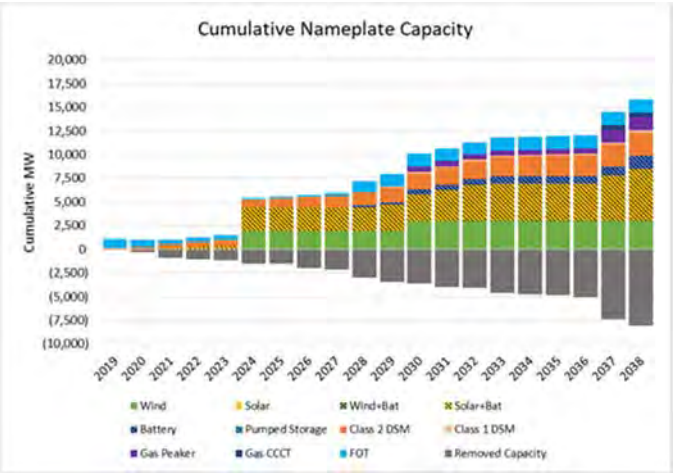
System Optimizer PVRR ($m) ***$21,371***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*

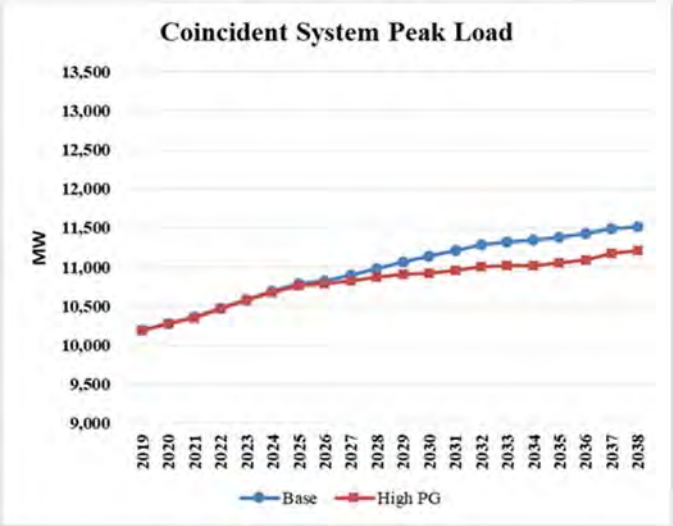
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.

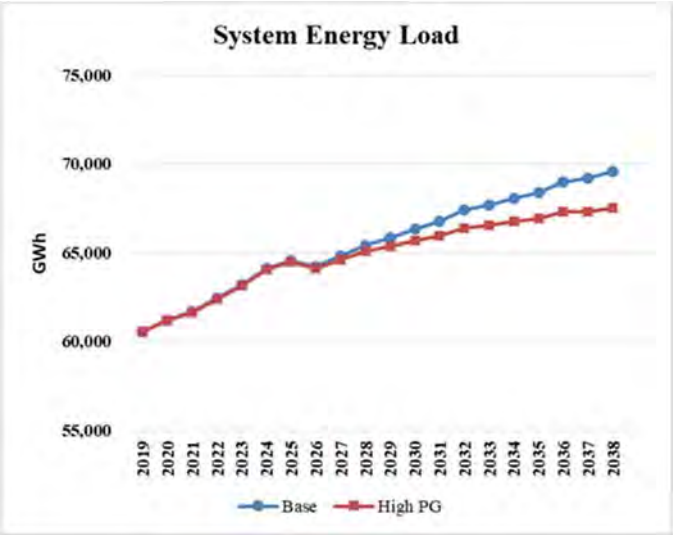


Load Forecast

The figure below shows the base system coincident peak load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



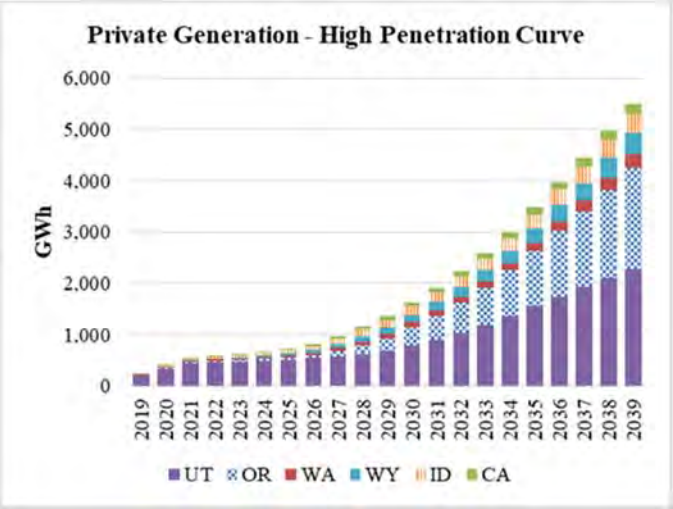
The figure below shows the base energy load forecast applicable to this case before accounting for any potential contribution from DSM alongside Base Case forecast. Loads include private generation resources.



Sensitivity: High Private Generation (S-05)

Private Generation

Scenario private generation penetration by state and year are summarized in the following figure.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The Business Plan sensitivity 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 December 2018 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. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

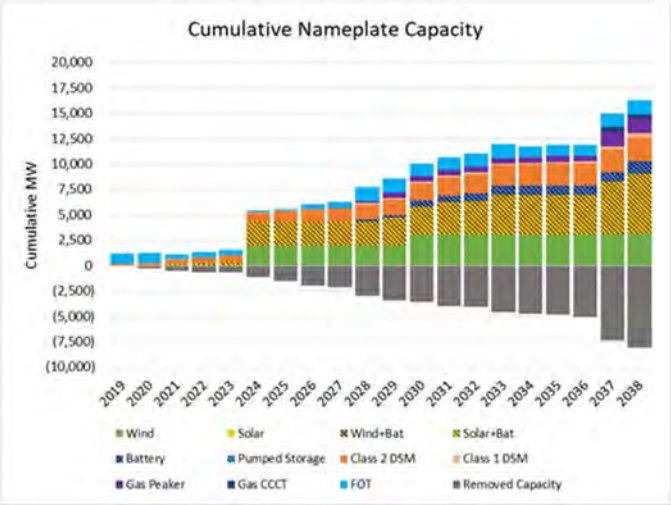
System Optimizer PVRR ($m) ***$21,695***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. OR/CA, Expansion	*2037*	*450*
Walla Walla- to - Yakima, Expansion	*2038*	*200*

Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The No Customer Preference sensitivity reflects no renewable resources specifically assigned to customer preference, compared to base renewable resource proxy options. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

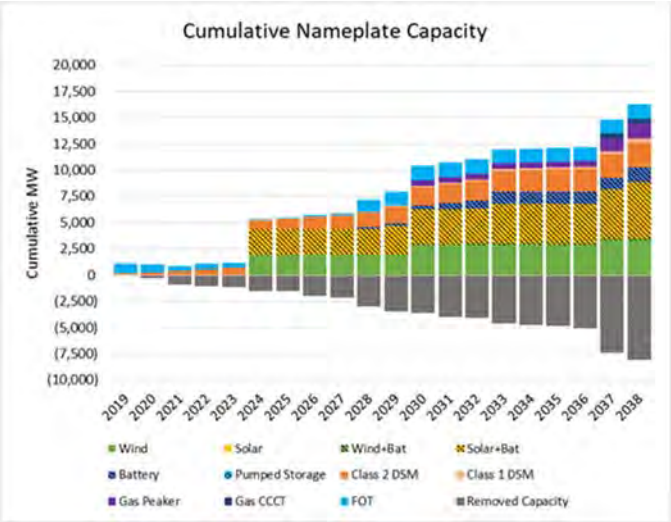
System Optimizer PVRR ($m) ***$21,609***

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. Oregon/California	*2037*	*450*

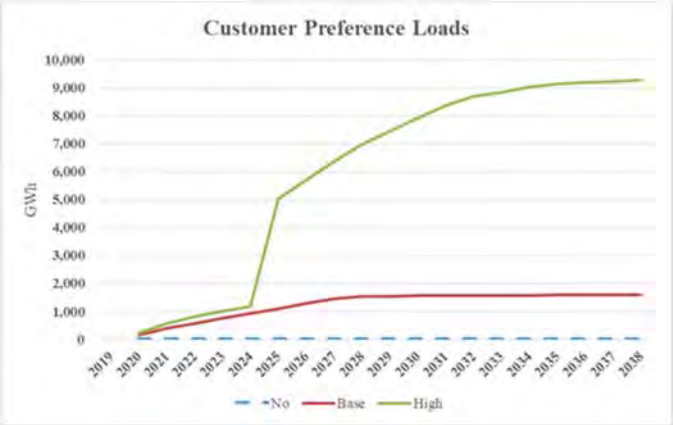
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Customer Preference

The figure below shows the difference between no, base and high Customer Preference Load scenarios for renewable resources.



Sensitivity Fact Sheets

CASE ASSUMPTIONS

Description

The High Customer Preference sensitivity reflects higher levels of renewable resource options assigned to customer preference, compared to base renewable resource proxy options. This sensitivity is a variant of the preferred portfolio, P-45CNW.

PORTFOLIO SUMMARY

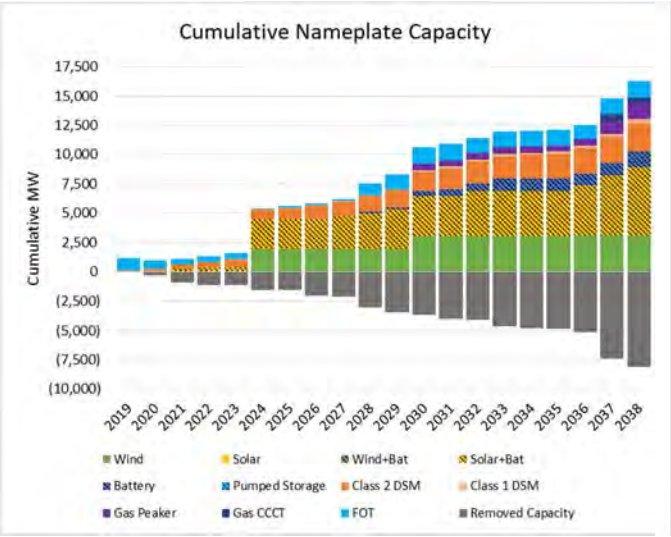
System Optimizer PVRR ($m) ***$21,636***

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Aeolus Wyoming – to - Utah S	*2024*	*1,700*
Goshen – to – Utah N	*2030*	*800*
Yakima- to – S. OR/CA, Expansion	*2036*	*450*

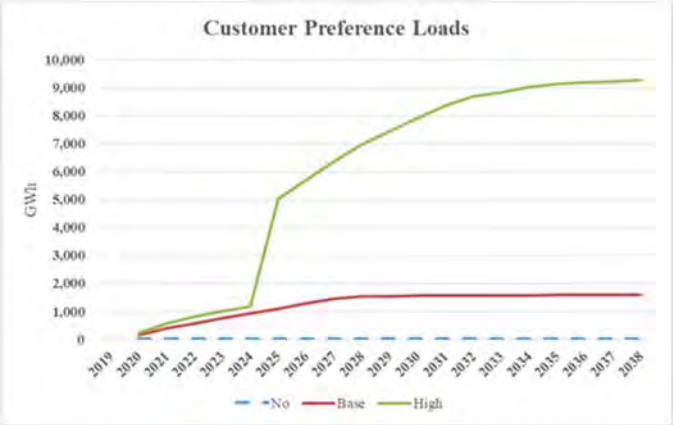
Resource Portfolio

Cumulative changes to the resource portfolio (new resource additions to address load service and reliability requirements and resource retirements), represented as cumulative nameplate capacity, are summarized in the figure below.



Customer Preference

The figure below shows the difference between no, base and high Customer Preference Load scenarios for renewable resources.



APPENDIX N –CAPACITY CONTRIBUTION STUDY

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. 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 coincident peak load obligation inclusive of a planning reserve margin throughout a 20-year planning horizon. Consequently, planning for the coincident peak drives the amount and timing of new resources, while resource cost and performance metrics among a wide range of different resource alternatives drive the types of resources that can be chosen to minimize portfolio costs and risks.

In the 2017 IRP, PacifiCorp calculated peak 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.

At the outset of the 2019 IRP, PacifiCorp calculated updated peak capacity contribution values for an expanded range of resources in addition to wind and solar, including:

- Energy storage, such as batteries and pumped storage,
- Demand response programs,
- Energy efficiency measures,
- Combined wind and battery resources,
- Combined solar and battery resources,
- Natural gas resources.

To better account for the specific characteristics of the expanded range of resources considered, the initial capacity contribution analysis was enhanced from that used in the 2017 IRP to account for the following:

- Distinct capacity contribution values for the summer and winter peaks;
- More granular analysis of LOLP event data to determine capacity contribution values for duration-limited resources such as energy storage and interruptible load programs;
- The impact of peak-producing temperatures on the maximum output of natural gas plants;
- Declining capacity contributions from wind and solar as penetration increases.

[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

The first three enhancements reflect the CF Method at a more granular level than was considered previously. The final modification uses much of the same inputs and calculations as the CF Method, but examines how reliability varies as a function of changes in the portfolio of resources using a more data-intensive analysis that is comparable to the equivalent conventional power method (ECP Method) described in the NREL Report. In all cases, capacity contribution values reflect the expected availability of resources when the risk of loss of load events is highest.

Both the CF Method and ECP Method rely on loss of load event data associated with PacifiCorp's loads and portfolio of resources. As such, selecting an appropriate portfolio as the basis of this data is important. For the 2019 IRP, the LOLP data used in the initial CF Method is derived from the same portfolio analysis used to select a planning reserve margin, as discussed in Volume II, Appendix I (Planning Reserve Margin Study). Specifically, the LOLP data starts with the 2030 test year results. Because there are so few events in the winter in this data, their distribution appears to be driven by random outage events more than the composition of PacifiCorp's portfolio. To produce a more accurate winter LOLP profile, PacifiCorp replaced the winter events in the 2030 data with the distribution of winter events in the 2036 studies and prorated the results such that the level of outages in the winter season was unchanged.

The ECP Method analysis demonstrates that incremental additions of solar resources have a declining capacity contribution, and that incremental additions of wind resources have a declining capacity contribution. However, these effects do not occur in isolation. For instance, to the extent the additional solar generation is reducing loss of load events during times when wind is low, the remaining loss of load events may occur during times when wind generation is high, resulting in a higher capacity contribution for wind. The portfolio impacts are highest for resources whose output varies across the day and by season, including wind and solar as well as energy efficiency. Portfolio impacts are also relevant to energy limited resources, including energy storage and demand response programs. At the extreme, a portfolio with only energy storage resources has no capacity, since those resources would be unable to charge. In general, adding more energy resources (e.g. wind, solar, thermal, or energy efficiency) will increase the capacity contribution of a given penetration of energy storage resources.

While these portfolio impacts are important, it is not feasible to calculate capacity contribution values for all resources in all possible portfolio combinations. Capacity contribution values are intended to identify a resource's ability to avoid loss of load events, but this is just a preliminary step in the creation of a reliable portfolio. With this outcome in mind, PacifiCorp evaluated the reliability of every portfolio and ensured that the combination of resources in every portfolio achieved a targeted level of reliability.

Although every portfolio is reliable, as a result of portfolio effects and reliability adjustments the capacity contributions attributable to various resource types is uncertain. To help shed light on this, PacifiCorp conducted an additional CF Method analysis based on a 2030 test year and the P-45CP portfolio.[2] The P-45CP portfolio has significant differences from the portfolio used in the initial CF Method results, including additional coal retirements and significantly more wind, solar, and energy storage resources. This final CF Method analysis provides a reasonable capacity contribution value so long as the changes relative to the preferred portfolio are small, since in

[2] The study for the CF Method analysis is lengthy, and there was not time to repeat it based on the final preferred portfolio, which has relatively slight differences. This additional CF Method analysis was not a factor in final portfolio selection.

effect, the CF Method calculates the marginal capacity contribution of a one megawatt resource addition. Note, this is not the same as the average capacity contribution of each megawatt of that resource type already included in the portfolio.

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 for a wind or solar resource to produce a weighted average 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 500-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Planning and Risk (PaR) model to simulate the dispatch of PacifiCorp's system for the

sample year.[3] This PaR study is based on PacifiCorp's 2019 IRP planning reserve margin study using a 13 percent target planning reserve margin level and the loss of load event data reflect PacifiCorp's participation in the Northwest Power Pool (NWPP) reserve sharing agreement, which allows a participant to receive energy from other participants within the first hour of a contingency event. The LOLP for each hour in the year is calculated by counting the number of iterations in which system load could not be met with available resources and dividing by 500 (the total number of iterations). For example, if in hour 19 on December 22nd there are three iterations with Energy Not Served (ENS) out of a total of 500 iterations, then the LOLP for that hour would be 0.6 percent.[4]

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.[5] The weighting factor for hour 19 on December 22nd would be 1.0417 percent.[6] 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.[7]

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 ENS hours out of 500 iterations. If all six ENS hours are in different iterations, a 1-hour energy storage resource could cover all six hours. However, if the six ENS 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 ENS hours.

ECP Methodology

The ECP Method identifies how much of a conventional resource can be removed when the resource being evaluated (typically a renewable resource) is added, while maintaining the same system reliability level. Unlike the CF Method, which uses the reliability results from a single study, the ECP Method requires at least two studies. While the CF Method can produce an estimate for any resource profile and represents a single megawatt of resource additions, the ECP Method

[3] Initial CF method results were based on a composite sample year, containing ENS data from a 2030 study period for June through September, and data from a 2036 study period for October through May. These time periods correspond with the periods used to determine summer and winter capacity contribution inputs, respectively.
[4] 0.6 percent = 3 / 500.
[5] 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.
[6] 1.0417 percent = 0.6 percent / 58 percent, or simply 1.0417 percent = 3 / 288.
[7] 0.4271 percent = 1.0417 percent x 41.0 percent.

produces an estimate for a specific resource profile and a specific megawatt quantity. Just like the CF Method, the ECP Method is dependent on the composition of the starting portfolio. While the ECP Method distills a capacity contribution down to a single value, the studies can also be used with the CF Method to differentiate between periods and resource profiles.

At the outset of the 2019 IRP, PacifiCorp used the ECP method to evaluate wind and solar capacity contributions in four portfolios with varying wind and solar penetrations. The results of these studies were used to estimate the capacity contribution of the wind and solar resources in PacifiCorp's initial portfolio, as well as to estimate the capacity contributions of higher penetrations of wind and solar capacity.

Table N.1 – ECP Method Capacity Contribution Values for Wind and Solar

Study	Nameplate Capacity (MW)	
	Wind	Solar
No wind or solar	0	0
No wind	0	2,218
No solar	3,722	0
Initial Portfolio	3,722	2,218
Capacity Contribution of Initial Portfolio		
MW	852	955
%	23%	43%
Capacity Contribution of Incremental Resources		
+1000 MW	15%	15%
+2000 MW	12%	2%
+3000 MW	6%	0%
+4000 MW	1%	0%

This ECP analysis reflects system-wide results based on the characteristics of existing assets, while capacity contribution is inherently related to the characteristics of specific resources. For instance, the latest wind and solar technology may produce higher capacity factors and higher capacity contributions on a per megawatt basis. To account for this, the ECP-based contribution values are not applied directly to the future resources. Instead, the CF Method is applied to individual resources and the results are de-rated by a uniform percentage as successive blocks are reached. To help limit the modeling complexity, two blocks of capacity contribution value for wind and solar were modeled for portfolio selection. The "high" capacity contribution block allowed for up to 2,000 megawatt (MW) of new wind capacity and 1,000 MW of new solar capacity (roughly a 50 percent increase from the initial portfolio levels). Any additional wind and solar capacity beyond the first block was assigned a "low" capacity contribution value, calculated based on an additional 2,000 MW of new wind capacity and 1,000 MW of new solar capacity.

Natural Gas Resources

As ambient temperature rises, the maximum output from many natural gas resources declines. In previous IRPs, the maximum output of natural gas plants was set on a monthly basis, based on average ambient conditions at the plant site for each month. In the development of capacity contribution values for the 2019 IRP, PacifiCorp identified a mismatch between the temperature

underlying the maximum output of natural gas units and the peak-producing temperatures on the hottest days in the summer which have the highest risk of loss of load events and drive capacity needs.

To better account for the capability of natural gas resources during peak conditions, the monthly maximum output of existing and potential natural gas units was modified during the summer months of July through September. During these months, the maximum output was calculated based on peak-producing temperatures, rather than average temperatures. This reduction in the maximum output of these resources directly impacts their summer capacity contribution, as well as their ability to provide generation and reserves.

Portfolio-Development Inputs

Table N.2 summarizes the capacity contribution inputs used in the portfolio-development process for stand-alone renewable and storage resources, developed using the methodologies described above.

Table N.2 – Initial Capacity Contribution Values for Wind, Solar, and Storage

	Capacity Factor (%)	Capacity Contribution (%)				
IRP:		**2017**	**2019**	**2019**	**2019**	**2019**
Summer/Winter:	**Annual**	**Annual**	**S**	**W**	**S**	**W**
Solar			**Block 1**		**Block 2**	
Idaho Falls, ID	28%	60%	27%	6%	4%	1%
Lakeview, OR	29%	65%	36%	7%	6%	1%
Milford, UT	32%	60%	20%	15%	3%	2%
Yakima, WA	25%	65%	35%	4%	5%	1%
Rock Springs, WY	30%	60%	22%	10%	3%	2%
Wind			**Block 1**		**Block 2**	
Pocatello, ID	37%	16%	20%	25%	4%	6%
Arlington, OR	37%	12%	37%	16%	9%	4%
Monticello, UT	29%	16%	14%	19%	3%	4%
Goldendale, WA	37%	12%	37%	15%	9%	3%
Medicine Bow, WY	44%	16%	17%	38%	4%	9%
Stand-alone Storage						
2 hour duration			67%	85%		
4 hour duration			91%	99%		
9 hour duration			100%	100%		

When wind and solar resources are combined with storage, the combined resource has a higher capacity contribution than the renewable resource on its own. For the purposes of the 2019 IRP, lithium-ion battery storage can be selected with either wind or solar resources. Combined storage is modeled with a maximum output equal to 25 percent of the renewable resource nameplate and

a four-hour storage duration. This combined resource is assumed to be limited to the renewable resource nameplate. Because of this limit to the combined output, the capacity contribution of a renewable and storage is not strictly additive. When renewable resource output exceeds 75 percent during individual hours with ENS under the CF Method, the addition of the battery can only increase the combined resource's capacity contribution to 100 percent for that hour. While such hours are relatively uncommon, the incremental capacity from the combined battery is reduced relative to a stand-alone battery. Table N.3 summarizes the capacity contribution inputs for renewable resources combined with storage.

Table N.3 – Initial Capacity Contribution Values for Wind and Solar Combined with Storage

	Capacity Factor (%)	Capacity Contribution (%)			
IRP:	**n/a**	**2019**	**2019**	**2019**	**2019**
Summer/Winter:	**Annual**	**S**	**W**	**S**	**W**
Solar & Storage		**Block 1**		**Block 2**	
Idaho Falls, ID	28%	48%	31%	26%	26%
Lakeview, OR	29%	58%	32%	27%	26%
Milford, UT	32%	42%	40%	25%	27%
Yakima, WA	25%	56%	29%	27%	25%
Rock Springs, WY	30%	44%	35%	26%	26%
Wind & Storage		**Block 1**		**Block 2**	
Pocatello, ID	37%	42%	47%	27%	28%
Arlington, OR	37%	55%	40%	26%	28%
Monticello, UT	29%	37%	44%	26%	29%
Goldendale, WA	37%	55%	39%	26%	28%
Medicine Bow, WY	44%	39%	57%	26%	28%

Reliability Assessment

The capacity contribution values described above are entered into the System Optimizer model, as one of a variety of parameters used to select an optimized portfolio of expansion resources. Once this portfolio is produced, PacifiCorp conducts a deterministic reliability assessment to assess the reliability of the resulting portfolio. Additional details on this process are provided in the Reliability Study Methodology section of Volume II, Appendix R (Coal Studies).

The deterministic reliability assessment identifies the quantity of incremental resources (if any) necessary to reliably meet load and all operating reserve requirements. If an incremental resource need is identified, the System Optimizer model is rerun with the ability to add or accelerate batteries, energy efficiency, gas peakers, and pumped hydro, relative to the pre-reliability portfolio. This process is analogous to the ECP Method described above in that it sets a uniform reliability target and adds conventional resources to portfolios that do not meet the target.

While the reliability assessment ensures each portfolio is reliable, it does not identify the individual contributions of the resources in that portfolio. For details on the effective capacity provided by the company's existing portfolio and new resources in the preferred portfolio, please refer to

Volume I, Chapter 5 (Resource Needs Assessment). To develop the results in Chapter 5, PacifiCorp first calculated the final CF Method capacity contribution values described below for resources other than wind and solar. Since the portfolio as a whole is reliable, the remaining capacity up to the targeted level of reliability is attributable to wind and solar. This remaining capacity was allocated to each wind and solar resource based on the wind and solar penetration analysis and the final CF Method results.

Final CF Method Results

PacifiCorp conducted an additional CF Method analysis during the final portfolio selection process based on a 2030 test year and the P-45CP portfolio. The P-45CP portfolio has significant differences from the portfolio used in the initial CF Method results, including additional coal retirements and significantly more wind, solar, and energy storage resources. As a result of these portfolio changes, the CF Method results can vary from the initial CF Method results.

The final CF Method results described below provide a reasonable capacity contribution value so long as the changes relative to the preferred portfolio are small, since in effect, the CF Method calculates the marginal capacity contribution of a one megawatt resource addition. Note, this is not the same as the average capacity contribution of each megawatt of that resource type already included in the portfolio.

Table N.4 – Final CF Method Capacity Contribution Values for Wind, Solar, and Storage

	Capacity Factor (%)	Capacity Contribution (%)	
Summer/Winter:	**Annual**	**S**	**W**
Solar			
Idaho Falls, ID	28%	12%	13%
Lakeview, OR	29%	15%	14%
Milford, UT	32%	10%	23%
Yakima, WA	25%	12%	10%
Rock Springs, WY	30%	11%	19%
Wind			
Pocatello, ID	37%	19%	27%
Arlington, OR	37%	57%	21%
Monticello, UT	29%	18%	22%
Goldendale, WA	37%	57%	21%
Medicine Bow, WY	44%	13%	35%
Stand-alone Storage			
2 hour duration		78%	89%
4 hour duration		94%	100%
9 hour duration		98%	100%

Table N.5 – Final CF Method Capacity Contribution Values for Wind and Solar Combined with Storage

	Capacity Factor (%)	Capacity Contribution (%)	
Summer/Winter:	**Annual**	**S**	**W**
Solar & Storage			
Idaho Falls, ID	28%	33%	37%
Lakeview, OR	29%	35%	39%
Milford, UT	32%	30%	48%
Yakima, WA	25%	33%	34%
Rock Springs, WY	30%	31%	43%
Wind & Storage			
Pocatello, ID	37%	38%	50%
Arlington, OR	37%	77%	44%
Monticello, UT	29%	37%	44%
Goldendale, WA	37%	76%	44%
Medicine Bow, WY	44%	32%	58%

The CF Method results are derived from a one year study period (2030) and ENS events are identified separately for every hour in that period. The details of the wind and solar resource modeling in the study period are important for interpreting the results. Where available, that study includes wind and solar shapes that also reflect specific volumes for each hour in the period, including 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 2017 hourly generation profiles of existing resources, adjusted to align with the expected annual output of each proxy resource. While the use of a single historical year can produce a reasonable forecast of wind and solar output, including a correlation between the two, additional work is needed in future IRPs to explore the variation and diversity of solar and wind output, and the relationships with load, particularly under peak load conditions.

The use of correlated hourly shapes produces variability across each month and a reasonable correlation between resources in close proximity. It also results 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 ENS 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 resources of the same type already in the portfolio, or if an appreciable quantity of resource additions are being contemplated.

APPENDIX O – PRIVATE GENERATION STUDY

Introduction

Navigant Consulting, Inc. prepared the Private Generation Long-Term Resource Assessment (2019-2038) for PacifiCorp. A key objective of this research is to assist PacifiCorp in developing private generation resource penetration forecasts to support its 2019 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.

Private Generation Long-Term Resource Assessment (2019-2038)

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August 15th, 2018

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August 15th, 2018

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EXECUTIVE SUMMARY

Navigant Consulting, Inc. (Navigant) prepared this Private Generation Long-term Resource Assessment on behalf of PacifiCorp. In this study private generation (PG) sources provide customer-sited (behind the meter) energy generation and are generally of relatively small size, generating less than the amount of energy used at a location. The purpose of this study is to support PacifiCorp's 2019 Integrated Resource Plan (IRP) by projecting the level of private generation resources PacifiCorp's customers might install over the next twenty years under base, low, and high penetration scenarios.

This study builds on Navigant's previous assessments, [1, 2] which supported PacifiCorp's 2015 and 2017 IRP, incorporating updated load forecasts, market data, technology cost and performance projections. Navigant evaluated five private generation technologies in detail in this report:

1. Photovoltaic (Solar) Systems
2. Small Scale Wind
3. Small Scale Hydro
4. Reciprocating Engines
5. Micro-turbines

Project sizes were determined based on average customer load across the commercial, irrigation, industrial and residential customer classes.

Private generation technical potential [3] and expected market penetration[4] for each technology was estimated for each major customer class in each state in PacifiCorp's service territory. Shown in Figure 1, PacifiCorp serves customers in California, Idaho, Oregon, Utah, Washington, and Wyoming.

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[1] Navigant, Distributed Generation Resource Assessment for Long-Term Planning Study, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Navigant_Distributed-Generation-Resource-Study_06-09-2014.pdf.

[2] Navigant, Private Generation Long-Term Resource Assessment (2017-2036), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_IRP_PG_Resource_Assessment_Final.pdf.

[3] Total resource potential factoring out resources that cannot be accessed due to non-economic reasons (i.e. land use restrictions, siting constraints and regulatory prohibitions), including those specific to each technology. Technical potential does not vary by scenario.

[4] Based on economic potential (technical potential that can be developed because it's not more expensive than competing options), estimates the timeline associated with the diffusion of the technology into the marketplace, considering the technology's relative economics, maturity, and development timeline.

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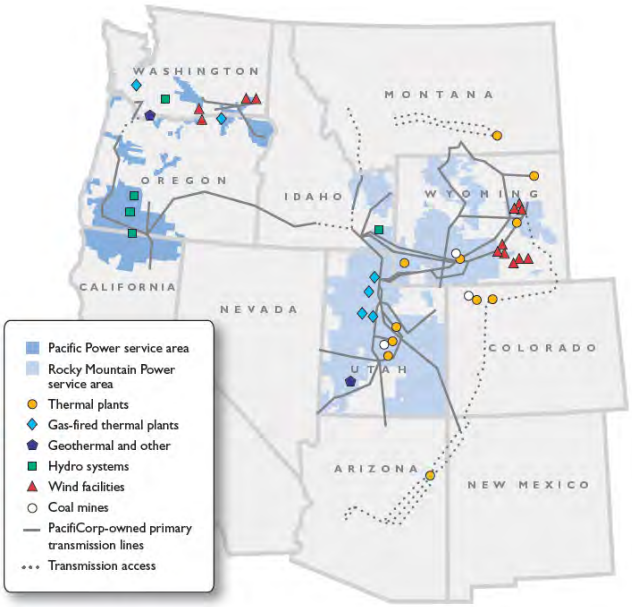
Figure 1 PacifiCorp Service Territory[5]



Key Findings

Using PacifiCorp-specific information on customer size and retail rates in each state and public data sources for technology costs and performance, Navigant conducted a payback analysis and used Fisher-Pry[6] diffusion curves to determine likely market penetration for PG technologies from 2019 to 2038. This analysis was performed for typical commercial, irrigation, industrial and residential PacifiCorp customers in each state.

In the base scenario, Navigant estimates approximately 1.3 GW AC of PG capacity will be installed in PacifiCorp's territory from 2019-2038.[7] As shown in Figure 2, the low and high scenarios project a cumulative installed capacity of 0.6 GW AC and 2.3 GW AC, respectively. The main differences between scenarios include variation in technology costs, system performance, and electricity rate escalation assumptions. These assumptions are provided in Table 8.

[5] http://www.pacificorp.com/content/dam/pacificorp/doc/About_Us/Company_Overview/Service_Area_Map.pdf.

[6] Fisher-Pry are researchers who studied the economics of "S-curves", which describe how quickly products penetrate the market. They codified their findings based on payback period, which measures how long it takes to recoup initial high first costs with energy savings over time.

[7] All capacity numbers across all five resources are projected in MW-AC. Figures throughout the report are all in MW-AC.

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Figure 2 Cumulative Market Penetration Results (MW AC), 2019 – 2038

Figure 3 indicates that Utah and Oregon will drive most PG installations over the next two decades, largely because these two states are PacifiCorp's largest markets in terms of customers and sales[8]. Reference APPENDIX A for detailed state-specific customer data. In both states, PG installations are also driven by local tax credits and incentives. As displayed in Figure 4, solar represents the highest expected market penetration across the five technologies examined, with residential solar development leading the way, followed by non-residential solar (commercial, industrial, and irrigation). The Results section of the report contains results by state and technology for the high, base, and low scenarios.

Figure 3 also compares this study's results to Navigant's 2016 report. The three main factors that impacted the adoption results from 2016 to 2018 include: electric rate, system cost and policy. Reference

Table 1 for a detailed comparison of the 2016 and 2018 adoption results. In the short-term, factors impacting adoption have a dampening effect on the market, yet more aggressive reduction in solar PV system costs longer-term, result in increased adoption over time. In 2036, the latest year in both studies, cumulative adoption in the base case is around 1000 MW in the 2018 study and around 1200 MW in the 2016 study.

[8] The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136 (Utah Docket 14-035-114)

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Figure 3 Cumulative Market Penetration Results by State (MW AC), 2019 – 2038, Base Case

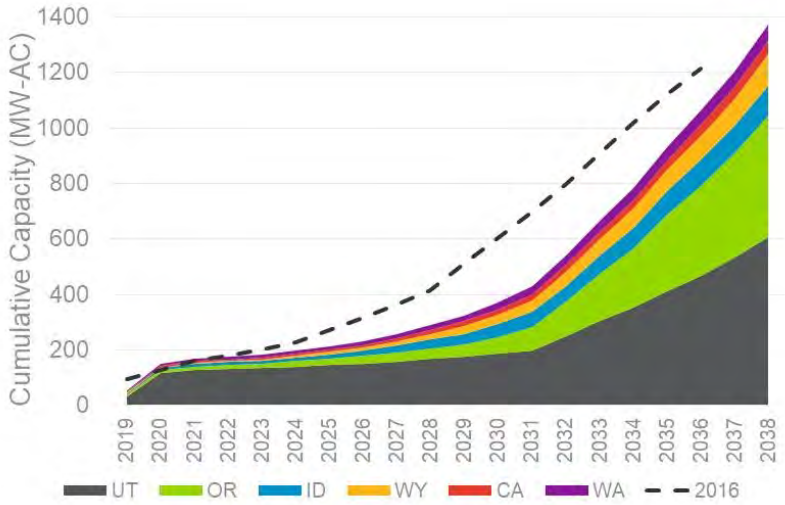
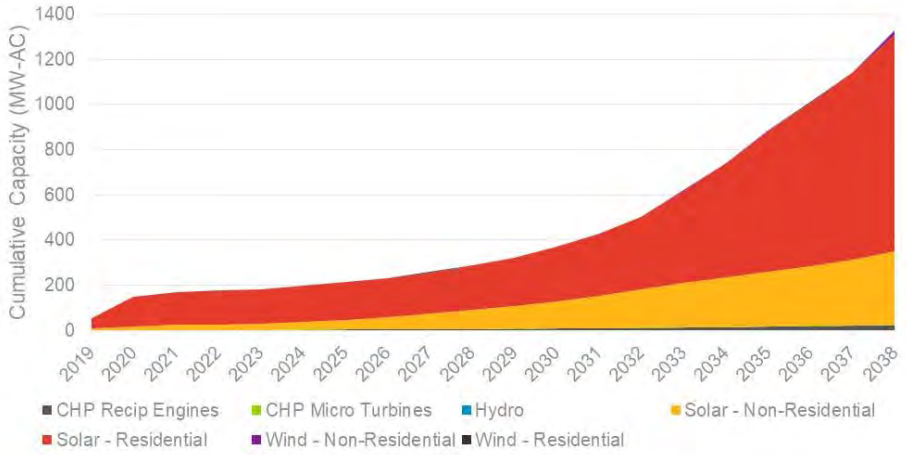


Figure 4 Cumulative Market Penetration Results by Technology (MW AC), 2019 – 2038, Base Case



The main factors that impacted the adoption results from 2016 to 2018 include: retail rates, system cost and policy. In general, the rates used in this study changed relative to the 2016 study as PacifiCorp's ability to calculate more accurate offset rates has increased. The technologies have not changed substantially since 2016, except for solar PV, where costs have continued to decline more rapidly than expected with ongoing declines expected in the future. Solar PV policies in key states (e.g., California, Oregon, Utah and Washington) have continued to fluctuate with an impact on expected near-term and long-term adoption. These changes between the 2016 and 2018 analysis are detailed in

Table 1.

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Table 1 Adoption Change from Electric Rate, System Cost and Policy Changes from 2016 to 2018

State	Estimated Adoption Change	Key Adoption Drivers
CA	**2036** – Market increased from 20 MW to 40 MW	• Rates: Increase (residential, commercial, industrial) • Solar PV Cost: Declines in the later years are more sustained • Policy: New mandatory solar for new building is included in the analysis
ID	**2036** – Market increased from 40 MW to 90 MW, primarily in the residential sector	• Rates: Increase (residential, commercial, industrial) • Solar PV Cost: Declines in the later years are more sustained • Policy: No change
OR	**2036** – Market remained relatively consistent, with adoption shifting to later years which seems reasonable given incentive declines offset by cost declines in future years	• Rates: Decrease (commercial, irrigation) • Solar PV Cost: Declines in the later years are more sustained • Policy: Incentive and cap reduced for residential and C&I; Residential Energy Tax Credit – sunset in 2017
UT	**2036** – Market decreased from 800 MW to 470 MW. Decline seems reasonable given residential incentive declines, and commercial rate declines	• Rates: Reduced net metering rates • Solar PV Cost: Declines in the later years are more sustained • Policy: Incentive for residential solar PV reduced from $2000 to $1600 in 2019 declining to $400 in 2024 and $0 beyond; NEM reduction to around 90% of full rates • The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136 (Utah Docket 14-035-114)
WA	**2036** – Market increased from 25 MW to 50 MW	• Rates: Small changes only • Solar PV Cost: Declines in the later years are more sustained • Policy: Solar and wind FIT reduced rate for an 8 year period
WY	**2036** – Market increased from 40 MW to 85 MW	• Rate: Small changes only • Solar PV Cost: Declines in the later years are more sustained • Policy: None

The impact of these factors, in aggregate, on PG adoption are shown in Figure 5. In the short-term, factors impacting adoption have a dampening effect on the market, yet more aggressive reduction in solar PV system costs longer-term, result in increased adoption over time. In 2036, the latest year in both studies, cumulative adoption in the base case is around 1,000 MW in the 2018 study and around 1,200 MW in the 2016 study.

Figure 5 Cumulative Market Penetration Results by Scenario (MW AC), 2018 and 2016 Study

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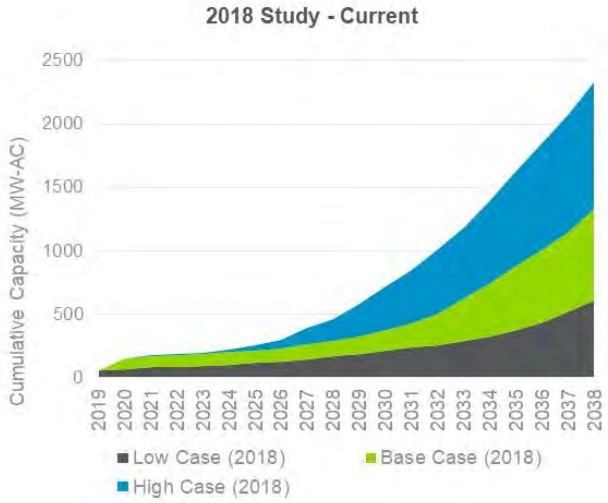

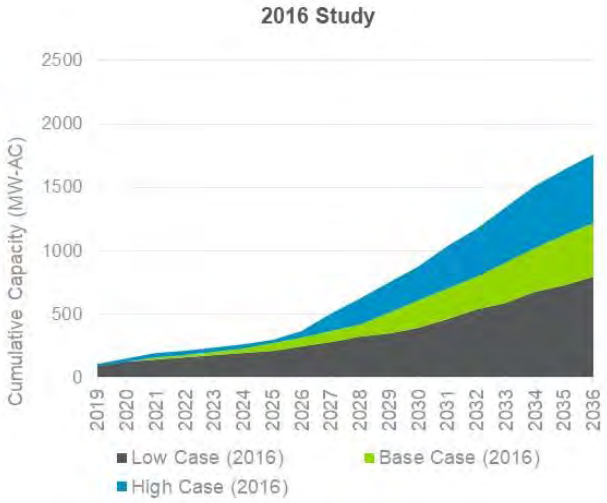

Report Organization

The report is organized as follows:

- Private Generation Market Penetration Methodology

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- Results
- APPENDIX A: Customer Data
- APPENDIX B: System Capacity Assumptions
- APPENDIX C: Detailed Numeric Results

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PRIVATE GENERATION MARKET PENETRATION METHODOLOGY

This section provides a high-level overview of the study methodology.

1.1 Methodology

In assessing the technical and market potential of each private generation (PG) resource and opportunity in PacifiCorp's service area, the study considered many key factors, including:

- Technology maturity, costs, and future cost projections
- Industry practices, current and expected
- Net metering policies
- Federal and state tax incentives
- Utility or third-party incentives
- O&M costs
- Historical performance, and expected performance projections
- Hourly PG Generation
- Consumer behavior and market penetration

1.2 Market Penetration Approach

The following five-step process was used to estimate the market penetration of PG resources in each scenario:

1. **Assess a Technology's Technical Potential:** Technical potential is the amount of a technology that can be physically installed without considering economics or other barriers to customer adoption. For example, technical potential assumes that photovoltaic systems are installed on all suitable residential roofs.
2. **Calculate Simple Payback Period for Each Year of Analysis:** From past work in projecting the penetration of new technologies, Navigant has found that Simple Payback Period is a key indicator of customer uptake. Navigant used all relevant federal, state, and utility incentives in its calculation of paybacks, incorporating their projected reduction and/or discontinuation over time, where appropriate.
3. **Project Ultimate Adoption Using Payback Acceptance Curves:** Payback Acceptance Curves estimate the percentage of a market that will ultimately adopt a technology, but do not factor in how long adoption will take.
4. **Project Market Penetration Using Market Penetration Curves:** Market penetration curves factor in market and technology characteristics, projecting the adoption timeline.
5. **Project Market Penetration under Different Scenarios.** In addition to the base case scenario, high and low case scenarios were created by varying cost, performance, and retail rate projections.[9]

[9] In the case of Utah, the Base and High cases for 2019 and 2020 solar PV installations were adjusted to reflect the capacity cap included within Schedule 136 (Utah Docket 14-035-114)

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These five steps are explained in detail in the following sections.

1.3 Assess Technical Potential

Each technology considered has its own characteristics and data sources that influence the technical potential assessment; the amount of a technology that can be physically installed within PacifiCorp's service territory without considering economics or other barriers to customer adoption. For this Navigant used the number of customers, system size, and access factors by technology. Navigant escalated technical potentials at the same rate PacifiCorp projects its sales will change over time. This also does not account for the electrical system's ability to integrate private generation.

1.4 Simple Payback

For each customer class (i.e., residential, commercial, irrigation and industrial), technology, and state, Navigant calculated the simple payback period using the following formula:

Simple Payback Period *= (Net Initial Costs) / (Net Annual Savings)*

Net Initial Costs *= Installed Cost – Federal Incentives – Capacity-Based Incentives*(1 – Tax Rate)*[10]

Net Annual Savings *= Annual Energy Bills Savings + (Performance Based Incentives – O&M Costs – Fuel Costs) * (1 – Tax Rate)*[10]

- *Federal tax credits can be taken against a system's full value if other (i.e. utility or state supplied) capacity-based or performance-based incentives are considered taxable.*
- *Navigant's Market Penetration model calculates first year simple payback assuming new installations for each year of analysis.*
- *For electric bills savings, Navigant conducted an 8,760-hourly analysis to consider actual rate schedules, actual output profiles, and demand charges. System performance assumptions are listed in Section 1.3 above. Solar performance and wind performance profiles were calculated for representative locations within each state based on the National Renewable Energy Laboratory (NREL) System Advisory Model (SAM). Building load profiles were provided by PacifiCorp and were scaled to match the average electricity usage for each customer class based on billing data.*

[10] Applies to all non-federal incentives regardless if it's coming from the state or another state-based entity.

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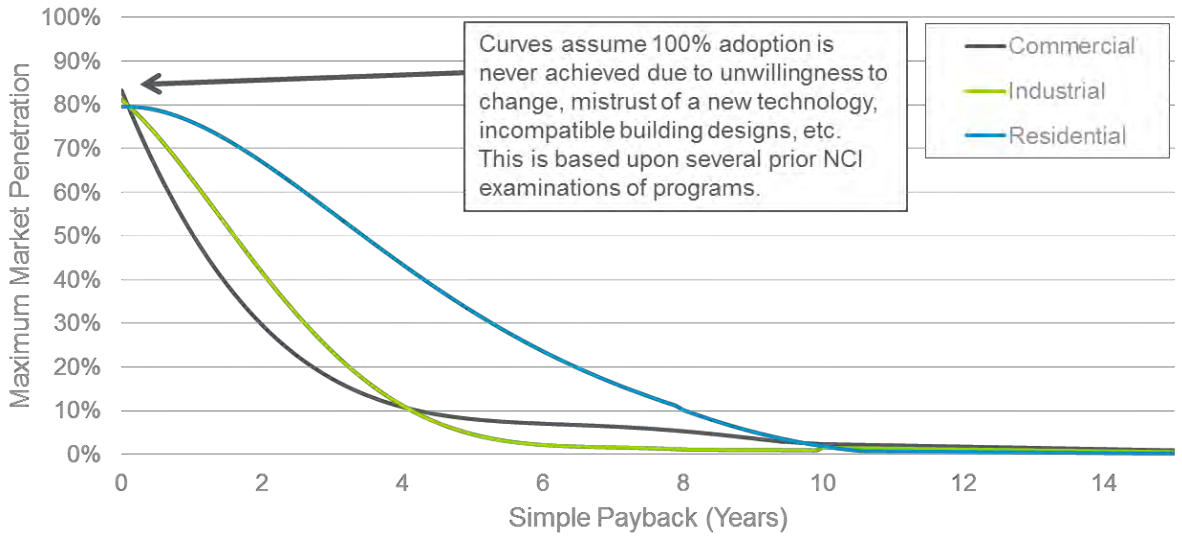
1.5 Payback Acceptance Curves

For private generation technologies, Navigant used the following payback acceptance curves to model market penetration of PG sources from the retail customer's perspective.

Figure 6 Payback Acceptance Curves



Source: Navigant Consulting based upon work for various utilities, federal government organizations, and state/local organizations. The curves were developed from customer surveys, mining of historical program data, and industry interviews.

These payback curves are based upon work for various utilities, federal government organizations, and state local organizations. They were developed from customer surveys, mining of historical program data, and industry interviews.[11] Given a calculated payback period, the curve predicts the level of maximum market penetration. For example, if the technical potential is 100 MW, the 3-year commercial payback predicts that 15% of this technical potential, or 15 MW, will ultimately be achieved over the long term.

1.6 Market Penetration Curves

To determine the future PG market penetration within PacifiCorp's territory, Navigant modeled the growth of PG technologies from 2019 thru 2038. The model is a Fisher-Pry based technology adoption model that calculates the market growth of PG technologies. It uses a lowest-cost approach to consumers to develop expected market growth curves based on maximum achievable market penetration and market saturation time, as defined below.[12]

- **Market Penetration** – The percentage of a market that purchases or adopts a specific product or technology. The Fisher-Pry model estimates the achievable market penetration based on characteristics of the technology and industry. Market penetration curves (sometimes called S-

[11] Payback acceptance curves are based on a broad set of data from across the United States and may not predict customer behavior in a specific market (e.g. Utah customers may install solar at different paybacks than indicated by the payback acceptance curves due to market specific reasons).

[12] Michelfelder and Morrin, "Overview of New Product Diffusion Sales Forecasting Models" provides a summary of product diffusion models, including Fisher-Pry. Available: law.unh.edu/assets/images/uploads/pages/ipmanagement-new-product-diffusion-sales-forecasting-models.pdf

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curves) are well established tools for estimating diffusion or penetration of technologies into the market. Navigant applies the market penetration curve to the payback acceptance curve shown in Figure 6 Payback Acceptance Curves.

- **Market Saturation Time** – The duration in years for a technology to increase market penetration from around 10% to 80%.

The Fisher-Pry model estimates market saturation time based on 12 different market input factors; those with the most substantial impact include:

- **Payback Period** – Years required for the cumulative cost savings to equal or surpass the incremental first cost of equipment.
- **Market Risk** – Risk associated with uncertainty and instability in the marketplace, which can be due to uncertainty regarding cost, industry viability, or even customer awareness, confidence, or brand reputation. An example of a high market risk environment is a jurisdiction lacking long-term, stable guarantees for incentives.
- **Technology Risk** – Measures how well-proven and the availability of the technology. For example, technologies that are completely new to the industry have a higher risk, whereas technologies that are only new to a specific market (or application) and have been proven elsewhere have lower risk.
- **Government Regulation** – Measure of government involvement in the market. A government-stated goal is an example of low government involvement, whereas a government mandated minimum efficiency requirement is an example of high involvement, having a significant impact on the market.

The model uses these factors to determine market growth instead of relying on individual assumptions about annual market growth for each technology or various supply and/or demand curves that may sometimes be used in market penetration modeling. With this approach, the model does not account for other more qualitative limiting market factors, such as the ability to train quality installers or manufacture equipment at a sufficient rate to meet the growth rates. Corporate sustainability, and other non-economic growth factors, are also not modeled.

The Fisher-Pry market growth curves have been developed and refined over time based on empirical adoption data for a wide range of technologies.[13] The model is an imitative model that uses equations developed from historical penetration rates of real products for over two decades. It has been validated in this industry via comparison to historical data for solar photovoltaics, a key focus of this study.

Navigant Consulting has used gathered market data on the adoption of technologies over the past 120 years and fit the data using Fisher-Pry curves. A key parameter when using market penetration curves is the assumed year of introduction. For the market penetration curves used in this study, Navigant assumed that the first-year introduction occurred when the simple payback period was less than 25 years (per the pay-back acceptance curves used, this is the highest pay-back period that has any adoption) or when state or local incentives were first introduced.
When the above payback period, market risk, technology risk, and government regulation factors above are analyzed, our general Fisher-Pry based method gives rise to the following market penetration curves used in this study:

[13] Fisher, J. C. and R. H. Pry, "A Simple Substitution Model of Technological Change", Technological Forecasting and Social Change, 3 (March 1971), 75-88.

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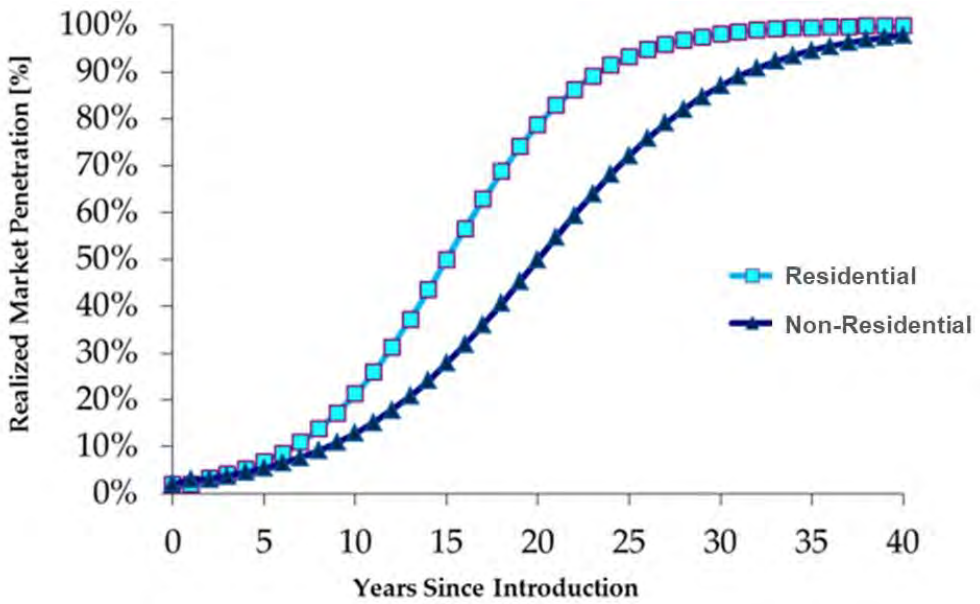
Figure 7 Market Penetration Curves [14]



Source: Navigant Consulting, November 2008 as taken from Fisher, J.C. and R.H. Pry, A Simple Substitution Model of Technological Change, *Technological Forecasting and Social Change*, Vol 3, Pages 75 – 99, 1971.

The model is designed to analyze the adoption of a single technology entering a market and assumes that the PG market penetration analyzed for each technology is additive because the underlying resources limiting installations (sun, wind, water, high thermal loads) are generally mutually exclusive, and because current levels of market penetration are relatively low (plenty of customers exist for each technology).

1.7 Key Assumptions

The following section details the key technology-specific and base, low and high scenario assumptions.

1.7.1 Technology Assumptions

The following tables summarize cost and performance assumptions for each technology. System size assumptions are provided in APPENDIX B.

1.7.1.1 Reciprocating Engines

A reciprocating engine uses one or more reciprocating pistons to convert pressure into rotating motion. In a combined heat and power (CHP) application, a small CHP source will burn a fuel (natural gas) to produce both electricity and heat. In many applications, the heat is transferred to water, and this hot water is then used to heat a building. In this study we assume the reciprocating engine generates electricity by using natural gas as the fuel.

[14] Realized market penetration is applied to the maximum market penetration (Figure **7**) for each technology, customer payback, and point in time. For example, a residential customer with a five-year payback would have a maximum market penetration of around 35 percent, as indicated by the residential payback acceptance curve (Figure 6). A technology that was introduced 10 years ago will have realized about 20 percent of its maximum market penetration (Figure **7**), having a market penetration of about seven percent of the technical potential.

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Navigant sized the system to meet the minimum customer load, assuming the reciprocating engine system would function to meet the customer's base load. Based on system size and product availability, reciprocating engines were assumed a reasonable technology for commercial and industrial customers. Assumptions on system capacity sizes in each state are detailed in APPENDIX B. Table 2 Reciprocating Engine Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

Table 2 Reciprocating Engine Assumptions[15]

PG Resource Costs	Units	2019 Baseline	Sources
Installed Cost – 100kW	$/kW	$2,970	EPA, Catalog of CHP Technologies, March 2015, pg. 2-15
Change in Annual Installed Cost	%	0.4%	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Variable O&M	$/MWh	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
Fuel Cost	$/MWh	PacifiCorp Gas Forecast	PacifiCorp Forecast
PG Performance Assumptions			
Electric Heat Rate (HHV)	Btu/kWh	12,637	EPA, Catalog of CHP Technologies, March 2015, pg. 2-10

1.7.1.2 Micro-turbines

Micro-turbines use natural gas to start a combustor, which drives a turbine. The turbine in turn drives an AC generator and compressor, and the waste heat is exhausted to the user. The device therefore produces electrical power from the generator, and waste heat to the user. In this study we assume the micro-turbine generates electricity by using natural gas as the fuel.

Navigant sized the system to meet the minimum customer load, assuming the reciprocating engine system would function to meet the customer's base load. Based on system size and product availability, reciprocating engines were assumed a reasonable technology for commercial and industrial customers. Assumptions on system capacity sizes in each state are detailed in APPENDIX B. Table 3 Micro-turbines Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

[15] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

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Table 3 Micro-turbines Assumptions[16]

PG Resource Costs	Units	2019 Baseline	Sources
Installed Cost – 30kW	$/kW	$2,685	EPA, Catalog of CHP Technologies, March 2015, pg. 5-7
Change in Annual Installed Cost	%	-0.3%	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 97
Variable O&M	$/MWh	$23	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 97
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
Fuel Cost	$/MWh	PacifiCorp Gas Forecast	PacifiCorp Forecast
PG Performance Assumptions			
Electric Heat Rate (HHV)	Btu/kWh	15,535	EPA, Catalog of CHP Technologies, March 2015, pg. 5-6

1.7.1.3 Small Hydro

Small hydro is the development of hydroelectric power on a scale serving a small community or industrial plant. The detailed national small hydro studies conducted by the Department of Energy (DOE) from 2004 to 2013,[17] formed the basis of Navigant's small hydro technical potential estimate. In the Pacific Northwest Basin, which covers WA, OR, ID, and WY, a detailed stream-by-stream analysis was performed in 2013, and DOE provided these data to Navigant directly. For these states, Navigant combined detailed GIS PacifiCorp service territory data with detailed GIS data on each stream / water source. Using this method, Navigant could sum the technical potentials of only those streams located in PacifiCorp's service territory. For the other two states, Utah and California, Navigant relied on an older 2006 national analysis, and multiplied the given state figures by the area served by PacifiCorp within that state. Table 4 provides the cost and performance assumptions used in the analysis and the source for each.

[16] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

[17] Navigant used the same methodology and sources as in the 2014 study.

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Table 4 Small Hydro Assumptions[18]

PG Resource Costs	Units	2019 Baseline	Sources
Installed Cost	$/kW	$4,000	Double average plant costs in "Quantifying the Value of Hydropower in the Electric Grid: Plant Cost Elements." Electric Power Research Institute, November 2011; this accounts for permitting/project costs
Change in Annual Installed Cost	%	0.00%	Mature technology, consistent with other mature technologies in the IRP.
Fixed O&M	$/kW-yr.	$52	Renewable Energy Technologies: Cost Analysis Series. "Hydropower." International Renewable Energy Agency, June 2012.
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
PG Performance Assumptions			
Capacity Factor	%	50% ±5%	Average capacity factor variance will be reflected in the low and high penetration scenarios.

1.7.1.4 Solar Photovoltaics

Solar photovoltaic (solar) systems convert sunlight to electricity. Navigant applied a 15% discount factor to account DC to AC conversion[19]. System size was then multiplied by the number of customers and the roof access factor. Assumptions on system capacity sizes in each state are detailed in APPENDIX B and access factors remained consistent with the 2014 and 2016 studies. Table 5 Solar Assumptions provides the cost and performance assumptions used in the analysis and the source for each.

[18] Note: No change from 2014 study.

[19] Navigant used a 15% discount factor to account for DC to AC conversion in PV systems. This value is consistent with industry standards and current system design.

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Table 5 Solar Assumptions

PG Resource Costs	Units	2019 Baseline	Sources
Installed Cost – Res	$/kW DC	UT: ~$2,500 Other: $2,750	Navigant Forecast validated by NREL, U.S. Photovoltaic Prices and Cost Breakdowns: Q1 2017 Benchmarks for Residential, Commercial and Utility-Scale Systems
Installed Cost – Non-Res	$/kW DC	All Markets: ~$1,900	
Average Change in Annual Installed Cost (2015-2034)	%	-2.8% (Res) -2.5% (Non-Res)	
Fixed O&M – Res	$/kW-yr.	$25	National Renewable Energy Laboratory, U.S. Residential Photovoltaic (PV) System Prices, Q4 2017 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices, Oct. 2014; National Renewable Energy Laboratory, Distributed Generation Renewable Energy Estimate of Costs, Accessed February 1, 2016
Fixed O&M – Non-Res	$/kW-yr.	$23	
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
DC to AC Derate Factor	#	0.85	Industry Standard

As shown in Figure 8 and Figure 9, the rapid decline in solar costs over the past decade has driven private solar adoption across the country for all customer classes. In the past, these cost declines were primarily due to reduction in the cost of equipment (e.g. panels, inverters and balance of system components) driven by economies of scale and improvements in efficiency. Solar costs are expected to continue to decline over the next decade as system efficiencies continue to increase, although these declines are expected to occur at a slower rate than what occurred in recent years. In the long term, Navigant expects price reductions to decline as the industry matures and efficiency gains become harder to achieve.

Navigant's national solar cost forecast includes a low, base and high forecast. For this project, Navigant developed a PacifiCorp forecast which is the average between the national base and high forecast. Navigant decided to use this forecast for California, Idaho, Oregon, Washington and Wyoming, as all those states currently have small solar markets in PacifiCorp territory, resulting in less competition and economies of scale to drive down local solar costs. For Utah, Navigant used the base cost forecast, as Utah has a larger and more mature private solar market.

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Figure 8. Non-Residential Solar System Costs, 2019-2038

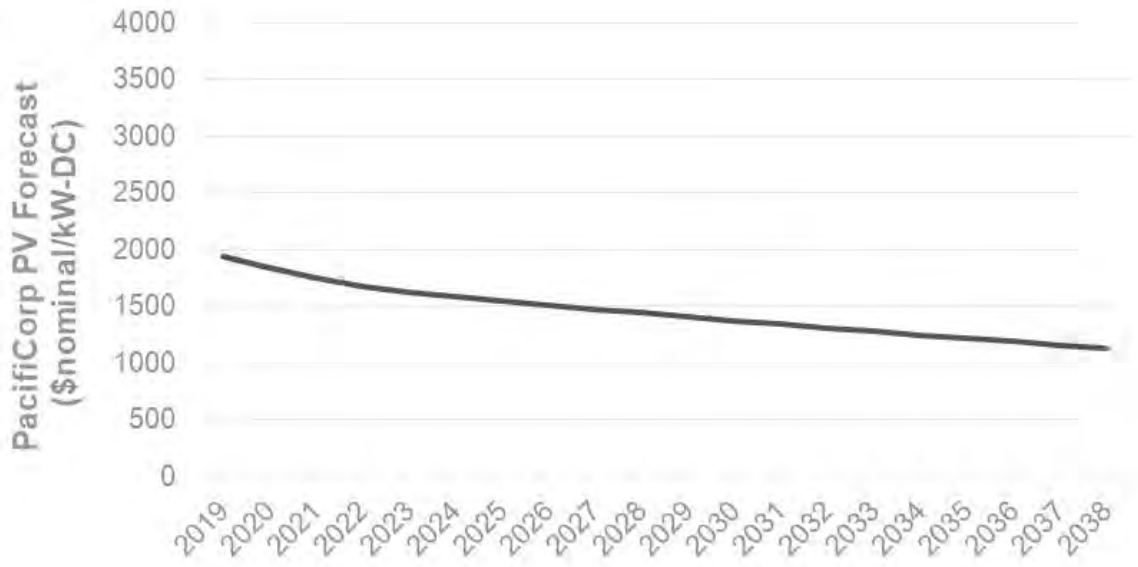
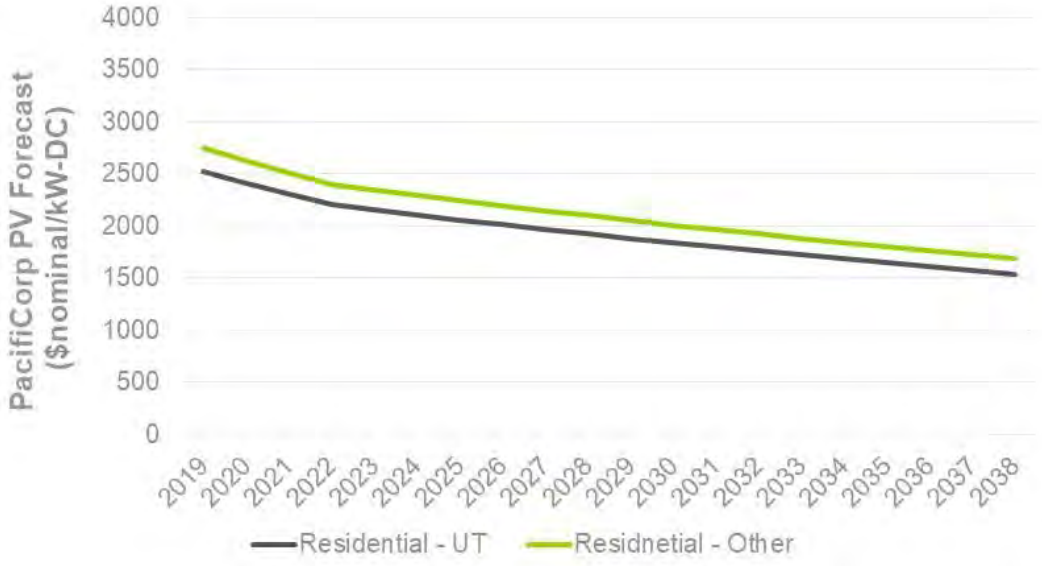


Figure 9 Residential Solar System Costs, 2019-2038



The solar capacity factors (Table 5) were calculated using NREL's System Advisory Model for each state territory.

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Table 6 Solar Capacity Factors[20]

Performance Assumptions		
		(kW-DC/kWh AC)
Capacity Factor	UT	16.3%
	WY	16.8%
	WA	14.0%
	CA	16.6%
	ID	16.0%
	OR	12.4%

1.7.1.5 Small Wind

Wind power is the use of air flow through wind turbines to mechanically power generators for electricity. Navigant sized the wind systems at 80% of customer load to reduce the chance that the wind system will produce more than the customer's electric load in a given year. System size was then multiplied by the number of customers and the access factor. The 2014 and 2016 study access factors were used for this study.

The following cost and performance assumptions were used in the analysis.

Table 7 Wind Assumptions

PG Resource Costs	Units	2019 Baseline	Sources
Installed Cost – Res (2.5-10kW)	$/kW	$7,200	Department of Energy, 2014 Distributed Wind Market Report, August 2015
Installed Cost – Com (11-100kW)	$/kW	$6,000	
Change in Annual Installed Cost	%	0.0%	Mature technology, consistent with other mature technologies in the IRP.
Fixed O&M	$/kW-yr.	$40	Department of Energy, 2014 Distributed Wind Market Report, August 2015
Change in Annual O&M Cost	%	-1.0%	Navigant Assumption
PG Performance Assumptions			
Capacity Factor	%	20% (2013) - 25% (2034)	Small scale wind hub heights are lower, with shorter turbine blades, relative to 30% capacity factor large scale turbines.

[20] Navigant used a DC to AC solar PV derate factor of 85%.

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1.7.2 Scenario Assumptions

Navigant used the market penetration model to analyze three scenarios, capturing the impact of major changes that could affect market penetration. For the low and high penetration cases, Navigant varied technology costs, system performance, and electricity rate assumptions.

Table 8 Scenario Variable Modifications

Scenarios				
Cases	Technology Costs	Performance	Electricity Rates	Other
Base Case	• See technology and cost section	• As modeled	• Increase at inflation rate, assumed at 2.0%	• Assumes the net metering cap is achieved. Solar PV adoption forecast was adjusted in 2019 and 2020 to reflect this. • Adoption in all other years is based on customer economics.
Low Attractiveness	• PV: Years 1-10: Same as Base Case • Years 11+: Rate of decline is 25% lower than base case • Other: Mature technologies. Same as base case	• PV: Same as Base Case • Other: 5% worse	• Increases at 1.6%, 0.4%/year lower than the Base Case	• Assumes adoptions in based on customer economics for all years.
High Attractiveness	• PV: Years 1-10: Same as Base Case • Years 11+: rate of decline is 50% higher than base case • Other: Mature technologies. Same as base case	• Reciprocating Engines: 0.5% better (mature) • Micro-turbines: 2% better • Hydro: 5% better (reflecting wide performance distribution uncertainty) • PV/Wind: 1% better (relatively mature)	• Increases at 2.4%, 0.4%/year higher than the Base Case	• Assumes the net metering cap is achieved. Solar PV adoption forecast was adjusted in 2019 and 2020 to reflect this. • Adoption in all other years is based on customer economics.

Technology cost reduction is the variable with the largest impact on market penetration over the next 20 years. Average technology performance assumptions are relatively constant across states and sites. Changes in electricity rates are modeled conservatively, reflecting the long-term stability of electricity rates in the United States. Navigant expects short-term volatility for all variables but when averaged over the 20-year IRP period, long-term trends show less variation.

1.7.3 Incentives

Federal and state incentives are a very important PG market penetration driver, as they can reduce a customer's payback period significantly.

1.7.3.1 Federal

The Federal Business Energy Investment Tax Credit (ITC) allows the owner of the system to claim a tax credit for a certain percentage of the installed PG system price.[21] The ITC, originally set to expire in 2016 for residential solar systems and reduce to 10% for commercial solar systems, was extended for solar PV systems in December 2015 through the end of 2021, with step downs occurring in 2020 through 2022. The table below details how the ITC applies to the technologies evaluated in this study, however, this schedule may change in the future.

[21] Business Energy Investment Tax Credit, http://energy.gov/savings/business-energy-investment-tax-credit-itc.

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Table 9 Federal Tax Incentives

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**10%**	**10%**	**10%**	**0%**	**0%**	**0%**
Micro Turbines	**10%**	**10%**	**10%**	**0%**	**0%**	**0%**
Small Hydro	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
PV - Com	**30%**	**26%**	**22%**	**10%**	**10%**	**10%**
PV - Res	**30%**	**26%**	**22%**	**0%**	**0%**	**0%**
Wind - Com	**12%**	**0%**	**0%**	**0%**	**0%**	**0%**
Wind - Res	**30%**	**26%**	**22%**	**22%**	**0%**	**0%**

1.7.3.2 State

State incentives drive the local market and are an important aspect promoting PG market penetration. Currently, all states evaluated have full retail rate net energy metering (NEM) in place for all customer classes considered in this analysis. The study assumes that NEM policy remains constant, although future uncertainty exists surrounding NEM policy. Longer-term uncertainty also exists regarding other state incentives. Idaho also has a local state residential personal tax deduction for solar and wind projects. Currently, state incentives do not exist in California[22] or Wyoming.

The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136[23]. The value of generated energy takes into consideration the reduced compensation for exported energy included in the tariff as well as the capacity cap (see section 1.8.4 for more detail).

The following tables detail the assumptions made regarding local state incentives.

[22] In 2007, California launched the California Solar Initiative, however, incentives no longer remain in most utility territories, http://csi-trigger.com/.

[23] Utah Docket 14-035-114

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Table 10 Oregon Incentives

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**
PV – Com ($/W)	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**	**$0.50-$0.20/W**
PV – Res ($/W)	**$0.55/W**	**$0.55/W**	**$0.55/W**	**$0.55/W**	**$0.55/W**	**$0.55/W**
Wind – Com ($/kWh)	**0**	**0**	**0**	**0**	**0**	**0**
Wind – Res ($)	**0**	**0**	**0**	**0**	**0**	**0**

* Energy Trust of Oregon Solar Incentive (capped at $1.5M/year for residential).

Table 11 Utah Incentives

Technology	2019	2020	2021	2022	2023	2023	>2024
Recip. Engines (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Micro Turbines (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Small Hydro (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
PV – Com (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
PV – Res ($)*	**$1,600**	**$1,600**	**$1,600**	**$1,200**	**$800**	**$400**	**$0**
Wind – Com (%)	**10**	**10**	**10**	**10**	**10**	**10**	**10**
Wind – Res ($)*	**$1,200**	**$800**	**$400**	**$0**	**$0**	**$0**	**$0**

*Renewable Energy Systems Tax Credit, Program Cap: Residential cap = $2,000; commercial systems <660kW, no limit

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Table 12 Washington Incentives

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**
PV – Com ($/kWh)*	**$0.04 (+$0.04)**	**$0.02 (+$0.03)**	**$0.02 (+$0.02)**	**0**	**0**	**0**
PV – Res ($/kWh)*	**$0.14 (+$0.04)**	**$0.12 (+$0.03)**	**$0.10 (+$0.02)**	**0**	**0**	**0**
Wind – Com ($/kWh)*	**$0.04 (+$0.04)**	**$0.02 (+$0.03)**	**$0.02 (+$0.02)**	**0**	**0**	**0**
Wind – Res ($/kWh)*	**$0.14 (+$0.04)**	**$0.12 (+$0.03)**	**$0.10 (+$0.02)**	**0**	**0**	**0**

* Feed-in Tariff: $/kWh for all kWh generated through mid-2020; annually capped at $5,000/year, http://programs.dsireusa.org/system/program/detail/5698

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Table 13 Idaho Incentives

Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**
PV - Com	**0**	**0**	**0**	**0**	**0**	**0**
PV – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**
Wind – Com	**0**	**0**	**0**	**0**	**0**	**0**
Wind – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**

* Residential Alternative Energy Income Tax Deduction: 40% in the first year and 20% for the next three years, http://programs.dsireusa.org/system/program/detail/137.

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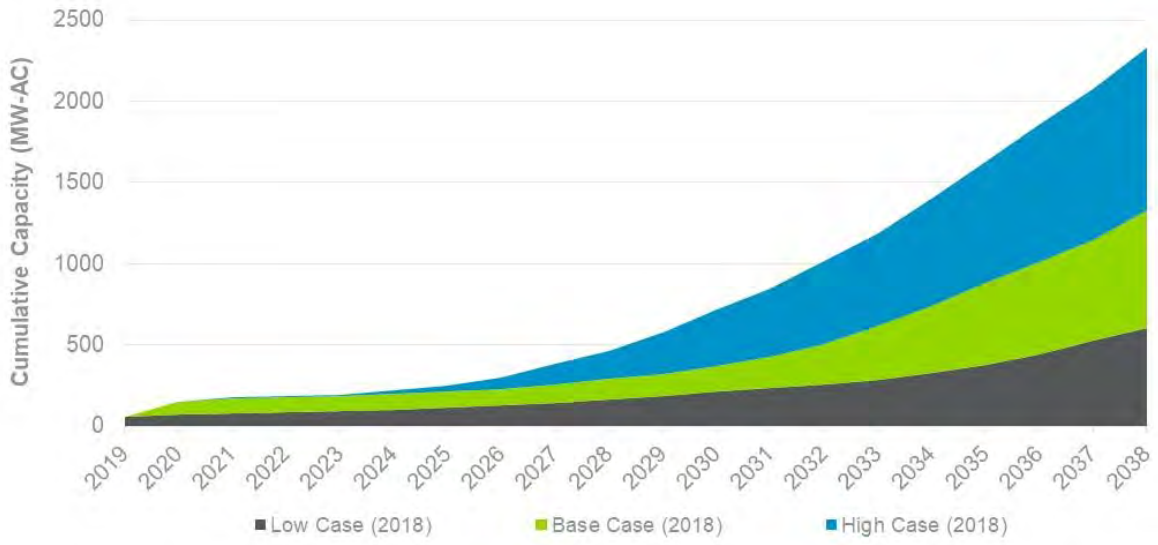
RESULTS

Navigant estimates approximately 1.3 GW of PG capacity will be installed in PacifiCorp's territory from 2019-2038 in the base case scenario. As shown in Figure 10, the low and high scenarios project a cumulative installed capacity of 0.60 GW and 2.3 GW by 2038, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions.

Figure 10. Cumulative Market Penetration Results (MW AC), 2019 – 2038



1.8 PacifiCorp Territories

The following sections report the results by state, providing high, base and low scenario installation projections. Results for each scenario are also broken out by technology. The solar sector exhibits the highest adoption across all states. Generally non-residential solar adoption is less sensitive to high and low scenario adjustments when compared to the residential sector. This is because the residential customer payback is more sensitive to scenario changes (e.g. technology costs, performance, electricity rates) when compared to non-residential sectors.

1.8.1 California

PacifiCorp's customers in northern California are projected to install about 48 MW of capacity over the next two decades in the base case, averaging about 2.4 MW, annually. California does not currently have any state incentives promoting the installation of PG and the ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations after 2020. The main driver of PG in California is its high electricity rates relative to other states. Over time, the increase in PG installation capacity is driven by escalating electricity rates (benchmarked to inflation) and declining technology costs. Both residential and non-residential solar installations are responsible for the majority of PG growth over the horizon of this study.

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While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 11. The 48 MW from the base case decreases by 35% to 31 MW in the low case and increases by 40% to 67 MW in the high case.

Figure 11. Cumulative Capacity Installations by Scenario (MW AC), California

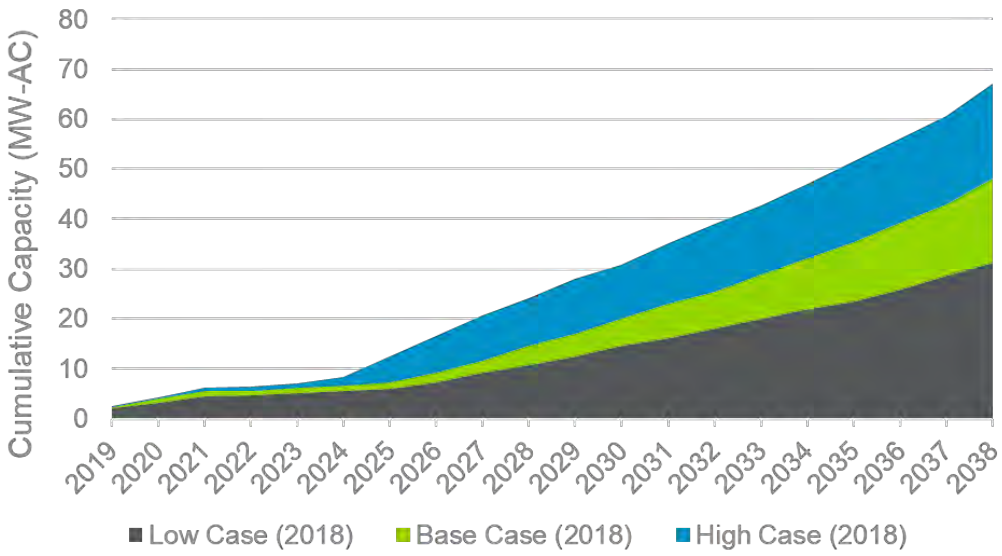

Figure 12. Cumulative Capacity Installations by Technology (MW AC), California Base Case

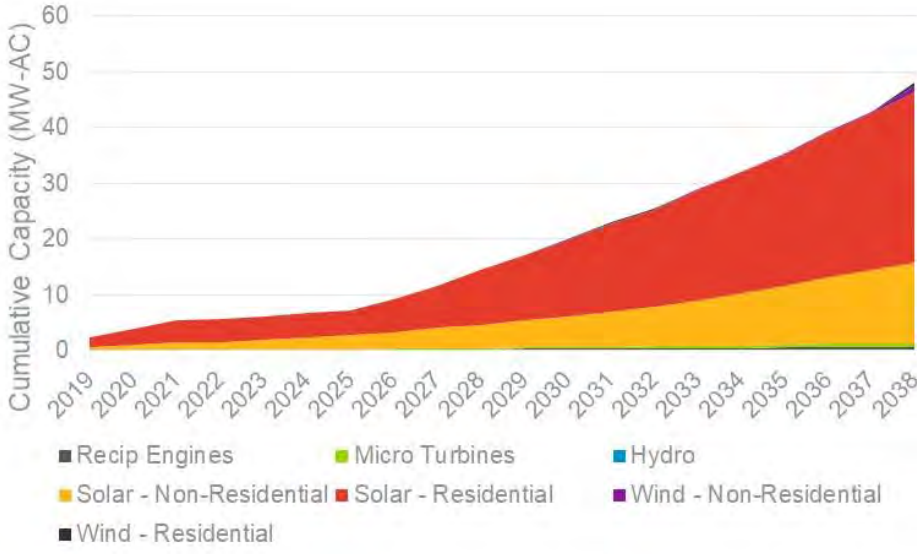

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Figure 13. Cumulative Capacity Installations by Technology (MW AC), California High Case

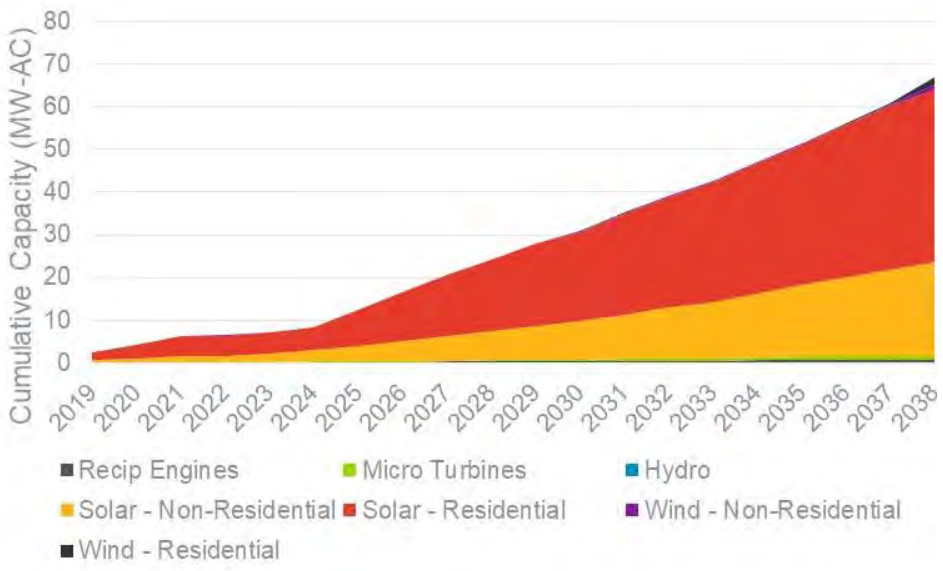
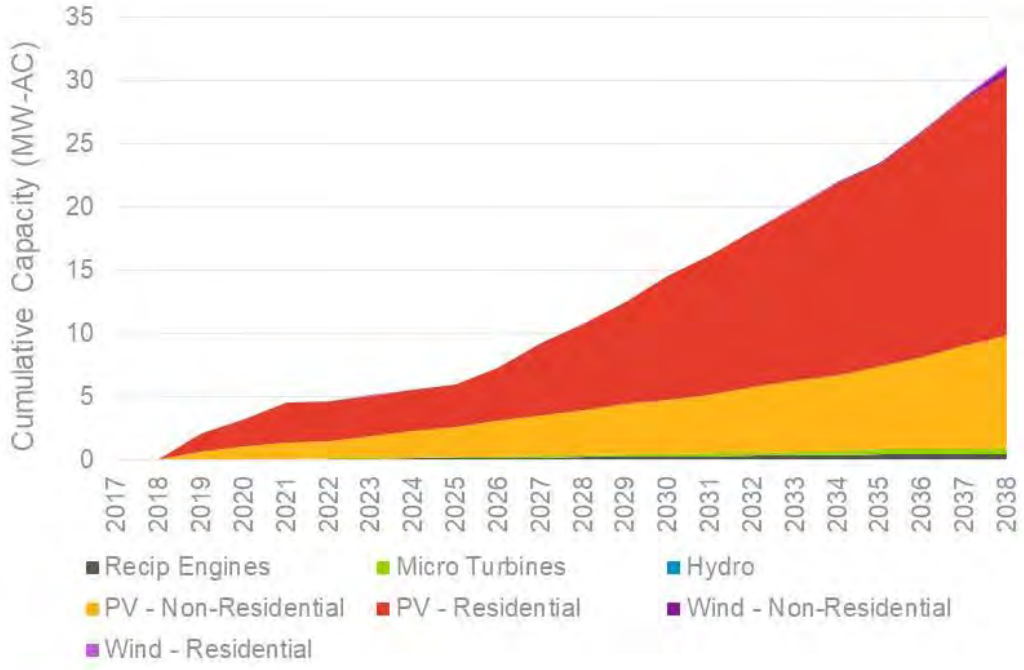


Figure 14. Cumulative Capacity Installations by Technology (MW AC), California Low Case



1.8.2 Idaho

PacifiCorp's Idaho customers are projected to install about 108 MW of capacity over the next two decades in the base case, averaging about 5.4 MW annually. Idaho currently has a Residential

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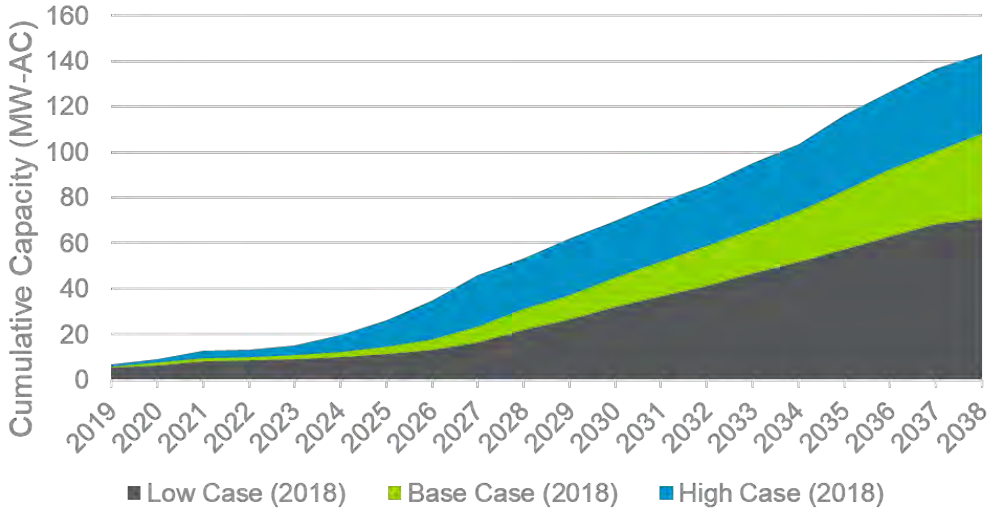
Alternative Energy Income Tax Deduction for residential solar and wind installations[24], although this incentive seems to have had minimal impact on the market, as non-residential solar installations are responsible for the majority of PG growth in the early years due to a combination of technical potential and escalating electric rates. The ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations in the short term and overtime the increase in PG installation capacity is driven by escalating electricity rates (benchmarked to inflation) and declining technology costs.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 15. The 108 MW from the base case decreases by 34% to 71 MW in the low case and increases by 32% to 143 MW in the high case.

Figure 15. Cumulative Capacity Installations by Scenario (MW AC), Idaho



[24] Residential Alternative Energy Income Tax Deduction: 40% in the first year and 20% for the next three years, http://programs.dsireusa.org/system/program/detail/137.

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Figure 16. Cumulative Capacity Installations by Technology (MW AC), Idaho Base Case

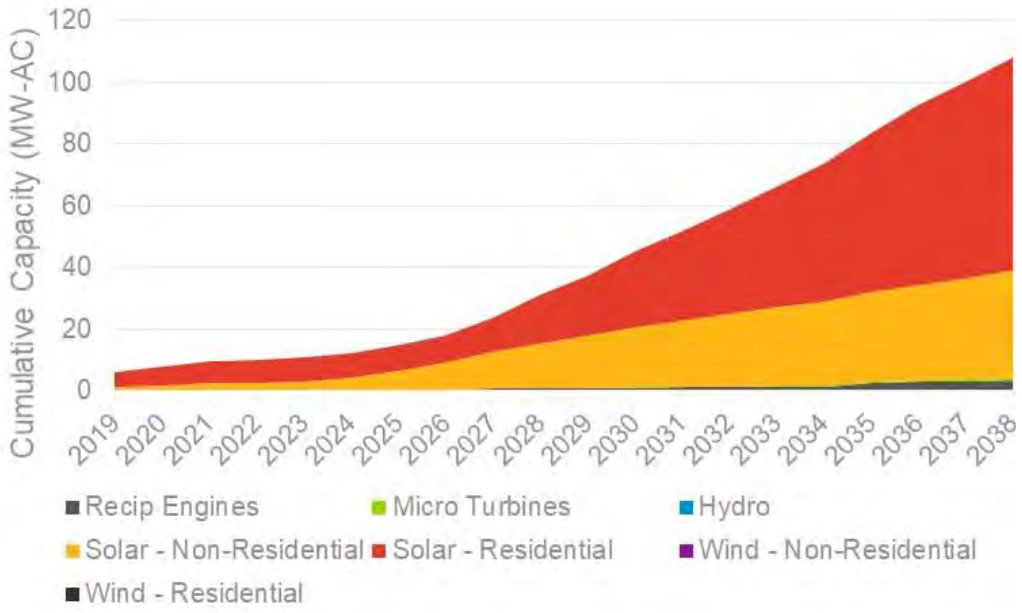

Figure 17. Cumulative Capacity Installations by Technology (MW AC), Idaho High Case

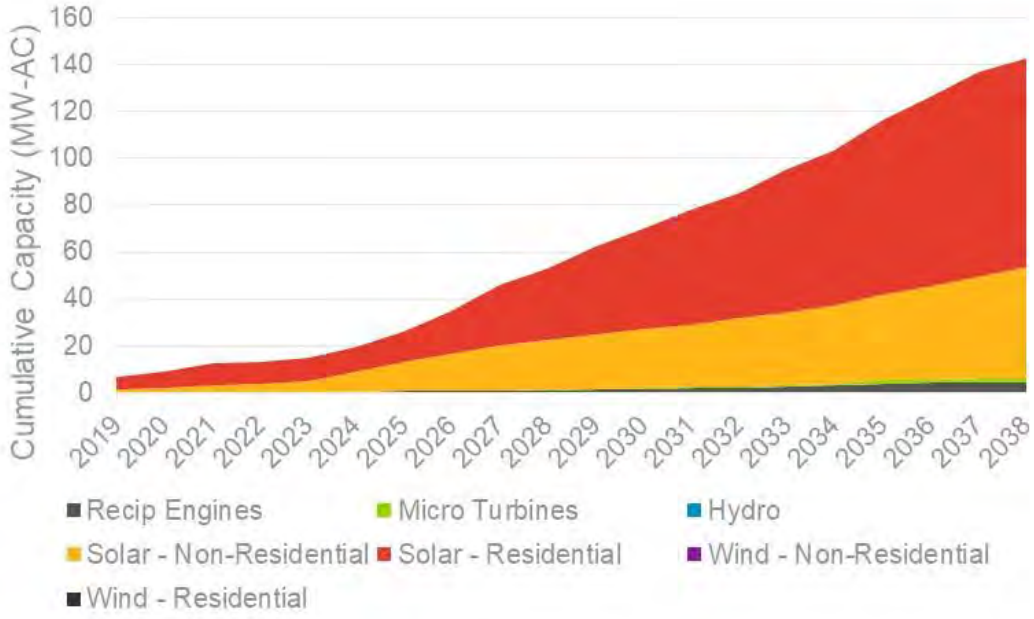

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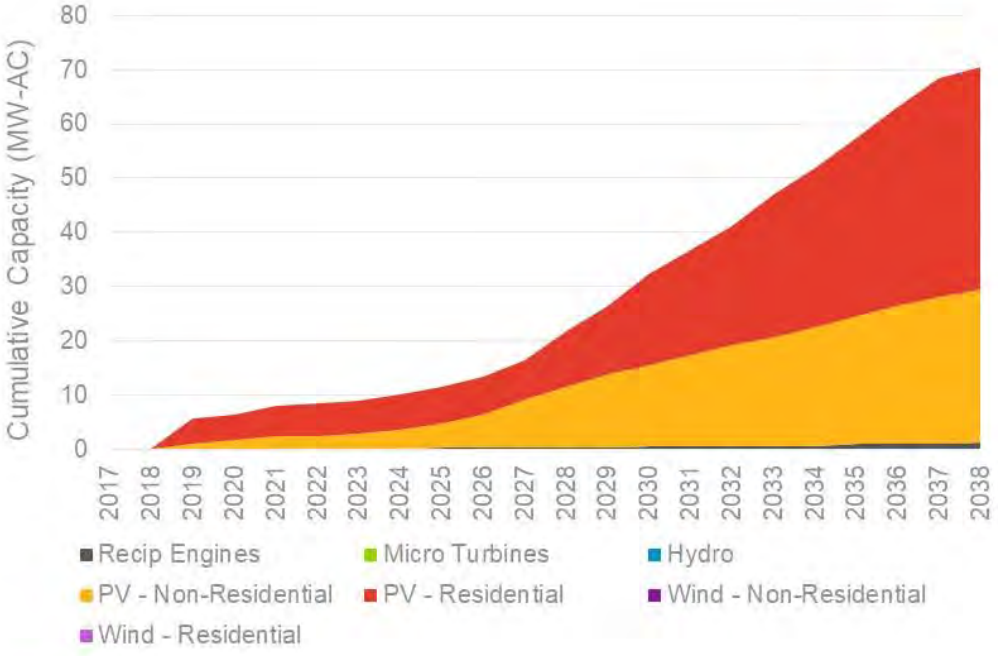
Figure 18. Cumulative Capacity Installations by Technology (MW AC), Idaho Low Case



1.8.3 Oregon

PacifiCorp's Oregon customers are projected to install about 435 MW of PG capacity over the next two decades in the base case, averaging about 21.75 MW annually. Solar is responsible for the majority of PG growth over the horizon of this study, with small growth from CHP reciprocating engines and non-residential wind. The stronger solar resource in Oregon relative to most of other states in PacifiCorp's territory and the Energy Trust of Oregon's Solar Incentive drive solar market adoption. The ratcheting down of the Federal ITC from 2020 to 2022 results in a relatively flat market in the short term but overtime the increase in solar capacity installation is driven by escalating electricity rates (benchmarked to inflation) and declining technology costs.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 19. The 435 MW from the base case decreases by 58% to 184 MW in the low case and increases by 123% to 968 MW in the high case.

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Figure 19. Cumulative Capacity Installations by Scenario (MW AC), Oregon

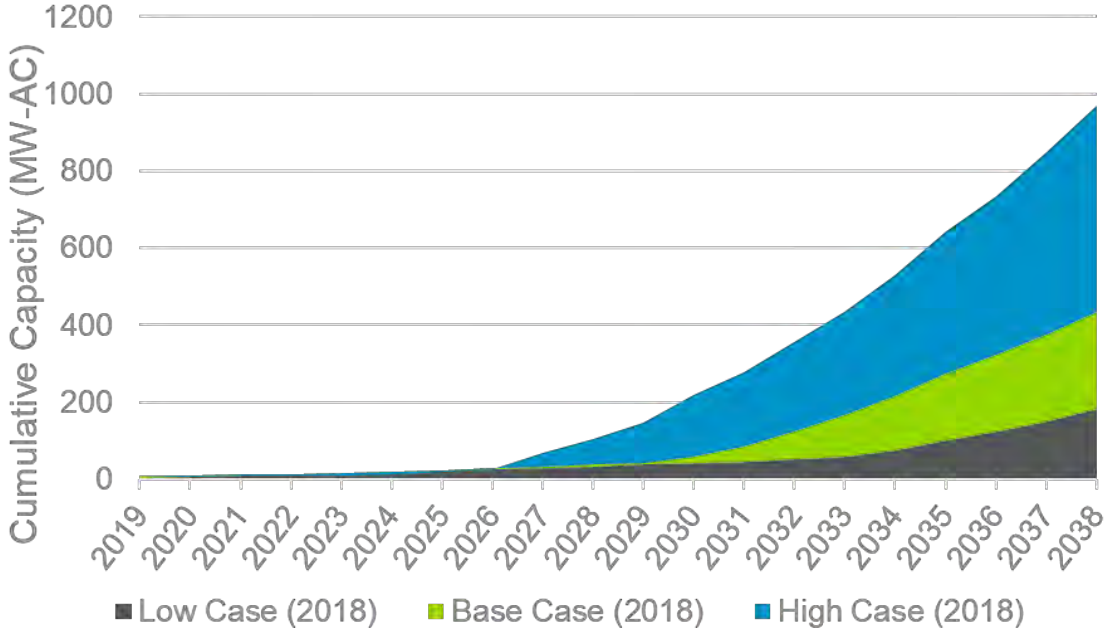

Figure 20. Cumulative Capacity Installations by Technology (MW AC), Oregon Base Case

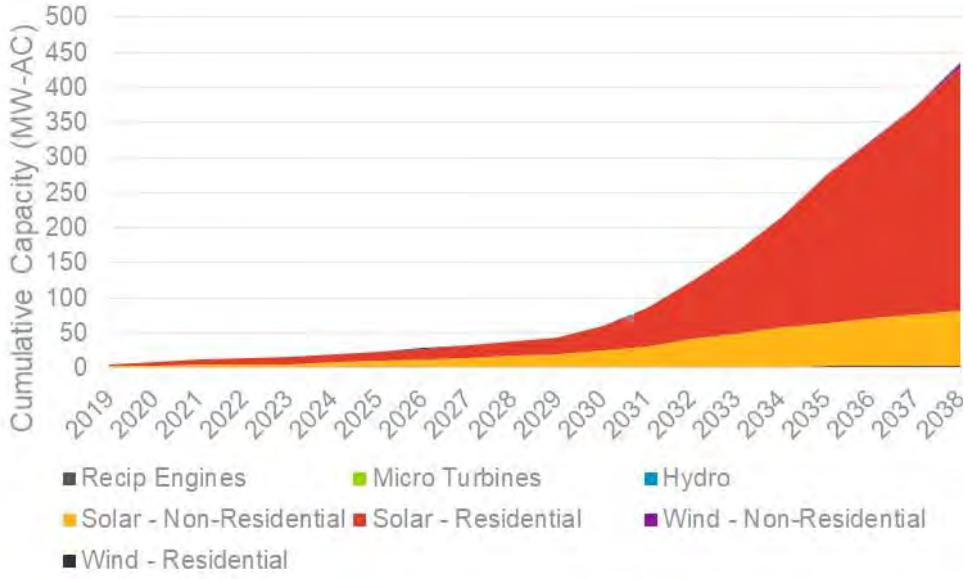

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Figure 21. Cumulative Capacity Installations by Technology (MW AC), Oregon High Case

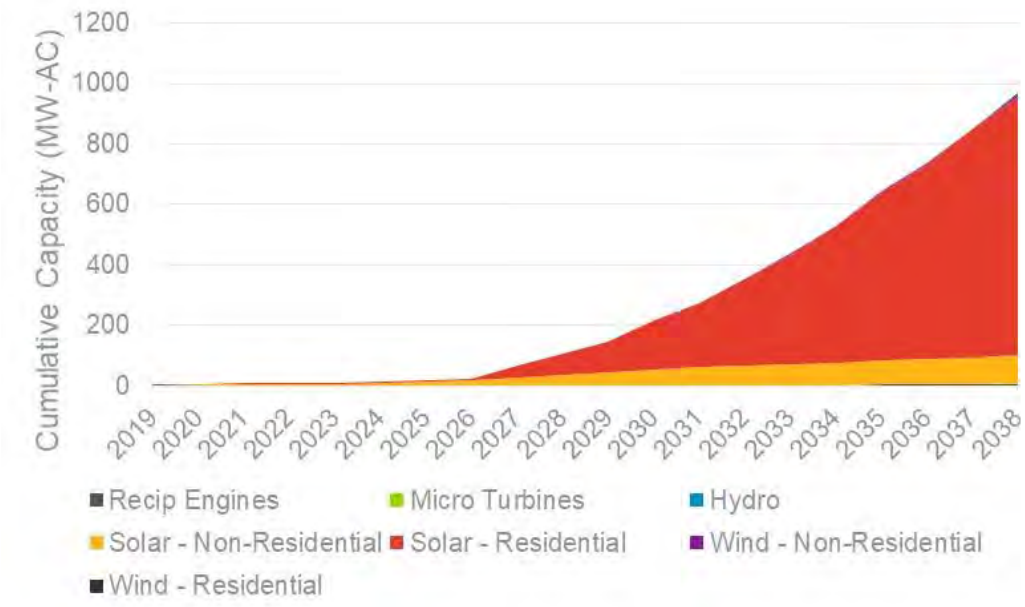
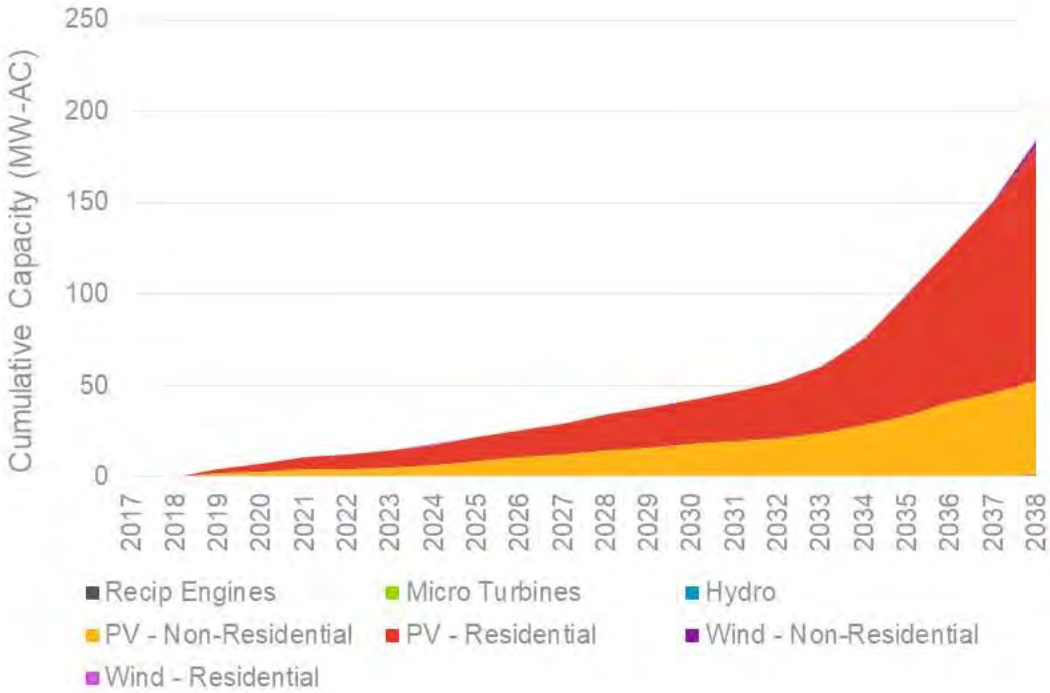


Figure 22 Cumulative Capacity Installations by Technology (MW AC), Oregon Low Case



1.8.4 Utah

PacifiCorp's Utah customers are projected to install about 560 MW of PG capacity over the next two decades in the base case, averaging 28 MW annually. Solar is responsible for most PG installations over

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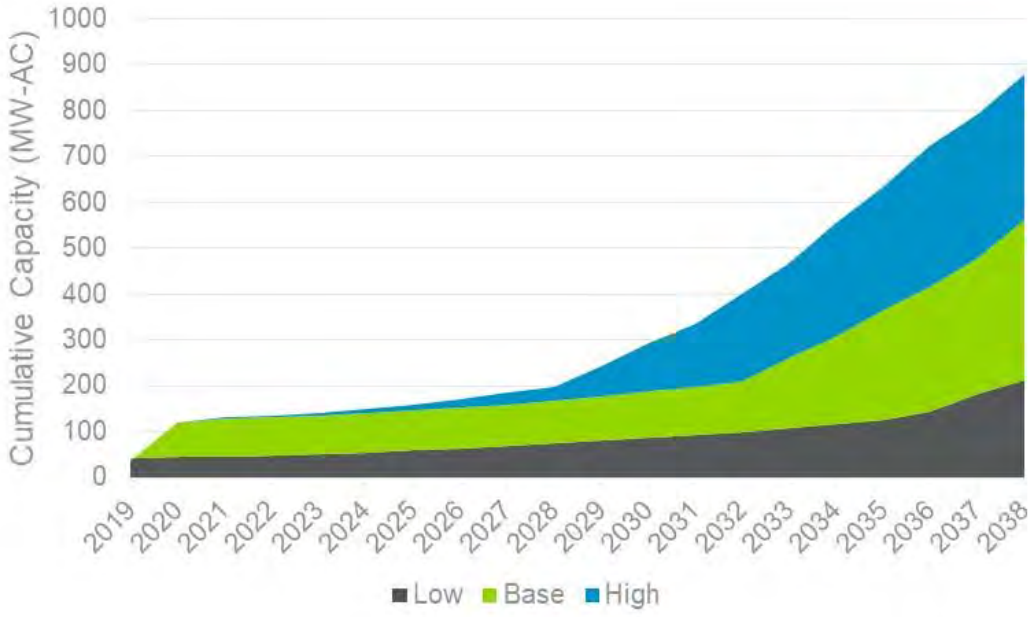
the horizon of this study, with reciprocating engines being installed in small numbers in future years. Utah has the strongest solar resource in PacifiCorp's territory and system costs are lower than in other states due to Utah's larger and more mature market.

The projection in the early years is dominated by residential customers adopting solar. The state Renewable Energy Systems Tax Credit applies to all technologies evaluated and has an impact on solar adoption. Solar adoption declines dramatically in 2020 as the ITC ratchets down. In 2025 projected capacity installation increases as solar prices continue to decline and utility rates escalate (benchmarked to inflation).

The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136.[25] The value of generated energy takes into consideration the recently approved compensation for exported energy included in the tariff. Additionally, the forecast installations for years 2019 and 2020 in the base and high case reflects the capacity cap included within Schedule 136, while low case reflects the assumptions as outlined in Table 11.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 23. The 560 MW from the base case decreases by 62% to 213 MW in the low case and increases by 56% to 879 MW in the high case.

Figure 23. Cumulative Capacity Installations by Scenario (MW AC), Utah



[25] Utah Docket 14-035-114

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Figure 24. Cumulative Capacity Installations by Technology (MW AC), Utah Base Case

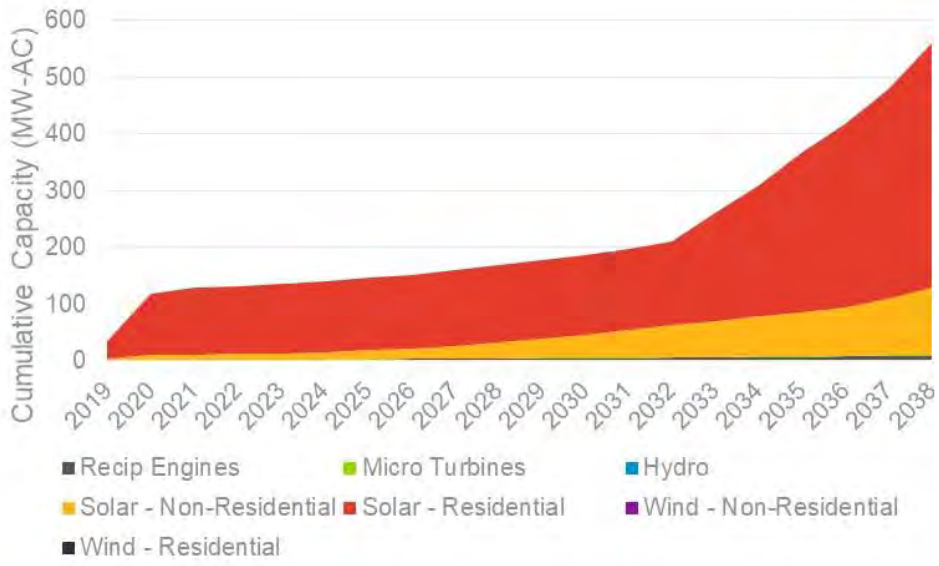

Figure 25. Cumulative Capacity Installations by Technology (MW AC), Utah High Case

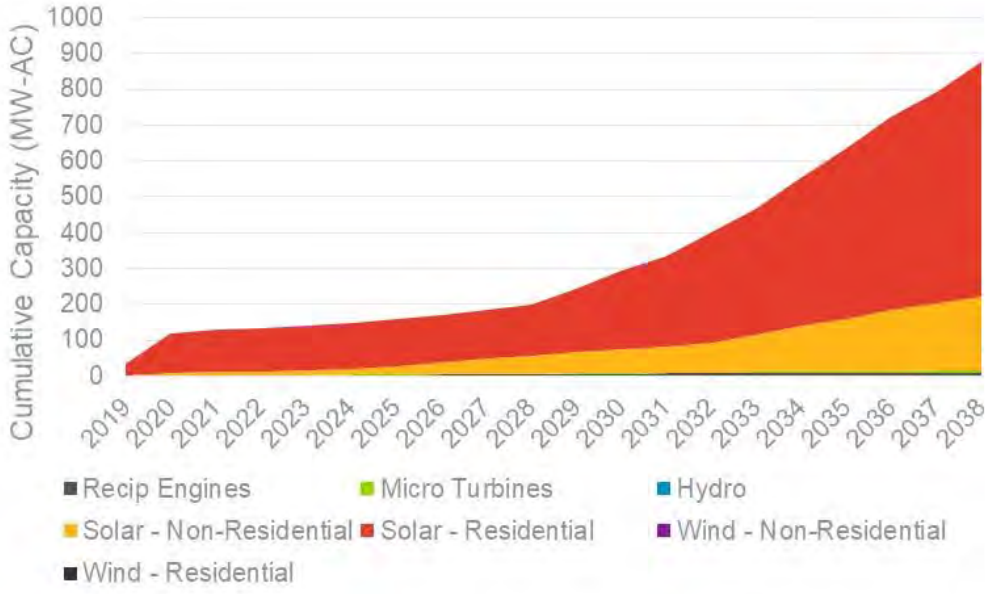

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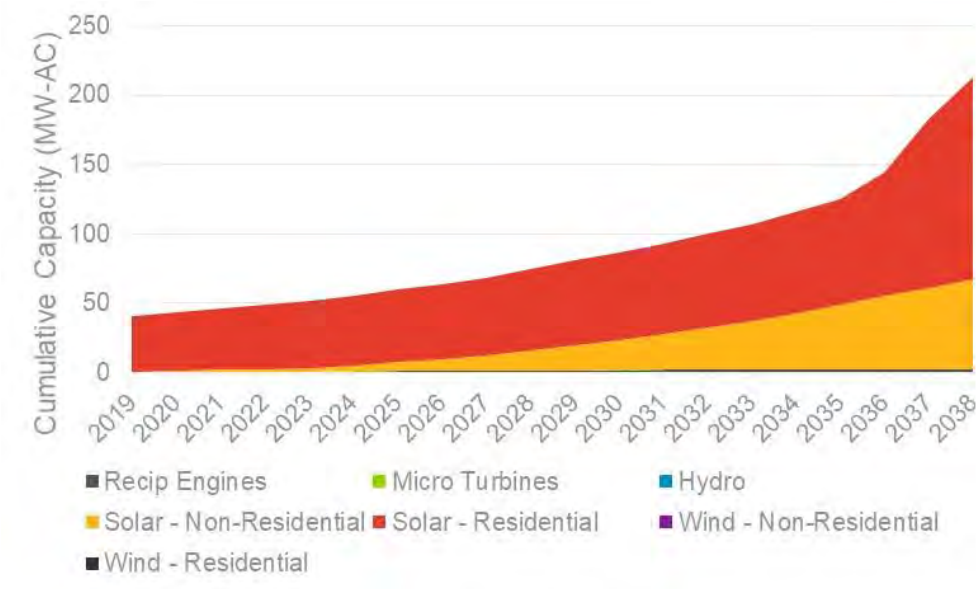
Figure 26. Cumulative Capacity Installations by Technology (MW AC), Utah Low Case



1.8.5 Washington

PacifiCorp's Washington customers are expected to install about 59.6 MW of PG capacity over the next two decades in the base case, averaging 2.98 MW annually. Solar is responsible for most PG installations over the horizon of this study, with reciprocating engines being installed in small numbers in future years. Washington does not have a very strong solar resource, yet the lucrative Feed-In-Tariff in Washington, which extends through 2021, should drive the solar market in the near term. The solar market is driven by non-residential solar installations, most likely due to the lower cost of installing larger systems. Solar adoption declines dramatically in 2020 as the ITC ratchets down. In 2025, installation capacity increases as solar prices continue to decline and utility rates escalate (benchmarked to inflation).

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 27. The 59.6 MW from the base case decreases by 35% to 38.5 MW in the low case and increases by 83% to 109 MW in the high case.

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Figure 27. Cumulative Capacity Installations by Scenario (MW AC), Washington

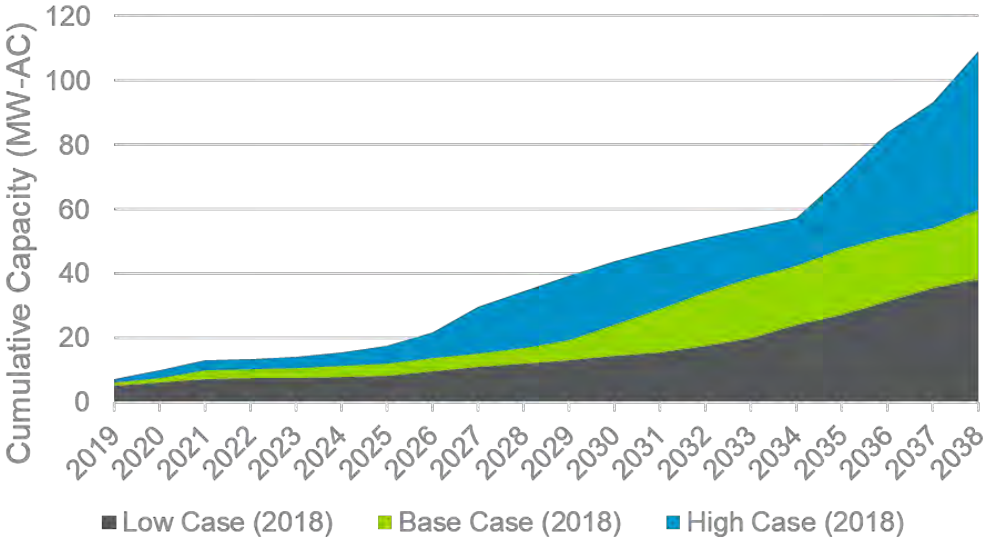

Figure 28. Cumulative Capacity Installations by Technology (MW AC), Washington Base Case

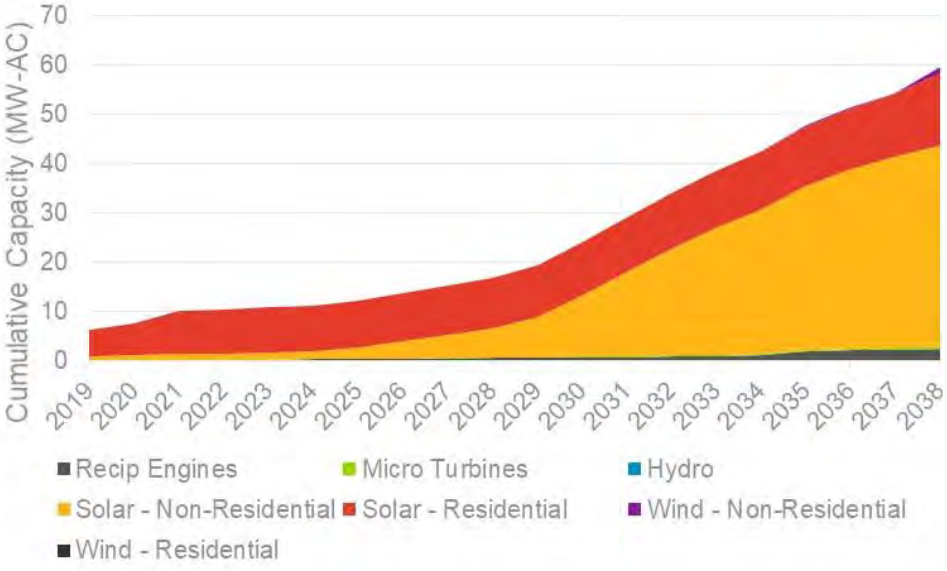

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Figure 29. Cumulative Capacity Installations by Technology (MW AC), Washington High Case

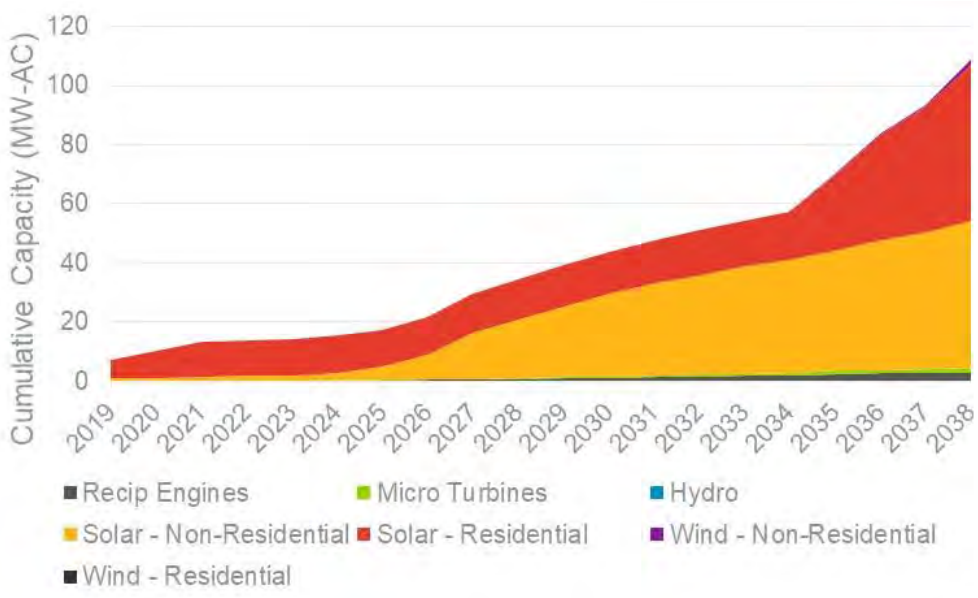
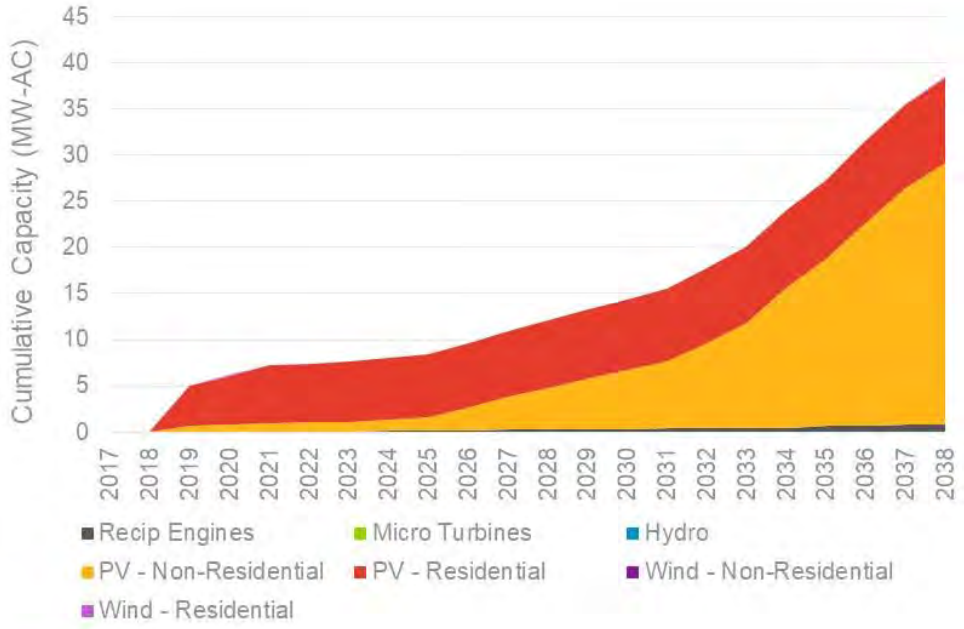


Figure 30. Cumulative Capacity Installations by Technology (MW AC), Washington Low Case



1.8.6 Wyoming

PacifiCorp's Wyoming customers are projected to install about 114 MW of capacity over the next two decades in the base case, averaging about 5.7 MW annually. Solar is responsible for most PG

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installations over the horizon of this study, with reciprocating engines, and small wind being installed in small numbers in future years. Wyoming does not have any state incentives promoting the installation of PG. Similar to other states, the ratcheting down of the Federal ITC from 2020 to 2022 has a negative impact on annual capacity installations but in 2023 the market begins to grow at a faster pace, driven by escalating electricity rates (benchmarked to inflation) and declining technology costs. Both residential and non-residential solar installations are responsible for the majority of PG growth over the horizon of this study.

While the low and high scenarios follow similar market trends as the base case, the cumulative installations over the planning horizon differ significantly, as shown in Figure 31. The 114 MW from the base case decreases by 40% to 68 MW in the low case and increases by 45% to 165 MW in the high case.

Figure 31. Cumulative Capacity Installations by Scenario, Wyoming

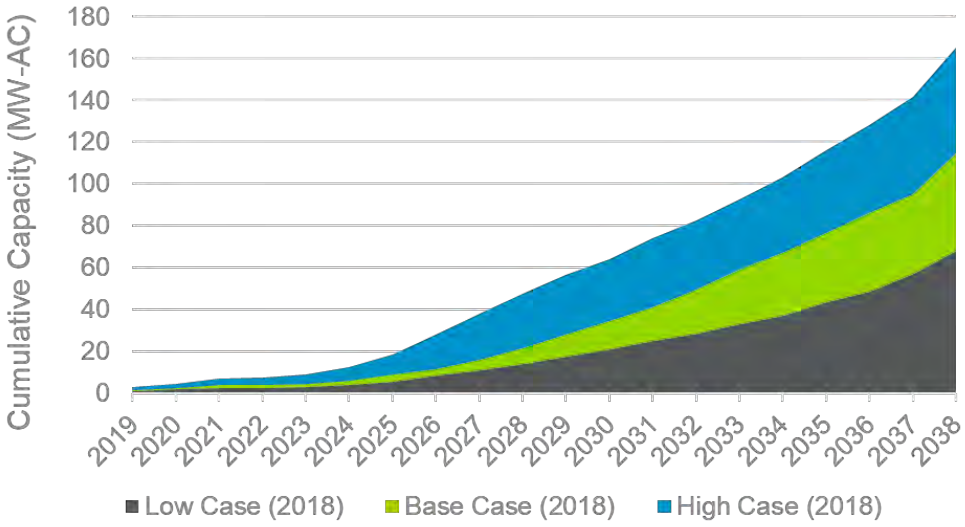

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Figure 32. Cumulative Capacity Installations by Technology (MW AC), Wyoming Base Case

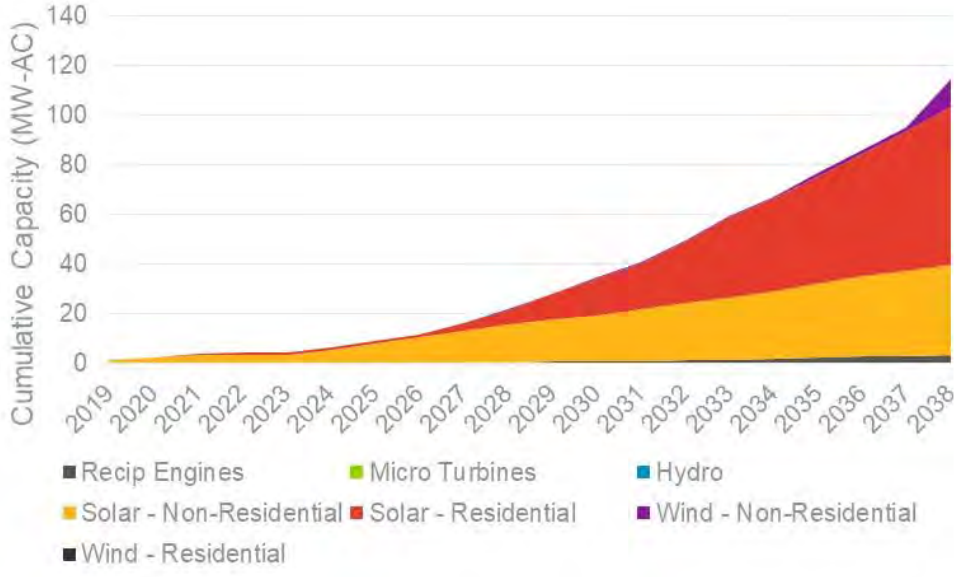

Figure 33. Cumulative Capacity Installations by Technology, Wyoming High Case

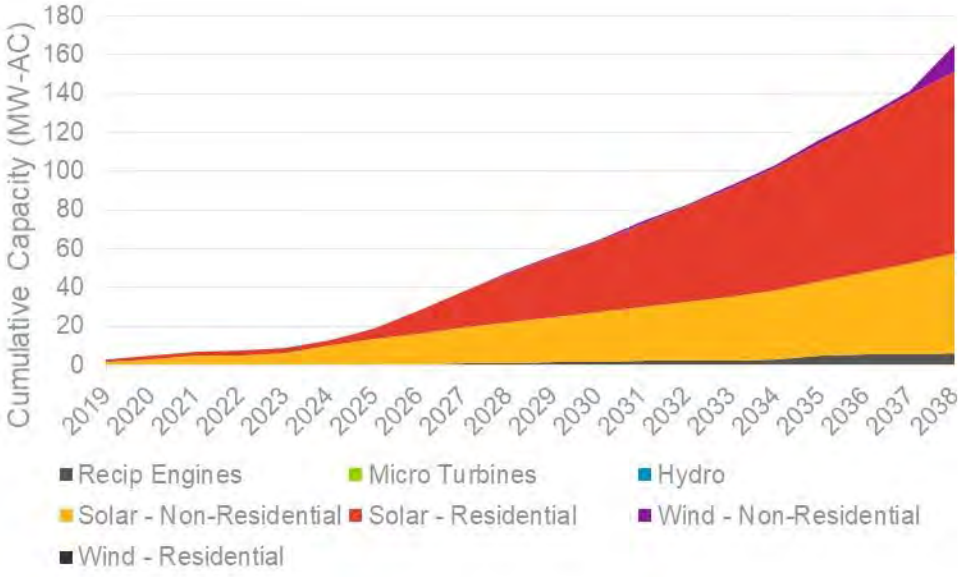

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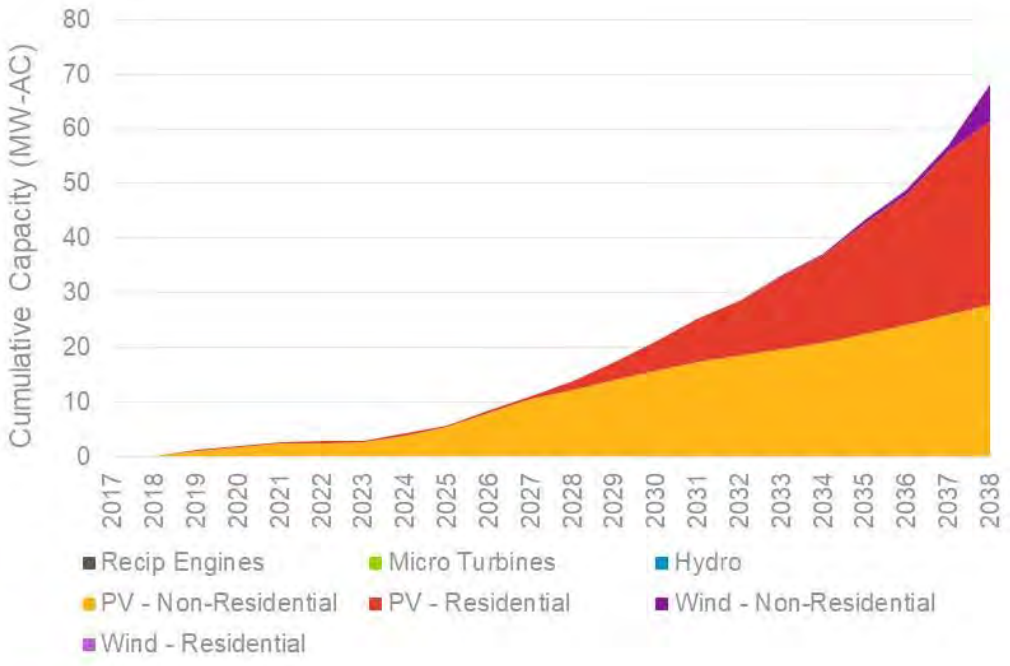
Figure 34. Cumulative Capacity Installations by Technology (MW AC), Wyoming Low Case



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APPENDIX A. CUSTOMER DATA

Table 14 California

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	35,741	374,836	0.166
Commercial	7,262	226,557	0.151
Industrial	117	57,571	0.137
Irrigation	1,841	96,201	0.132

Table 15 Idaho

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	63,910	697,043	0.132
Commercial	8,868	517,881	0.089
Industrial	608	1,712,919	0.072
Irrigation	5,025	643,351	0.091

Table 16 Oregon

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	507,660	5,587,970	0.101
Commercial	67,474	5,244,915	0.091
Industrial	1,540	1,700,386	0.078
Irrigation	7,725	332,594	0.096

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Table 17 Utah

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	807,897	6,824,025	0.110
Commercial	87,524	8,766,980	0.058
Industrial	4,892	7,725,402	0.065
Irrigation	3,249	222,757	0.077

Table 18 Washington

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	109,376	1,582,882	0.099
Commercial	16,021	1,528,895	0.084
Industrial	477	753,191	0.072
Irrigation	5,057	160,403	0.087

Table 19 Wyoming

Rate Class	# Customers	2018 MWh Sales	Avg. Rates ($/kWh)
Residential	115,479	1,016,366	0.119
Commercial	23,010	1,382,275	0.090
Industrial	2,064	6,878,595	0.066
Irrigation	764	24,564	0.092

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APPENDIX B. SYSTEM CAPACITY ASSUMPTIONS

Table 20 Access Factors (%)

Technology	CA	ID	OR	UT	WA	WY
Recip. Engines	N/A	N/A	N/A	N/A	N/A	N/A
Micro Turbines	N/A	N/A	N/A	N/A	N/A	N/A
Small Hydro	N/A	N/A	N/A	N/A	N/A	N/A
PV - Com	42%	42%	42%	42%	42%	42%
PV - Res	35%	35%	35%	35%	35%	35%
Wind - Com	5%	5%	8%	16%	8%	51%
Wind - Res	5%	5%	8%	16%	8%	51%

Table 21 California (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	2	N/A	N/A	28
Micro Turbines	2	N/A	N/A	28
Small Hydro	500	N/A	N/A	500
PV - Com	18	29	N/A	212
PV - Res	N/A	N/A	6	N/A
Wind - Com	10	16	N/A	113
Wind - Res	N/A	N/A	3	N/A

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Table 22 Idaho (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	4	N/A	N/A	185
Micro Turbines	4	N/A	N/A	185
Small Hydro	500	N/A	N/A	500
PV - Com	31	68	N/A	250
PV - Res	N/A	N/A	6	N/A
Wind - Com	29	62	N/A	1515
Wind - Res	N/A	N/A	6	N/A

Table 23 Oregon (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	6	N/A	N/A	110
Micro Turbines	6	N/A	N/A	110
Small Hydro	500	N/A	N/A	500
PV - Com	25	32	N/A	100
PV - Res	N/A	N/A	6	N/A
Wind - Com	30	17	N/A	584
Wind - Res	N/A	N/A	4	N/A

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Table 24 Utah (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	7	N/A	N/A	150
Micro Turbines	7	N/A	N/A	150
Small Hydro	500	N/A	N/A	500
PV - Com	58	39	N/A	130
PV - Res	N/A	N/A	5	N/A
Wind - Com	56	N/A	N/A	938
Wind - Res	N/A	N/A	5	N/A

Table 25 Washington (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	6	N/A	N/A	88
Micro Turbines	6	N/A	N/A	88
Small Hydro	500	N/A	N/A	500
PV - Com	65	21	N/A	250
PV - Res	N/A	N/A	10	N/A
Wind - Com	41	13	N/A	655
Wind - Res	N/A	N/A	6	N/A

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Table 26 Wyoming (kW AC)

Technology	Commercial	Irrigation	Residential	Industrial
Recip. Engines	150	N/A	N/A	150
Micro Turbines	150	N/A	N/A	150
Small Hydro	500	N/A	N/A	500
PV - Com	25	17	N/A	150
PV - Res	N/A	N/A	5	N/A
Wind - Com	23	11	N/A	1192
Wind - Res	N/A	N/A	3	N/A

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APPENDIX C. WASHINGTON HIGH-EFFICIENCY COGENERATION LEVELIZED COSTS

Section 480.109.100 of the Washington Administrative Code[26] 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. To supplement the analysis in the main body of this report addressing reliability and feasibility, this appendix, analyzes the levelized cost of energy (LCOE) of these resources, for use in cost-effectiveness analysis.

Key assumptions for the analysis are presented in Table 27 and Table 28. It is worth noting that the LCOE calculation is for the electrical generation component only and the cost of the heat recapture and recovery was taken out of the total installed system cost. PacifiCorp provided the natural gas pricing and the weighted average cost of capital (WACC) assumptions.

C.1 Key Assumptions

Table 27 Reciprocating Engines LCOE – Key Assumptions[27]

DG Resource Costs	Units	2019	2028	2038	Notes
Installed System Cost	$/W	$2.67/W	$2.77/W	$2.88/W	• EPA, Catalog of CHP Technologies, March 2015, pg. 2-15 • Assumed cost for electrical generation only, system cost was reduced by 10% to exclude heating generation costs.
Asset Life	Years	25	25	25	
Capacity Factor	%	85%	85%	85%	Navigant Assumption
Variable O&M	$/MWh	$20	$20	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MMBtu	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	Provided by PacifiCorp
WACC	%	6.57%	6.57%	6.57%	Provided by PacifiCorp

[26] http://apps.leg.wa.gov/WAC/default.aspx?cite=480-109-100

[27] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

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Table 28 Micro-turbines LCOE – Key Assumptions[28]

DG Resource Costs	Units	2019	2028	2038	Notes
Installed System Cost	$/W	$2.56/W	$2.55/W	$2.54/W	• EPA, Catalog of CHP Technologies, March 2015, pg. 2-15 • Assumed cost for electrical generation only, system cost was reduced by 5% to exclude heating generation costs.
Asset Life	Years	25	25	25	Assumption
Capacity Factor	%	85%	85%	85%	Assumption
Variable O&M	$/MWh	$20	$20	$20	ICF International Inc., Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment, pg. 92
Fuel Cost	$/MMBtu	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	PacifiCorp Gas Forecast	Provided by PacifiCorp
WACC	%	6.57%	6.57%	6.57%	Provided by PacifiCorp

C.2 Results

The results of the LCOE analysis are presented in Table 29, with levelized costs estimated to range from $92/MWh to $115/MWh over the forecast period, varying by year and technology.

Table 29 LCOE Results – Electric Component Only

Technology	Units	2017	2026	2036
Reciprocating Engines	$/MWh	91.1	103.4	115.0
Microturbines	$/MWh	92.5	101.8	111.6

[28] EPA, Catalog of CHP Technologies: www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf; ICF, Combined Heat and Power Policy Analysis, www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

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APPENDIX D. DETAILED NUMERIC RESULTS

D.1 Utah

Table 30. Utah – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.3	0.3	0.3	0.3	0.4	0.5	0.4	0.5	0.6	0.3	0.5	0.5	0.2	0.6	0.5	0.3	0.7	0.5	0.4	0.5
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	31.4	77.6	9.3	2.5	2.5	2.8	2.2	2.0	2.5	3.1	2.6	2.8	2.8	4.0	42.0	41.3	48.3	43.1	46.2	62.8
PV	Commercial	2.3	6.2	0.3	0.3	0.3	1.4	2.0	1.3	4.0	5.0	5.0	4.6	4.5	4.9	4.9	4.5	4.7	5.1	12.7	17.9
PV	Industrial	0.4	0.3	0.4	0.1	0.1	0.5	0.7	0.5	0.6	0.7	1.3	1.8	2.6	3.3	1.9	2.3	2.1	1.6	1.4	1.1
PV	Irrigation	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.4	0.5	0.5	0.4	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Table 31. Utah – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	2067	2214	2513	2444	3023	3907	3257	3923	4172	1919	3629	3390	1496	4459	3989	2275	5401	3675	3141	3821
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	737	739	891	14	15	607	386	1055	796	61	365	454	45	583	761	440	1734	1806	1408	1634
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	66047	163371	19580	5207	5279	5893	4569	4264	5240	6445	5388	5827	5927	8331	88522	86962	101780	90825	97299	132218
PV	Commercial	4798	13016	575	718	728	2963	4131	2654	8412	10447	10621	9604	9534	10334	10258	9449	9906	10696	26686	37792
PV	Industrial	806	537	808	181	183	1112	1425	1039	1307	1402	2681	3698	5578	6903	4084	4901	4340	3333	2879	2334
PV	Irrigation	72	90	106	35	36	86	205	135	211	227	221	230	182	518	490	908	950	974	917	800
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	70
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 32. Utah – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.2	0.1	0.2	0.0	0.0	0.2	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.2	0.1	0.0	0.2	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	40.2	2.1	1.8	2.0	2.0	2.3	1.8	1.9	2.0	2.5	2.1	2.3	2.3	2.8	2.3	2.8	3.0	12.9	33.0	24.4
PV	Commercial	0.3	0.3	0.3	0.3	0.3	0.9	2.1	1.3	1.8	2.8	3.5	2.9	3.6	3.1	3.1	4.2	3.6	3.8	3.7	3.4
PV	Industrial	0.1	0.3	0.3	0.1	0.1	0.4	0.7	0.4	0.6	0.6	0.5	0.5	0.4	0.9	1.2	1.9	2.3	2.4	1.7	2.1
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 33. Utah – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	1393	815	1527	27	153	1556	820	1403	1680	999	1385	975	472	1199	959	261	1120	1108	927	670

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Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	385	153	112	8	8	15	0	4	8	21	9	13	14	27	14	26	28	37	23	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	84618	4421	3809	4241	4299	4800	3721	3994	4268	5249	4388	4746	4827	5920	4908	5953	6215	27176	69416	51343
PV	Commercial	735	611	548	685	695	1936	4479	2656	3703	5890	7343	6161	7592	6634	6514	8768	7489	8089	7875	7190
PV	Industrial	159	542	627	165	167	848	1386	865	1267	1171	949	984	932	1974	2446	3996	4846	5021	3490	4350
PV	Irrigation	34	72	76	34	35	45	201	135	208	186	142	147	176	154	145	163	170	287	384	363
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	27
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 34. Utah – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.6	0.7	0.7	0.6	0.7	0.5	0.6	0.5	0.5	0.6	0.4	0.4	0.3
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.1	0.1	0.2	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.3	0.6	0.6	1.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	31.4	77.6	10.5	3.0	3.0	3.4	2.6	2.4	3.0	3.7	37.1	41.3	35.7	52.5	44.6	65.4	57.8	65.0	49.5	67.8
PV	Commercial	2.3	6.2	0.4	0.4	0.9	3.1	7.2	5.7	7.1	4.8	4.8	5.0	4.1	9.7	18.9	22.2	17.4	21.7	15.4	15.9
PV	Industrial	0.4	0.3	0.4	0.1	0.4	1.0	1.0	1.5	3.8	3.0	2.3	2.0	1.4	1.6	1.1	1.5	1.4	1.7	1.5	2.1
PV	Irrigation	0.0	0.0	0.1	0.0	0.0	0.1	0.2	0.1	0.2	0.3	0.3	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 35. Utah – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	2143	2550	2997	3229	3986	4477	4655	4195	5525	5016	4566	5092	3895	4590	3874	3741	4216	3317	2669	2548
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	904	876	1218	17	1032	1586	1377	1681	1818	1448	1740	1681	1295	2126	1650	1650	1919	4306	4311	7285
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	66047	163371	22026	6274	6359	7100	5504	5137	6313	7764	78119	87069	75261	110677	94037	137753	121666	136974	104183	142724
PV	Commercial	4798	13016	792	755	1830	6616	15157	12058	14868	10165	10064	10494	8697	20401	39833	46730	36685	45636	32442	33541
PV	Industrial	806	537	854	196	743	2012	2034	3192	8055	6357	4743	4255	2898	3355	2402	3058	2897	3570	3094	4389
PV	Irrigation	72	90	111	37	38	295	354	203	379	582	706	1095	828	832	756	731	679	528	580	365
Wind	Residential	0	0	0	0	0	0	0	-1	0	0	0	0	0	0	0	0	0	0	0	80
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

D.2 Oregon

Table 36. Oregon – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.5	0.4	0.4	0.7
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

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Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	2.5	2.1	2.2	1.6	1.7	1.7	1.7	1.8	2.2	3.1	2.9	11.4	20.2	27.1	33.9	41.6	52.4	41.3	45.1	50.0
PV	Commercial	2.2	1.0	0.9	0.2	0.3	2.0	1.8	1.9	1.7	1.8	1.7	3.5	4.7	9.1	7.1	6.7	4.7	5.4	3.6	3.2
PV	Industrial	0.1	0.0	0.1	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.5	0.6	0.7	0.7	0.6
PV	Irrigation	0.3	0.1	0.1	0.0	0.1	0.2	0.3	0.2	0.3	0.2	0.6	1.1	1.0	1.0	0.9	0.7	0.7	0.5	0.4	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.4	0.1	0.1	5.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4

Table 37. Oregon – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	255	302	370	101	518	599	641	803	1259	1424	1338	1397	1623	1257	1386	1394	3687	2823	2791	4964
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1389
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	4066	3364	3595	2617	2690	2778	2783	2871	3491	4897	4706	18274	32353	43453	54434	66701	83996	66306	72260	105385
PV	Commercial	3449	1674	1438	256	418	3157	2834	2974	2681	2834	2768	5686	7606	14623	11403	10677	7604	8702	5755	6698
PV	Industrial	157	74	83	14	39	126	146	278	290	271	272	282	240	254	248	726	1007	1168	1097	1296
PV	Irrigation	532	227	229	43	142	377	423	389	454	365	941	1684	1671	1633	1445	1043	1150	855	721	888
Wind	Residential	30	2	-1	27	0	0	0	0	0	1	0	0	0	0	11	25	25	25	20	868
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	26	167	156	164	173	841	202	161	7613
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	4	8	9	10	11	11	12	50	11	11	558

Table 38. Oregon – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	2.2	2.1	2.1	1.6	1.7	1.7	1.7	1.8	1.8	2.6	2.6	2.6	2.7	2.8	6.3	11.4	18.4	17.9	20.6	23.6

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PV	Commercial	1.9	0.7	1.0	0.1	0.2	1.3	1.7	1.8	1.6	1.5	1.2	1.5	1.1	1.2	1.8	3.2	4.2	6.2	4.3	6.0
PV	Industrial	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.3	0.1	0.1	0.0	0.0	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.6	0.8	0.6	0.9	0.6	0.8
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.1	0.1	2.6
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

Table 39. Oregon – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	12	117	170	0	0	103	320	358	424	491	533	511	464	545	457	536	1769	493	445	259
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	3600	3352	3351	2597	2667	2752	2763	2848	2912	4098	4122	4238	4350	4496	10131	18216	29544	28670	33055	49628
PV	Commercial	3062	1060	1643	235	259	2097	2744	2885	2598	2352	1877	2345	1835	1962	2857	5060	6703	9881	6867	12639
PV	Industrial	154	63	72	13	24	112	110	126	246	225	189	195	191	203	158	210	216	189	179	237
PV	Irrigation	484	216	218	40	44	349	412	378	388	295	339	289	411	719	922	1359	977	1404	936	1625

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Wind	Residential	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	278
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	599	145	144	3794
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	58	8	10	339

Table 40. Oregon – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.1	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.4	0.6	2.3	0.6	0.5	0.3
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.3
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.4	0.6	0.8	0.2	0.3	0.3	0.6	2.9	32.9	27.2	33.5	62.1	52.2	72.6	75.1	88.7	105.5	87.9	109.0	103.2
PV	Commercial	2.2	1.1	1.3	0.2	1.2	2.5	2.5	3.0	7.6	8.6	6.8	6.2	5.3	4.6	3.1	3.6	3.0	3.5	3.8	4.7
PV	Industrial	0.1	0.0	0.1	0.0	0.1	0.2	0.2	0.3	0.2	0.2	0.3	0.5	0.7	0.8	0.6	0.5	0.5	0.3	0.3	0.3
PV	Irrigation	0.3	0.2	0.2	0.0	0.2	0.4	0.3	1.0	1.4	1.2	0.9	0.8	0.6	0.5	0.4	0.5	0.5	0.5	0.7	0.9
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.4	0.1	0.1	6.7
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5

Table 41. Oregon – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	301	358	598	52	732	1182	1311	1419	1729	1770	1650	1870	1694	1700	2840	4386	17299	4434	3691	2312
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	1189	1392	1123	1184	2461	1857	2333	2103
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	2292	932	1219	371	409	478	901	4644	52710	43642	53724	99619	83645	116465	120358	142286	169183	140895	174726	217446
PV	Commercial	3577	1770	2121	293	1942	4027	4080	4764	12205	13868	10856	10020	8449	7418	4952	5796	4822	5590	6049	9872
PV	Industrial	162	78	87	16	96	396	379	402	384	262	461	822	1058	1291	942	846	726	539	549	559
PV	Irrigation	547	278	285	48	310	599	551	1606	2284	1894	1380	1214	982	743	643	832	788	760	1090	1842
Wind	Residential	36	8	3	39	0	1	0	0	0	1	0	0	21	25	29	25	37	38	37	1456
Wind	Commercial	1	-1	0	0	0	0	0	0	10	137	184	183	200	186	217	195	828	186	205	10000
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	6	9	11	12	13	12	15	11	13	51	12	11	702

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Table 42. Washington – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.8	0.2	0.2	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	5.4	1.1	2.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.3	0.2	0.3	0.3	0.4	0.3	1.8
PV	Commercial	0.7	0.1	0.2	0.1	0.1	0.1	0.6	1.1	1.0	1.0	1.8	3.6	4.1	4.1	3.6	2.7	3.0	2.2	1.9	1.7
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.5	0.6	0.5	0.4	0.4
PV	Irrigation	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.4	0.4	0.4	0.3	0.3	0.2	0.3	0.2	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.8
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

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Table 43. Washington – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	220	266	331	68	370	460	455	540	565	531	556	551	449	693	829	848	6114	1411	1224	1086
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	38	40	65	-1	-1	0	81	187	170	134	226	174	178	265	262	242	752	418	620	523
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	9834	2066	4032	281	331	427	312	407	414	512	382	456	467	562	422	530	554	651	485	3832
PV	Commercial	1294	191	314	165	194	251	1034	1936	1735	1839	3275	6597	7408	7384	6592	4836	5414	4055	3347	3542
PV	Industrial	87	18	11	15	18	23	17	131	220	233	199	241	204	294	484	836	1172	926	640	829
PV	Irrigation	140	21	40	18	21	27	142	206	159	316	588	780	759	726	622	453	413	472	327	369
Wind	Residential	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	163
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	131	50	50	1254
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	5	5	157

Table 44. Washington – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038

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Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.4	0.9	1.0	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
PV	Commercial	0.5	0.1	0.1	0.1	0.1	0.1	0.2	0.9	0.9	0.7	0.8	0.7	0.7	1.8	1.8	3.3	2.4	3.5	3.3	2.2
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
PV	Irrigation	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.3	0.4	0.4	0.3	0.3	0.2
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 45. Washington – Incremental Annual Adoption (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Reciprocating Engine	Industrial	150	162	222	-8	3	246	223	333	304	195	288	285	195	342	228	223	1556	338	290	171
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	7958	1717	1754	191	225	291	213	277	282	348	260	310	318	382	287	361	377	443	330	349
PV	Commercial	939	184	112	156	184	237	392	1650	1685	1277	1453	1262	1186	3178	3208	5993	4384	6387	5954	4641
PV	Industrial	84	17	10	15	17	22	16	21	137	165	160	169	164	143	169	149	155	168	239	475
PV	Irrigation	103	20	33	17	20	26	60	176	180	137	155	198	321	253	606	637	636	462	578	446
Wind	Residential	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	141
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	106
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20

Table 46. Washington – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.5	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.3
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	6.5	2.5	2.7	0.2	0.3	0.3	0.2	0.3	0.3	0.4	0.3	0.3	0.4	0.4	0.3	0.5	9.5	10.6	6.9	9.8
PV	Commercial	0.7	0.1	0.3	0.1	0.1	0.9	1.3	3.2	6.4	3.9	3.4	3.1	2.5	1.9	1.9	1.7	1.9	2.4	2.0	3.2
PV	Industrial	0.1	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.4	0.5	0.6	0.4	0.4	0.3	0.2	0.3	0.2	0.2
PV	Irrigation	0.1	0.0	0.0	0.0	0.0	0.1	0.2	0.5	0.7	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	1.4
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

Table 47. Washington – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	259	341	461	8	446	517	556	986	931	1212	1873	1569	1584	1593	1454	1409	3809	1021	795	677
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	80	99	130	-3	148	205	222	288	303	292	423	546	572	682	591	609	1687	774	1362	2251

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Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	11727	4539	4830	388	458	590	432	562	572	707	528	630	646	777	583	876	17133	19138	12529	20644
PV	Commercial	1339	199	575	174	206	1568	2402	5849	11621	6995	6209	5561	4508	3423	3473	3098	3443	4312	3560	6662
PV	Industrial	113	19	12	16	19	48	298	315	296	391	672	891	1053	807	683	606	438	509	369	441
PV	Irrigation	145	22	88	19	23	175	366	885	1198	688	588	517	345	403	292	339	397	515	433	832
Wind	Residential	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	173
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	62	261	56	45	2043
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	3	6	6	27	5	6	241

D.4 Idaho

Table 48. Idaho – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.1	0.3	0.3	0.4
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.1	0.1	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.9	1.1	1.1	0.3	0.3	0.3	0.3	0.3	2.3	5.0	3.6	5.1	4.4	4.9	5.3	5.9	6.4	7.1	5.3	5.1
PV	Commercial	0.4	0.2	0.2	0.1	0.2	0.3	0.8	1.1	1.5	1.0	1.1	1.0	0.6	0.6	0.6	0.5	0.5	0.7	0.7	0.8
PV	Industrial	0.2	0.1	0.1	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.1	0.4	0.6	0.7	0.6	0.6	0.5	0.4	0.3	0.3
PV	Irrigation	0.5	0.3	0.4	0.1	0.1	0.7	1.0	1.5	1.5	1.5	1.3	0.9	0.9	0.7	0.6	0.7	0.7	0.7	1.0	1.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 49. Idaho – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	314	364	470	50	567	660	728	874	852	786	854	956	684	907	704	678	8049	2373	2225	3307
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	108	360	280	481	465	394	1382	491	430	442
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	10086	2201	2267	614	642	684	584	620	4825	10247	7337	10553	9093	10154	10896	12139	13297	14657	10969	10823
PV	Commercial	830	441	482	115	391	607	1605	2215	3082	1978	2271	2013	1340	1253	1315	1106	942	1346	1534	1745
PV	Industrial	402	186	218	39	68	341	345	315	322	382	285	900	1216	1405	1334	1235	1087	786	674	562
PV	Irrigation	1044	638	805	153	224	1532	2030	3098	3127	2997	2647	1914	1935	1457	1306	1385	1531	1429	2048	2381
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 50. Idaho – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	0.1	0.1	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	4.5	0.2	1.0	0.2	0.3	0.3	0.2	0.2	0.3	3.1	2.3	4.1	2.5	2.7	4.1	3.2	3.5	3.8	3.9	0.7

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PV	Commercial	0.4	0.2	0.2	0.1	0.1	0.3	0.3	0.7	1.0	1.0	1.0	0.7	0.9	0.6	0.6	0.8	0.5	0.5	0.5	0.4
PV	Industrial	0.2	0.1	0.1	0.0	0.0	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.5	0.6	0.4	0.5
PV	Irrigation	0.5	0.3	0.2	0.1	0.2	0.4	0.6	0.8	1.5	1.2	1.2	0.9	0.8	1.0	0.7	0.7	0.6	0.6	0.7	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 51. Idaho – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	183	199	236	3	172	293	314	360	346	316	361	311	244	352	183	448	2641	497	453	415
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	9306	500	2007	507	530	564	482	512	613	6362	4846	8415	5193	5665	8450	6640	7155	7805	8076	1430
PV	Commercial	814	426	469	111	220	668	575	1360	1974	2048	2032	1457	1846	1308	1202	1554	1100	1083	964	889
PV	Industrial	391	176	175	36	37	303	293	348	314	233	275	233	218	233	581	622	1132	1180	817	1124
PV	Irrigation	959	620	515	142	384	745	1187	1737	3132	2551	2468	1758	1596	2105	1397	1380	1323	1308	1472	774

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Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 52. Idaho – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.2	0.3	0.4	0.3	0.4	1.0	0.3	0.2	0.2
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.4	0.1	0.1	0.2
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	5.5	1.2	2.6	0.4	0.4	0.4	2.3	5.5	7.6	4.7	6.6	5.7	6.2	4.9	7.0	5.6	8.1	6.4	6.4	1.4
PV	Commercial	0.4	0.3	0.5	0.1	0.4	1.6	1.6	1.4	1.2	0.6	0.7	0.6	0.5	0.7	0.6	1.0	1.3	1.2	1.4	1.6
PV	Industrial	0.2	0.1	0.1	0.0	0.1	0.2	0.2	0.4	0.8	0.8	0.6	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.4	0.5
PV	Irrigation	0.6	0.5	0.5	0.1	0.6	2.3	1.9	1.7	1.2	0.9	0.7	0.7	0.7	0.9	1.1	1.0	1.7	1.6	1.9	2.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

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Table 53. Idaho – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	362	427	553	197	660	821	915	1009	1076	1254	1863	1613	2359	3307	2452	3241	7409	2218	1426	1172
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	94	113	159	1	81	282	330	424	464	458	519	508	475	789	1024	1205	2994	1009	965	1274
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	11266	2475	5341	792	829	882	4673	11318	15614	9759	13595	11777	12783	10129	14535	11465	16801	13228	13225	2972
PV	Commercial	846	519	1025	133	870	3404	3358	2968	2388	1317	1360	1151	1118	1376	1201	2029	2668	2492	2851	3365
PV	Industrial	443	198	265	44	245	482	452	769	1739	1616	1235	1115	916	669	698	570	597	693	790	991
PV	Irrigation	1234	1030	1055	176	1157	4818	4023	3442	2443	1851	1413	1452	1451	1823	2216	2125	3609	3349	3835	4524
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	26
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	15	189
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	18	16	300

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D.5 California

Table 54. California – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.8	1.1	1.1	0.1	0.1	0.1	0.1	1.6	1.7	2.2	1.8	2.0	2.1	1.7	2.4	1.9	2.0	2.2	2.2	2.5
PV	Commercial	0.4	0.2	0.2	0.0	0.2	0.3	0.2	0.3	0.4	0.4	0.4	0.5	0.6	0.4	0.7	0.9	0.6	1.2	0.7	0.8
PV	Industrial	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.2	0.2
PV	Irrigation	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.3	0.2	0.3	0.4	0.3
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

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Table 55. California – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	115	115	168	49	204	242	199	284	305	220	313	320	164	314	294	105	995	100	326	64
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	102	113	139	56	170	200	218	243	260	281	279	285	285	295	277	287	746	349	326	64
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	3784	2374	2456	121	127	166	125	3392	3737	4790	3911	4220	4559	3540	5174	3997	4307	4754	4696	5202
PV	Commercial	755	531	488	73	446	629	508	581	902	850	929	1099	1224	821	1553	1879	1189	2464	1423	1626
PV	Industrial	191	123	110	17	118	128	119	108	153	148	156	186	205	258	288	355	423	281	525	341
PV	Irrigation	328	201	180	33	215	210	151	198	222	215	222	378	314	397	443	549	357	738	818	534
Wind	Residential	26	-1	3	13	-1	0	-1	-1	-1	2	3	5	3	5	3	3	15	47	54	770
Wind	Commercial	3	0	6	8	9	10	12	12	14	13	12	12	13	11	9	18	137	19	28	1076
Wind	Industrial	0	0	0	1	1	1	1	1	1	2	1	2	1	1	1	3	10	2	2	100
Wind	Irrigation	0	0	1	2	3	4	4	4	5	5	4	5	4	5	3	4	15	8	7	276

Table 56. California – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038

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Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.5	0.7	1.0	0.0	0.0	0.1	0.0	0.8	1.5	1.2	1.2	1.7	1.2	1.3	1.4	1.5	0.9	1.7	1.7	1.11083
PV	Commercial	0.3	0.2	0.2	0.0	0.2	0.2	0.2	0.3	0.3	0.2	0.3	0.2	0.2	0.4	0.3	0.3	0.3	0.4	0.7	0.5
PV	Industrial	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.0	0.1	0.0	0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1
PV	Irrigation	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

Table 57. California – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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Reciprocating Engine	Industrial	92	94	132	37	156	150	190	210	166	228	149	214	212	113	189	75	786	73	39	232
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	72	87	105	46	124	160	156	171	142	181	174	173	169	172	156	161	534	210	195	43
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	3122	1524	2067	99	104	136	67	1799	3228	2528	2612	3571	2648	2889	2892	3175	1924	3675	3671	2340
PV	Commercial	722	510	464	71	461	474	427	627	553	436	669	462	440	935	551	650	726	838	1543	1026
PV	Industrial	179	121	108	17	99	125	108	95	125	84	114	83	132	99	172	121	137	159	285	196
PV	Irrigation	333	174	178	28	183	212	147	180	147	170	165	122	185	143	239	174	196	396	238	284
Wind	Residential	11	6	5	10	0	0	-1	0	0	0	0	0	3	3	3	3	3	3	3	215
Wind	Commercial	2	0	3	7	7	9	9	10	10	11	10	12	10	10	6	8	30	18	16	585
Wind	Industrial	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	4	1	2	59
Wind	Irrigation	0	0	1	2	2	2	2	3	4	4	3	4	3	3	4	3	14	3	3	184

Table 58. California – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.1
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.2	0.0	0.1	0.1
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.8	1.2	1.7	0.1	0.1	0.5	3.2	3.0	2.7	2.4	2.5	1.8	2.8	2.2	2.1	2.4	2.5	2.8	2.7	1.8
PV	Commercial	0.4	0.3	0.2	0.0	0.3	0.5	0.6	0.6	0.8	0.7	0.8	0.5	1.0	1.1	0.7	1.4	0.9	1.0	1.0	1.1
PV	Industrial	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.2	0.3	0.2	0.4	0.2	0.2
PV	Irrigation	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.4	0.2	0.5	0.3	0.6	0.4
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3

Table 59. California – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	121	151	187	46	226	269	297	334	360	255	372	381	383	183	353	366	952	440	65	425
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	105	130	160	83	204	242	267	389	340	371	372	381	383	183	353	366	1268	124	410	449

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Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	3849	2658	3562	145	152	1107	6861	6468	5856	5092	5258	3945	5987	4673	4596	5061	5416	5945	5767	3794
PV	Commercial	860	559	519	75	659	1001	1291	1386	1739	1556	1716	1092	2056	2459	1398	2993	1850	2081	2049	2321
PV	Industrial	192	126	113	24	169	181	216	306	320	294	324	380	422	276	527	628	392	809	463	526
PV	Irrigation	319	205	184	42	272	274	310	431	453	421	682	328	608	740	821	523	1073	695	1304	829
Wind	Residential	55	-1	-1	19	-1	-1	-1	-1	-1	0	-1	-1	-1	43	86	68	119	91	96	2198
Wind	Commercial	2	0	7	9	10	12	12	14	15	15	13	22	21	21	44	33	132	26	21	1264
Wind	Industrial	0	0	0	1	1	1	1	2	2	2	2	3	3	3	3	3	9	2	3	122
Wind	Irrigation	1	0	1	3	3	4	4	5	5	6	5	5	5	5	4	4	44	19	12	431

D.6 Wyoming

Table 60. Wyoming – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.7	0.2	0.2	0.5
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.1	0.6	0.0	0.0	0.0	0.0	0.0	2.0	2.8	4.4	4.5	4.0	6.1	7.1	5.2	5.7	6.4	6.8	7.4
PV	Commercial	0.8	0.8	0.8	0.1	0.1	1.5	2.2	2.2	2.1	2.0	1.3	1.2	1.2	1.0	0.9	0.8	1.2	1.6	1.3	1.5
PV	Industrial	0.3	0.2	0.2	0.0	0.0	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.8	1.2	1.3	1.3	1.2	1.1	0.7	0.6
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.5	0.1	0.1	9.0
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

Table 61. Wyoming – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	246	1402	1802	1728	1885	1850	1689	1752	5406	1506	1368	3452
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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PV	Residential	480	118	1253	87	87	98	70	100	4395	5996	9603	9698	8631	13127	15412	11311	12422	13949	14681	15538
PV	Commercial	1831	1639	1672	257	256	3290	4770	4854	4611	4264	2910	2688	2674	2178	1981	1827	2625	3395	2848	3255
PV	Industrial	716	345	416	64	80	676	764	620	732	676	654	686	1829	2576	2879	2815	2575	2320	1518	1303
PV	Irrigation	62	31	50	7	7	91	111	110	102	92	63	58	48	50	47	57	52	85	71	118
Wind	Residential	7	3	2	8	0	0	0	0	0	0	0	1	3	4	6	5	5	5	5	248
Wind	Commercial	-1	-1	-1	0	0	0	-1	0	66	228	225	251	270	289	245	301	1237	289	212	13392
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	1	4	4	4	5	5	5	5	5	21	5	5	249

Table 62. Wyoming – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	1.1	1.7	2.1	2.5	2.1	3.4	2.7	4.3	3.4	6.2	3.5
PV	Commercial	0.8	0.4	0.5	0.1	0.2	0.9	1.2	2.2	2.3	1.3	1.7	1.2	1.4	1.0	0.9	0.9	0.9	0.9	0.8	0.8

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PV	Industrial	0.2	0.1	0.2	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.2	0.2	0.2	0.3	0.6	0.8	1.1	1.1
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.6	0.1	0.1	5.7
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1

Table 63. Wyoming – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	424	115	111	62	62	70	49	59	200	2408	3576	4531	5511	4454	7260	5749	9328	7377	13471	7414
PV	Commercial	1652	897	1145	222	325	1923	2671	4858	4979	2902	3626	2590	3059	2229	1922	1957	1886	1964	1670	1612
PV	Industrial	522	325	325	57	57	559	657	599	712	559	439	561	434	471	445	732	1260	1702	2385	2335
PV	Irrigation	42	28	38	6	6	51	98	90	113	87	58	57	66	48	42	43	42	45	39	39
Wind	Residential	5	2	0	5	0	0	0	0	0	0	0	0	0	0	1	3	3	3	3	134

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Wind	Commercial	-1	0	0	0	0	0	0	0	0	0	0	0	0	0	226	202	1389	202	239	8429
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	1	4	4	4	24	5	3	165

Table 64. Wyoming – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reciprocating Engine	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.6	1.7	0.5	0.5	0.4
Reciprocating Engine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Micro Turbine	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV	Residential	1.1	0.5	1.0	0.1	0.1	0.1	2.6	6.1	7.0	6.7	5.7	5.0	7.1	6.3	6.6	7.4	8.2	6.5	9.2	7.0
PV	Commercial	1.4	1.0	1.2	0.1	1.2	3.1	2.7	2.2	1.6	1.3	1.0	1.2	1.2	1.2	1.9	1.8	2.2	3.8	3.2	3.8
PV	Industrial	0.4	0.2	0.2	0.0	0.2	0.4	0.5	0.4	1.0	1.3	1.5	1.2	1.0	0.9	0.7	0.6	0.5	0.6	0.6	0.7
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Wind	Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.5	0.1	0.1	11.1
Wind	Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2

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Table 65. Wyoming – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Reciprocating Engine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reciprocating Engine	Industrial	0	0	0	0	0	1057	1406	1674	1895	1933	2234	2099	2173	2264	1818	4194	12773	4049	3806	3093
Reciprocating Engine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Micro Turbine	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Hydro	Irrigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PV	Residential	2289	1013	2190	162	161	182	5643	13270	15206	14495	12445	10734	15361	13570	14349	16133	17679	14178	19965	14671
PV	Commercial	3041	2175	2652	315	2556	6675	5854	4811	3411	2785	2184	2491	2702	2661	4060	3904	4674	8277	6952	7945
PV	Industrial	878	439	444	73	530	974	982	941	2271	2751	3320	2574	2209	1968	1575	1216	1182	1303	1303	1527
PV	Irrigation	90	61	64	8	63	151	127	103	74	56	52	61	67	91	78	98	169	156	174	199
Wind	Residential	9	5	3	10	0	0	0	0	0	0	3	6	6	5	6	5	7	6	5	326
Wind	Commercial	-2	-1	-1	0	0	0	98	204	245	287	278	340	316	287	322	331	1213	311	328	16419
Wind	Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	Irrigation	0	0	0	0	0	0	4	4	5	5	6	6	5	6	6	6	21	6	5	308

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APPENDIX P – RENEWABLE RESOURCES ASSESSMENT

A study on renewable resources and energy storage was commissioned to support PacifiCorp's 2019 Integrated Resource Plan (IRP). The 2018 Renewable Resources Assessment, prepared by Burns & McDonnell Engineering Company, Inc. (BMcD) 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. BMcD evaluated energy storage options of Pumped Hydro Energy Storage, Compressed Air Energy Storage, Lithium Ion Battery, Flow Battery, as well as wind and solar and combinations of these resource types.

This report compiles the assumptions and methodologies used by BMcD 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.

2018 Renewable Resources Assessment

PacifiCorp

2018 Renewable Resources Assessment
Project No. 109571

Revision 3
October 2018

2018 Renewable Resources Assessment

prepared for

PacifiCorp
2018 Renewable Resources Assessment
Salt Lake City, Utah

Project No. 109571

Revision 3
October 2018

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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1.0 INTRODUCTION

PacifiCorp (Owner) retained Burns & McDonnell Engineering Company (BMcD) to evaluate various renewable energy resources in support of the development of the Owner's 2019 Integrated Resource Plan (IRP) and associated resource acquisition portfolios and/or products. The 2018 Renewable Resources Assessment (Assessment) 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.

It is the understanding of BMcD that this Assessment will be used as preliminary information in support of the Owner's long-term power supply planning process. Any technologies of interest to the Owner should be followed by additional detailed studies to further investigate each technology and its direct application within the Owner's long-term plans.

1.1 Evaluated Technologies

- Single Axis Tracking Solar
- Onshore Wind
- Energy Storage
  - Pumped Hydro Energy Storage (PHES)
  - Compressed Air Energy Storage (CAES)
  - Lithium Ion Battery
  - Flow Battery
- Solar + Energy Storage
- Wind + Energy Storage

1.2 Assessment Approach

This report accompanies the Renewable Resources Assessment spreadsheet files (Summary Tables) provided by BMcD. The Summary Tables are broken out into three separate files for Solar, Wind, and Energy Storage options. The costs are expressed in mid-2018 dollars for a fixed price, turn-key resource implementation. Appendix A includes the Summary Tables.

This report compiles the assumptions and methodologies used by BMcD 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.

1.3 Statement of Limitations

Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD 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.

2.0 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 cost and O&M estimates are stated in mid-2018 US dollars (USD). Escalation is excluded.
- Estimates assume an Engineer, Procure, Construct (EPC) fixed price contract for project execution.
- 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.
- All performance estimates assume new and clean equipment. Operating degradation is excluded.
- Electrical scope is assumed to end at the high side of the generator step up transformer (GSU) unless otherwise specified in the summary table (most notably for CAES and PHES).
- Demolition or removal of hazardous materials is not included.

2.3 EPC Project Indirect Costs

The following project indirect costs are included in capital cost estimates:

- Construction/startup technical service
- Engineering and construction management

- Freight
- Startup spare parts
- EPC fees & contingency

2.4 Owner Costs

Allowances for Owner's costs are included in the pricing estimates. The cost buckets for Owner's costs varies slightly by technology, but is broken out in the summary tables in Appendix A.

2.5 Cost Estimate Exclusions

The following costs are excluded from all estimates:

- Financing fees
- Interest during construction (IDC)
- Escalation
- Performance and payment bond
- Sales tax
- Property taxes and insurance
- Off-site infrastructure
- Utility demand costs
- Decommissioning costs
- Salvage values

2.6 Operating and Maintenance Assumptions

Operations and maintenance (O&M) estimates are based on the following assumptions:

- O&M costs are based on a greenfield facility with new and clean equipment.
- O&M costs are in mid-2018 USD.
- Property taxes allowance included for solar and onshore wind options.
- Land lease allowance included for PV and onshore wind options.
- Li-Ion battery O&M includes costs for additional cells to be added over time.

3.0 SOLAR PHOTOVOLTAIC

This Assessment includes 5 MW, 50 MW, and 200 MW single axis tracking photovoltaic (PV) options evaluated at five locations within the PacifiCorp services area.

3.1 PV General Description

The conversion of solar radiation to useful energy in the form of electricity is a mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. PV cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively (i.e. Phosphorus) and negatively (i.e. Boron) charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. Approximately 15% of the solar energy incident on the solar cell can be converted to electrical energy by a typical silicon solar cell. As the cell ages, the conversion efficiency degrades at a rate of approximately 2% in the first year and 0.5% per year thereafter. At the end of a typical 30-year period, the conversion efficiency of the cell will still be approximately 80% of its initial efficiency.

3.2 PV Performance

BMcD pulled Typical Meteorological Year (TMY) weather data for each site to determine expected hourly irradiance. BMcD then ran simulations of each PV option using PVSYST software. The resultant capacity factors for single axis tracking systems are shown in the Summary Tables. Inverter loading ratios (ILR) for each base plant nominal output at the point of electrical interconnect are indicated in Table 3-1.

Table 3-1: Inverter Loading Ratios in Assessment

Nominal Output	Single-Axis Tracking (SAT) DC/AC Ratio
5 MW	1.32
50 MW	1.46
200 MW	1.46

There are different panel technologies which may exhibit different performance characteristics depending on the site. This assessment assumes poly-crystalline panels. The alternative, thin film technologies, are typically cheaper per panel, but they are also less energy dense, so it’s likely that more panels would be required to achieve the same output. In addition, the two technologies respond differently to shaded

conditions. The two technologies are also impacted differently by current solar tariffs which has also impacted availability of the two.

Appendix B shows the PVSYST model output for a 5 MW block with the input assumptions, losses, and output summary. Appendix C shows an additional output summary page unique for each solar option size and location. TMY data for each site as well as PVSYST 8760 outputs are provided to accompany this report outside of the formal report appendices.

3.3 PV Cost Estimates

Cost estimates were developed using in-house information based on BMcD project experience as an EPC contractor as well as an Owner's Engineer for EPC solar projects. Cost estimates assume an EPC project plus typical Owner's costs. A typical solar project cash flow is included in Appendix F.

PV cost estimates for the single axis tracking systems are included in the Summary Tables. Costs are based on the DC/AC ratios in Table 4-1 above, and $/kW costs, based on the nominal AC output, are shown in Appendix A. The project scope assumes a medium voltage interconnection for the 5 MW options, and a high voltage interconnection for the 50 and 200 MW options. Owner's costs include a switchyard allowance for the larger scale options, but no transmission upgrade costs or high voltage transmission interconnect line costs are included.

PV installed costs have steadily declined for years. The main drivers of cost decreases include substantial module price reductions, lower inverter prices, and higher module efficiency. However, recent US tariffs have had an impact on PV panels and steel imports. Pricing in the summary table is based on actual competitive EPC market quotes since these tariffs have been in place to take into account this impact. The panel tariffs only impact crystalline solar modules, however the availability of CdTe is limited for the next couple years, so it is prudent to assume similar cost increases for thin film panels until the impacts of the tariff are clearer.

The 2018 Assessment excludes land costs from capital and Owner costs. It is assumed that all PV projects will be on leased land with allowances provided in the O&M costs.

3.4 PV O&M Cost Estimate

O&M costs for the PV options are shown in the Summary Tables. O&M costs are derived from BMcD project experience and vendor information. The 2018 Assessment includes allowances for land lease and property tax costs.

The following assumptions and clarifications apply to PV O&M:

- O&M costs assume that the system is remotely operated and that all O&M activities are performed through a third-party contract. Therefore, all O&M costs are modeled as fixed costs, shown in terms of $MM per year.
- Land lease and property tax allowances are included based on in house data from previous projects.
- Equipment O&M costs are included to account for inverter maintenance and other routine equipment inspections.
- BOP costs are included to account for monitoring & security and site maintenance (vegetation, fencing, etc.).
- Panel cleaning and snow removal are not included in O&M costs.
- The capital replacement allowance is a sinking fund for inverter replacements, assuming they will be replaced once during the project life. It is a 15-year levelized cost based on the current inverter capital cost.

3.5 PV Plus Storage

The PV plus storage options combine the PV technology discussed in section 3.0 with the lithium ion batteries described in section 7.0. The battery storage size is set at approximately 25% of the total nominal output of the base solar options, with options for two, four, and eight hours of storage duration.

The storage system is assumed to be electrically coupled to the PV system on the AC side, meaning the PV and storage systems have separate inverters. However, there are use cases such as PV clipping that may be better served by a DC-DC connection. In a DC coupled system, the storage side would have a DC-DC voltage converter and connect to the PV system upstream of the DC-AC inverters. For a clipping application, a DC-DC connection allows the storage system to capture the DC output from the PV modules that may have otherwise been clipped by the inverters. Further study beyond the scope of this assessment would be required to determine the best electrical design for a particular application or site, but at this level of study, the capital costs provided are expected to be suitable for either AC or DC coupled systems.

Capital costs are show as add-on costs, broken out as project and owner's costs. These represent the additional capital above the PV base cost, intended to capture modest savings to account for shared system costs such as transformer(s) and switchgear. In addition, overlapping owner costs are eliminated

or reduced. Finally, a line for O&M add-on costs is also included which can be added with the base PV O&M costs to determine overall facility O&M.

As with the Li-Ion battery options, the co-located storage option assumes an operation profile of one cycle per day, which is used for calculating the O&M costs.

4.0 ON-SHORE WIND

4.1 Wind Energy General Description

Wind turbines convert the kinetic energy of wind into mechanical energy, which can be used to generate electrical energy that is supplied to the grid. Wind turbine energy conversion is a mature technology and is generally grouped into two types of configurations:

- Vertical-axis wind turbines, with the axis of rotation perpendicular to the ground.
- Horizontal-axis wind turbines, with the axis of rotation parallel to the ground.

Over 95 percent of turbines over 100 kW are horizontal-axis. Subsystems for either configuration typically include the following: a blade/rotor assembly to convert the energy in the wind to rotational shaft energy; a drive train, usually including a gearbox and a generator; a tower that supports the rotor and drive train; and other equipment, including controls, electrical cables, ground support equipment and interconnection equipment.

Wind turbine capacity is directly related to wind speed and equipment size, particularly to the rotor/blade diameter. The power generated by a turbine is proportional to the cube of the prevailing wind, that is, if the wind speed doubles, the available power will increase by a factor of eight. Because of this relationship, proper siting of turbines at locations with the highest possible average wind speeds is vital.

Appendix D includes NREL wind resource maps for Idaho, Oregon, Utah, Washington, and Wyoming with the locations of interest marked as provided by Owner.

4.2 Wind Performance

This Assessment includes 200 MW onshore wind generating facilities in Idaho, Oregon, Utah, Washington, and Wyoming service areas. BMcD relied on publicly available data and proprietary computational programs to complete the net capacity factor characterization. Generic project locations were selected within the area specified by Owner.

The Vestas V136-3.6 and GE3.8-137 wind turbine models were assumed for this analysis. The respective nameplate capacity, rotor diameter, and a hub height are provided in the Table 4-1. The maximum tip height of this package is under 500 feet, which means there are less likely to be conflicts with the Federal Aviation Administration (FAA) altitudes available for general aircraft. A generic power curve at standard atmospheric conditions for each of the sites was assumed for the V136-3.6 and GE3.8-137. Note that this turbine is intended only to be representative of a typical International Electrotechnical Commission wind

turbine. Because this analysis assumes generic site locations, the turbine selection is not optimized for a specific location or condition. Actual turbine selection requires further site-specific analysis.

Table 4-1: Summary of Wind Turbine Model Information

	Vestas V136-3.6	GE3.8-137
Name Plate Capacity, MW	3.6	3.6
Rotor Diameter, meters	136	137
Hub Height, meters	80	80

Using the NREL wind resource maps, the mean annual hub height wind speed at each potential project location was estimated and then extrapolated for the appropriate hub height to determine a representative wind speed. Using a Rayleigh distribution and power curve for the turbine technology described above, a gross annual capacity factor (GCF) was subsequently estimated for each site for both turbine types.

Annual losses for a wind energy facility were estimated at approximately 17 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 (NCF) for each potential site. Ideally, a utility-scale generation project should have an NCF of 30 percent or better. The NCF estimates for the PacifiCorp service areas are shown in the Summary Tables and represent an average of the two evaluated technologies.

4.3 Wind Cost Estimate

The wind energy cost estimate is shown in the Summary Tables. A typical cash flow for a wind project is included in Appendix F. Cost estimates assume an EPC project plus typical Owner's costs. Costs are based on a 200 MW plant with 3.6 MW turbines (56 total turbines) and 80-meter hub heights.

- Equipment and construction costs are broken down into subcategories per PacifiCorp's request. These breakouts represent the general scale of a 200 MW wind project but are not intended to indicate the expected scope for a specific site.
- The EPC scope includes a GSU transformer for interconnection at 230 kV.
- Land costs are excluded from the EPC and Owner's cost. For the 2018 Study, it is assumed that land is leased, and those costs are incorporated into the O&M estimate.

- Cost estimates also exclude escalation, interest during construction, financing fees, off-site infrastructure, and transmission.

4.4 Wind Energy O&M Estimates

O&M costs in the Summary Tables are derived from in-house information based on BMcD project experience and vendor information. Wind O&M costs are modeled as fixed O&M, including all typical operating expenses including:

- Labor costs
- Turbine O&M
- BOP O&M and other fixed costs (G&A, insurance, environmental costs, etc.)
- Property taxes
- Land lease payments

An allowance for capital replacement costs is not included within the annual O&M estimate in the Summary Table. A capital expenditures budget for a wind farm is generally a reserve that is funded over the life of the project that is dedicated to major component failures. An adequate capital expenditures budget is important for the long-term viability of the project, as major component failures are expected to occur, particularly as the facility ages.

If a capital replacement allowance is desired for planning purposes, Table 4-2 shows indicative budget expectations as a percentage of the total operating cost. As with operating expenses, however, these costs can vary with the type, size, or age of the facility, and project-specific considerations may justify deviations in the budgeted amounts.

Table 4-2: Summary of Indicative Capital Expenditures Budget by Year

Operational Years	Capital Expenditure Budget
0 – 2	None (warranty)
3 – 5	3% – 5%
6 – 10	5% – 10%
11 – 20	10% – 15%
21 – 30	15% – 20%
31 – 40	20% – 25%

4.5 Wind Energy Production Tax Credit

Tax credits such as the production tax credit (PTC) and investment tax credit (ITC) are not factored into the cost or O&M estimates in this Assessment, but an overview of the PTC is included below for reference.

To incentivize wind energy development, the PTC for wind was first included in the Energy Policy Act of 1992. It began as a $15/MWh production credit and has since been adjusted for inflation, currently worth approximately $24/MWh.

The PTC is awarded annually for the first 10 years of a wind facility's operation. Unlike the ITC that is common in the solar industry, there is no upfront incentive to offset capital costs. The PTC value is calculated by multiplying the $/MWh credit times the total energy sold during a given tax year. At the end of the tax year, the total value of the PTC is applied to reduce or eliminate taxes that the owners would normally owe. If the PTC value is greater than the annual tax bill, the excess credits can potentially go unused unless the owner has a suitable tax equity partner.

Since 1992, the changing PTC expiration/phaseout schedules have directly impacted market fluctuations, driving wind industry expansions and contractions. The PTC is currently available for projects that begin construction by the end of 2019, but with a phaseout schedule that began in 2017. Projects that started construction in 2015 and 2016 will receive the full value of the PTC, but those that start(ed) construction in later years will receive reduced credits:

- 2017: 80% of the full PTC value
- 2018: 60% of the full PTC value
- 2019: 40% of the full PTC value
- 2020: PTC Expires

To avoid receiving a reduction in the PTC, a "Safe Harbor" clause allowed for developers to avoid the reduction through an upfront investment in wind turbines by the end of 2016. The Safe Harbor clause allowed for wind projects to be considered as having begun construction by the end of the year if a minimum of 5% of the project's total capital cost was incurred before January 1st, 2017.

Many wind farms were planned for construction and operation when it was assumed they would receive 100% of the PTC. However, with the reduction in the PTC, some of these projects are no longer financially viable for developers to operate. This may result in renegotiated or canceled PPAs, or transfers to utilities for operation.

4.6 Wind Plus Storage

The wind plus storage options combine the wind technology discussed in section 4.0 with the lithium ion batteries described in section 7.0. The battery storage size is set at approximately 25% of the total nominal output of the base solar options, with options for two, four, and eight hours of storage duration. The storage system is assumed to be electrically coupled to the wind system on the AC side, meaning the storage system has its own inverter.

Capital costs are shown as add-on costs, broken out as project and owner's costs. These represent the additional capital above the wind base cost, intended to capture modest savings to account for shared system costs such as transformer(s) and switchgear. In addition, overlapping owner costs are eliminated or reduced. Finally, a line for O&M add-on costs is also included which can be added to the base wind O&M costs to determine overall facility O&M. As with the Li-Ion battery options, the co-located storage option assumes an operation profile of one cycle per day, which is used for calculating the O&M costs.

5.0 PUMPED HYDRO ENERGY STORAGE

5.1 General Description

Pumped-hydro Energy Storage (PHES) offers a way of storing off peak generation that can be dispatched during peak demand hours. This is accomplished using a reversable pump-turbine generator-motor where water is pumped from a lower reservoir to an upper reservoir using surplus off-peak electrical power. Energy is then recaptured by releasing the water back through the turbine to the lower reservoir during peak demand. To utilize PHES, locations need to be identified that have suitable geography near high-voltage transmission lines.

PHES provides the ability to optimize the system for satisfying monthly or even seasonal energy needs and PHES can provide spinning reserve capacity with its rapid ramp-up capability. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers. PHES is well suited for markets where there is a high spread in day-time and night-time energy costs, such that water can be pumped at a low cost and used to generate energy when costs are considerably higher.

PHES also has the ability to reduce cycling of existing generation plants. Additionally, PHES has a direct benefit to renewable resources as it is able to 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.

5.2 PHES Cost Estimate

The PHES cost estimate was based on information provided by developers with limited scope definition. We aligned the costs as closely as possible based on the information provided. The reason information from developers was used versus using a generic site for PHES is due to the significant importance of geographical location for this type of energy storage. The cost estimate is shown in the Summary Tables. PHES can see life cycle benefits as their high capital cost is offset by long lifespan of assets.

6.0 COMPRESSED AIR ENERGY STORAGE

6.1 General Description

Compressed air energy storage (CAES) offers a way of storing off peak generation that can be dispatched during peak demand hours. CAES is a proven, utility-scale energy storage technology that has been in operation globally for over 30 years. To utilize CAES, the project needs a suitable storage site, either above ground or below ground, and availability of transmission and fuel source. CAES facilities use off-peak electricity to power a compressor train that compresses air into an underground reservoir at approximately 850 psig. Energy is then recaptured by releasing the compressed air, heating it (typically) with natural gas firing, and generating power as the heated air travels through an expander.

This method of operation takes advantage of less expensive, off-peak power to charge the system to later be used for generation during periods of higher demand. CAES provides the ability to optimize the system for satisfying monthly, or even seasonal, energy needs and CAES can provide spinning reserve capacity with its rapid ramp-up capability. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers. Additionally, CAES has a direct benefit to renewable resources as it is able to 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.

There have been two commercial CAES plants built and operated in the world. The first plant began commercial operations in 1978 and was installed near Huntorf, Germany. This 290 MW facility included major equipment by Brown, Boveri, and Company (BBC). The second is located near McIntosh, Alabama and is currently owned and operated by PowerSouth (originally by Alabama Electric Cooperative). This 110 MW facility began commercial operations in 1991 and employs Dresser Rand (DR) equipment. BMcD served as the Owner's engineer for this project.

"Second generation" CAES designs have recently been developed, but do not have commercial operating experience. The compression-expansion portion of these designs is similar to "first generation" CAES designs. The designs differ in that a simple cycle gas turbine plant operates in parallel to the compression-expansion train and the exhaust is used in a recuperator instead of utilizing a combustor to preheat the stored air.

CAES is well suited for markets where there is a high spread in day-time and night-time energy costs, such that air can be compressed at a low cost and used to generate energy when costs are considerably higher.

6.2 CAES Cost Estimate

The CAES cost estimate is shown in the Summary Tables. It was developed using generic Siemens information that includes the power island, balance of plant and reservoir. Cost estimates assume an EPC project plus typical Owner's costs.

6.3 CAES Emissions Control

A Selective Catalytic Reduction (SCR) system is utilized in the CAES design along with demineralized water injection in the combustor to achieve NOx emissions of 2 parts per million, volumetric dry (ppmvd). A carbon monoxide (CO) catalyst is also used to control CO emissions to 2 ppmvd at the exit of the stack.

The use of an SCR and a CO catalyst requires additional site infrastructure. An SCR system injects ammonia into the exhaust gas to absorb and react with the exhaust gas to strip out NOx. This requires onsite ammonia storage and provisions for ammonia unloading and transfer.

7.0 BATTERY STORAGE TECHNOLOGY

This Assessment includes standalone battery options for both lithium ion (Li-Ion) and flow battery technologies. Li-Ion options included 1 MW output with 15-minute, 2-hour, 4-hour, and 8-hour storage capacities as well as a 15 MW option with 4-hours of storage. A 1 MW, 6-hour flow cell battery option was also included. Additionally, the solar and wind summary tables include optional costs for adding Li-Ion battery capacity of 25% of the nominal renewable output to the site with 2, 4, or 8-hours of storage.

7.1 General Description

Electrochemical energy storage systems utilize chemical reactions within a battery cell to facilitate electron flow, converting electrical energy to chemical energy when charging and generating an electric current when discharged. Electrochemical technology is continually developing as one of the leading energy storage and load following technologies due to its modularity, ease of installation and operation, and relative design maturity. Development of electrochemical batteries has shifted into three categories, commonly termed “flow,” “conventional,” and “high temperature” battery designs. Each battery type has unique features yielding specific advantages compared to one another.

7.1.1 Flow Batteries

Flow batteries utilize an electrode cell stack with externally stored electrolyte material. The flow battery is comprised of positive and negative electrode cell stacks separated by a selectively permeable ion exchange membrane, in which the charge-inducing chemical reaction occurs, and liquid electrolyte storage tanks, which hold the stored energy until discharge is required. Various control and pumped circulation systems complete the flow battery system in which the cells can be stacked in series to achieve the desired voltage difference.

The battery is charged as the liquid electrolytes are pumped through the electrode cell stacks, which serve only as a catalyst and transport medium to the ion-inducing chemical reaction. The excess positive ions at the anode are allowed through the ion-selective membrane to maintain electroneutrality at the cathode, which experiences a buildup of negative ions. The charged electrolyte solution is circulated back to storage tanks until the process is allowed to repeat in reverse for discharge as necessary.

In addition to external electrolyte storage, flow batteries differ from traditional batteries in that energy conversion occurs as a direct result of the reduction-oxidation reactions occurring in the electrolyte solution itself. The electrode is not a component of the electrochemical fuel and does not participate in the chemical reaction. Therefore, the electrodes are not subject to the same deterioration that depletes electrical performance of traditional batteries, resulting in high cycling life of the flow battery. Flow

batteries are also scalable such that energy storage capacity is determined by the size of the electrolyte storage tanks, allowing the system to approach its theoretical energy density. Flow batteries are typically less capital intensive than some conventional batteries but require additional installation and operation costs associated with balance of plant equipment.

7.1.2 Conventional Batteries

A conventional battery contains a cathodic and an anodic electrode and an electrolyte sealed within a cell container that can be connected in series to increase overall facility storage and output. During charging, the electrolyte is ionized such that when discharged, a reduction-oxidation reaction occurs, which forces electrons to migrate from the anode to the cathode thereby generating electric current. Batteries are designated by the electrochemicals utilized within the cell; the most popular conventional batteries are lead acid and Li-Ion type batteries.

Lead acid batteries are the most mature and commercially accessible battery technology, as their design has undergone considerable development since conceptualized in the late 1800s. The Department of Energy (DOE) estimates there is approximately 110 MW of lead acid battery storage currently installed worldwide. Although lead acid batteries require relatively low capital cost, this technology also has inherently high maintenance costs and handling issues associated with toxicity, as well as low energy density (yields higher land and civil work requirements). Lead acid batteries also have a relatively short life cycle at 5 to 10 years, especially when used in high cycling applications.

Li-Ion batteries contain graphite and metal-oxide electrodes and lithium ions dissolved within an organic electrolyte. The movement of lithium ions during cell charge and discharge generates current. Li-Ion technology has seen a resurgence of development in recent years due to its high energy density, low self-discharge, and cycling tolerance. Many Li-Ion manufacturers currently offer 15-year warranties or performance guarantees. Consequently, Li- Ion has gained traction in several markets including the utility and automotive industries.

Li-Ion battery prices are trending downward, and continued development and investment by manufacturers are expected to further reduce production costs. While there is still a wide range of project cost expectations due to market uncertainty, Li-Ion batteries are anticipated to expand their reach in the utility market sector.

7.1.3 High Temperature Batteries

High temperature batteries operate similarly to conventional batteries, but they utilize molten salt electrodes and carry the added advantage that high temperature operation can yield heat for other

applications simultaneously. The technology is considered mature with ongoing commercial development at the grid level. The most popular and technically developed high temperature option is the Sodium Sulfur (NaS) battery. Japan-based NGK Insulators, the largest NaS battery manufacturer, installed a 4 MW system in Presidio, Texas in 2010 following operation of systems totaling more than 160 MW since the project's inception in the 1980s.

The NaS battery is typically a hermetically sealed cell that consists of a molten sulfur electrolyte at the cathode and molten sodium electrolyte at the anode, separated by a Beta-alumina ceramic membrane and enclosed in an aluminum casing. The membrane is selectively permeable only to positive sodium ions, which are created from the oxidation of sodium metal and pass through to combine with sulfur resulting in the formation of sodium polysulfides. As power is supplied to the battery in charging, the sodium ions are dissociated from the polysulfides and forced back through the membrane to re-form elemental sodium. The melting points of sodium and sulfur are approximately 98ºC and 113ºC, respectively. To maintain the electrolytes in liquid form and for optimal performance, the NaS battery systems are typically operated and stored at around 300ºC, which results in a higher self-discharge rate of 14 percent to 18 percent. For this reason, these systems are usually designed for use in high-cycling applications and longer discharge durations.

NaS systems are expected to have an operable life of around 15 years and are one of the most developed chemical energy storage technologies. However, unlike other battery types, costs of NaS systems have historically held, making other options more commercially viable at present.

7.2 Battery Emissions Controls

No emission controls are currently required for battery storage facilities. However, Li-Ion batteries can release large amounts of gas during a fire event. While not currently an issue, there is potential for increased scrutiny as more battery systems are placed into service.

7.3 Battery Storage Performance

This assessment includes performance for multiple Li-Ion options as well as one flow battery option. Li-Ion systems can respond in seconds and exhibit excellent ramp rates and round-trip cycle efficiencies. Because the technology is rapidly advancing, there is uncertainty regarding estimates for cycle life, and these estimates vary greatly depending on the application and depth of discharge. The systems in this Assessment are assumed to perform one full cycle per day, and capacity factors are based on the duration of full discharge for 365 days. OEMs typically have battery products that are designed to suit different use-cases such as high power or high energy applications. The power to energy ratio is commonly shown

as a C-ratio (for example, a 1MW / 4 MWh system would use a 0.25C battery product). However, the 8-hour battery option is based on a 0.25C system that is sized for twice the power and discharged for eight hours instead of four. While the technology continues to advance, commercially available, high energy batteries for utility scale applications are generally 0.25C and above.

Flow batteries are a maturing technology that is well suited for longer discharge durations (>4 hours, for example). Flow batteries can provide multiple use cases from the same system and they are not expected to exhibit performance degradation like lithium ion technologies. However, they typically have lower round trip efficiency than Li-Ion batteries. Storage durations are currently limited to commercial offerings from select vendors but are expected to broaden over the next several years. Performance guarantees of 20 years are expected with successful commercialization, but there is not necessarily a technical reason that original equipment manufacturer (OEM) and/or balance of plant (BOP) designs could not accommodate 30+ year life.

7.4 Regulatory Trends

Two (2) Federal Energy Regulatory Commission (FERC) Orders released in 2018 are expected to provide clarity on the role of storage in wholesale markets, and potentially drive continued growth. FERC Order 841 requires RTOs and ISOs to develop clear rules regulating the participation of energy storage systems in wholesale energy, capacity, and ancillary services markets. Prior to the final release of FERC 841, the California Public Utilities Commission introduced 11 rules to determine how multi-use storage products participate in California Independent System Operator (CAISO). FERC Order 842 addresses requirements for some generating facilities to provide frequency response, including accommodations for storage technologies. In addition, the Internal Revenue Service (IRS) is considering new guidance for the ITC that will impact projects combining storage with renewables.

7.5 Battery Storage Cost Estimate

The estimated costs of the Li-Ion and flow battery systems are included in the Summary Tables, based on BMcD experience and vendor correspondence. The key cost elements of a Li-Ion battery system are the inverter, the battery cells, the interconnection, and the installation. The capital costs reflect recent trends for overbuild capacity to account for short term degradation. The battery enclosures include space for future augmentation, but the costs associated with augmentation are covered in the O&M costs. It is assumed that land is available at an existing PacifiCorp facility and is therefore excluded from the cost estimate. These options assume the battery interconnects at medium voltage.

Flow battery estimates for the 1 MW option are based on zinc-bromine technology with a 6-hour storage duration. This is a modular design in which the OEM scope includes the stack, electrolyte storage, and associated pumps and controls in a factory assembled package. The EPC scope includes the inverters, switchgear, MV transformer, and installation.

7.6 Battery Storage O&M Cost Estimate

O&M estimates for the Li-Ion and flow battery systems are shown in the Summary Tables, based on BMcD experience and recent market trends. The battery storage system is assumed to be operated remotely.

The technical life of a Li-Ion battery project is expected to be 15 years, but battery performance degrades over time, and this degradation is considered in the system design. Systems can be "overbuilt" by including additional capacity in the initial installation, and they can also be designed for future augmentation. Augmentation means that designs account for the addition of future capacity to maintain guaranteed performance.

Overbuild and augmentation philosophies can vary between projects. Because battery costs are expected to continue falling, many installers/integrators are aiming for lower initial overbuild percentages to reduce initial capital costs, which means guarantees and service contracts will require more future augmentation to maintain capacity. Because costs should be lower in the future, the project economics may favor this approach. This assessment assumes minimal overbuild beyond system efficiency losses, and the O&M estimates include allowances for augmentation.

Battery storage O&M costs are modeled to represent the fixed and variable portions of performance guarantees and augmentation from recent BMcD project experience. The fixed O&M cost for the Li-Ion systems include a nominal fixed cost to administer and maintain the O&M contract with an OEM/integrator, plus an allowance for calendar degradation fees. Calendar degradation represents performance degradation and subsequent augmentation expected to occur regardless of the system's operation profile, even if the batteries sit unused. Because calendar degradation is not tied to system operation or output, it is modeled as part of the fixed O&M.

Variable O&M estimates for Li-ion options account for cycling degradation fees. Cycling the batteries increases performance degradation, so the performance guarantees provided by the OEM and/or integrator are commonly modeled to account for augmentation based on the expected operating profile. The variable O&M estimates in this assessment are based on an operation profile of one charge/discharge cycle per day and may not be valid for increased cycling.

Flow battery O&M costs are modeled around an annual service contract from the OEM or a factory trained third party. Costs are based on correspondence with manufacturers and are subject to change as the technology achieves greater commercialization and utilization in the utility sector. Unlike Li-Ion technologies, flow batteries generally do not exhibit calendar or cycle degradation, so there is not a variable O&M component per cycle. There is mechanical equipment that requires service based on an OEM recommended schedule, which is modeled as a levelized annual cost for the life of the system.

8.0 CONCLUSIONS

This Renewable Energy Resource Technology Assessment provides information to support PacifiCorp's power supply planning efforts. Information provided in this Assessment is screening level in nature and is intended to highlight indicative, differential costs associated with each technology. BMcD recommends that PacifiCorp use this information to update production cost models for comparison of renewable resource alternatives and their applicability to future resource plans. PacifiCorp should pursue additional engineering studies to define project scope, budget, and timeline for technologies of interest.

Renewable options include PV and wind systems. PV is a proven technology for daytime peaking power and a viable option to pursue renewable goals. PV capital costs have steadily declined for years, but recent import tariffs on PV panels and foreign steel may impact market trends. Wind energy generation is a proven technology and turbine costs dropped considerably over the past few years.

Utility-scale battery storage systems are being installed in varied applications from frequency response to arbitrage, and recent cost reduction trends are expected to continue. Li-Ion technology is achieving the greatest market penetration, aided in large part by its dominance in the automotive industry, but other technologies like flow batteries should be monitored, as well.

PacifiCorp's region has several geological sites that can support large scale storage options including PHES and CAES. This gives PacifiCorp flexibility in terms of energy storage. Smaller applications will be much better suited for battery technologies, but if a larger need is identified PHES or CAES could provide excellent larger scale alternatives. Both of these technologies benefit from economies of scale in regard to their total kWh of storage, allowing them to decrease the overall $/kWh project costs.

APPENDIX A – SUMMARY TABLES

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
ENERGY STORAGE

PROJECT TYPE	**Pumped Hydro**						**Li-Ion Battery**					**Flow Battery**
BASE PLANT DESCRIPTION	**Swan Lake**	**Goldendale**	**Seminoe**	**Flat Canyon**	**Idaho PS 1**							
Nominal Output	400 MW 3,800 MWh	1200 MW 16,800 MWh	700 MW 7,000 MWh	300 MW 1,800 MWh	360 MW 2,880 MWh	320 MW 15,360 MWh	1 MW 0.25 MWh	1 MW 2 MWh	1 MW 4 MWh	1 MW 8 MWh	15 MW 60 MWH	1 MW 6 MWh
Capacity Factor (%)	17%	17%	17%	17%	17%	20%	2%	8%	17%	33%	17%	25%
Startup Time (Cold Start), minutes	1.5	1.5	1.5	1.5	1.5	10	N/A	N/A	N/A	N/A	N/A	N/A
Full Pumping to Full Gen, minutes	4	4	4	4	4	7	N/A	N/A	N/A	N/A	N/A	N/A
Transition Time from Charging to Discharging, minutes (note 10)	6	6	6	6	6	3	<1 sec in active mode	<1 sec in active mode	<1 sec in active mode	<1 sec in active mode	<1 sec in active mode	<1 sec in active mode
Availability Factor, %	90%	90%	90%	90%	90%	96%	97%	97%	97%	97%	97%	95%
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Commercial
Life Cycle, yrs	60	60	60	60	60	30+	15	15	15	15	15	20
Permitting & Construction Schedule, year (note 1)	6	10	8	6	12	3	1	1	1	1	1	2
ESTIMATED PERFORMANCE												
Base Load Performance @ (Annual Average)												
Net Plant Output, kW	393,300	1,200,000	700,000	300,000	360,000	320,000	1,000	1,000	1,000	1,000	15,000	1,000
Total Plant Storage, kWh (note 4)	3,736,350	16,800,000	7,000,000	1,800,000	2,880,000	15,360,000	250	2,000	4,000	8,000	60,000	6,000
Time for Full Discharge, hours	9.5	14	10	6	8	48	0.25	2	4	8	4	6
Time for Full Charge, hrs	9.5	14	12	7.5	8	192	0.3	2.3	4.6	9.2	4.6	8
Heat Rate (HHV), Btu/kWh	N/A	N/A	N/A	N/A	N/A	4,230	N/A	N/A	N/A	N/A	N/A	N/A
Round-Trip Efficiency (%) (note 5)	79%	79%	79%	79%	79%	55%	88%	88%	88%	88%	88%	65%
ESTIMATED CAPITAL AND O&M COSTS (Note 11)												
EPC Project Capital Costs, 2018 MM$ (w/o Owner's Costs)	**$814**	**$2,146**	**$1,352**	**$545**	**$635**	**$384**	**$1.0**	**$1.8**	**$2.5**	**$3.8**	**$21.8**	**$2.8**
Owner's Costs, 2018 MM$	**$163**	**$429**	**$270**	**$109**	**$127**	**$77**	**$0.4**	**$0.6**	**$0.6**	**$0.8**	**$2.1**	**$0.7**
Owner's Project Development	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.1	$0.2	$0.1
Owner's Engineer	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Project Management	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.1	$0.2	$0.1
Owner's Legal Costs	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Permitting and Licensing Fees	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.1	$0.2	$0.1
Generation Switchyard (note 6)	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	N/A	N/A	N/A	N/A	N/A	N/A
Transmission to Interconnection Point	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	N/A	N/A	N/A	N/A	N/A	N/A
Training/Testing	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Land	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located
Builders Risk Insurance (0.45% of Project Cost)	Included	Included	Included	Included	Included	Included	$0.00	$0.01	$0.01	$0.02	$0.1	$0.01
Owner's Contingency	Included	Included	Included	Included	Included	Included	$0.1	$0.1	$0.1	$0.2	$1.1	$0.2
Total Screening Level Project Costs, 2018 MM$	**$977**	**$2,575**	**$1,622**	**$654**	**$762**	**$461**	**$1.4**	**$2.4**	**$3.1**	**$4.7**	**$24.0**	**$3.5**
EPC Project Costs, 2018 $/kW	**$2,070**	**$1,790**	**$1,930**	**$1,820**	**$1,760**	**$1,200**	**$990**	**$1,780**	**$2,470**	**$3,850**	**$1,450**	**$2,790**
EPC Project Costs, 2018 $/kWh	**$220**	**$130**	**$190**	**$300**	**$220**	**$30**	**$3,940**	**$890**	**$620**	**$480**	**$360**	**$460**
Total Screening Level Project Costs, 2018 $/kW	**$2,480**	**$2,150**	**$2,320**	**$2,180**	**$2,120**	**$1,440**	**$1,420**	**$2,380**	**$3,110**	**$4,670**	**$1,600**	**$3,520**
Total Screening Level Project Costs, 2018 $/kWh	**$260**	**$150**	**$230**	**$360**	**$260**	**$30**	**$5,670**	**$1,190**	**$780**	**$580**	**$400**	**$590**
O&M Cost, 2018 MM$/yr	$7	$15	$12	$5	$6	$2	$0.009	$0.035	$0.056	$0.094	$0.489	$0.032
Fixed O&M Cost, 2018 MM$/yr							$0.008	$0.024	$0.035	$0.052	$0.172	$0.032
Variable O&M Cost, 2018 MM$/yr							$0.001	$0.011	$0.021	$0.042	$0.317	Incl. in FOM

Notes

Note 1. Permitting & Construction Schedule is based on earliest COD date for some of the pumped hydro options
Note 2. Swan Lake Capital Cost and Fixed O&M Cost is middle of range given by Rye Development and National Grid Ventures
Note 3. Owner's cost is assumed to be 20% of capital costs for pumped hydro and CAES options. Based on information provided by developers and includes items listed above.
Note 4. CAES storage is based on full charge. Typical operation is to not fully discharge, but rather to discharge only a portion of the capacity to maintain cavern pressure.
Note 5. Round trip efficiency for CAES is based on the electric energy input to compress air plus the energy in the gas input compared to the electrical output.
Note 6. Battery options (Li-Ion and Flow) assumes interconnection at distribution voltage and therefore excludes GSU and switchyard.
Note 7. Battery O&M assumes the site is remotely controlled. Capital costs assume the system is slightly oversized initially to accommodate normal degradation at the start of the project life, and then degradation supplement cost throughout the project life. O&M accounts for the parasitic power draw of the system, including HVAC and efficiency losses.

Note 8. Pumped Hydro O&M excludes major maintenance cost items, like generator rewinds, that are viewed as end of life repairs to extend the intended life of the asset.
Note 9. Battery capacity factor and annual O&M is based on one full cycle per day.
Note 10. CAES storage supports simultaneous operation of compression and expansion.
Note 11. EPC and Owner's Cost estimates exclude AFUDC, Sales Tax, Insurance and Property Tax During Construction

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
SOLAR GENERATION

PROJECT TYPE	**Solar Photovoltaic - Single Axis Tracking**														
PROJECT LOCATION	**Idaho Falls, ID**			**Lakeview, OR**			**Milford, UT**			**Rock Springs, WY**			**Yakima, WA**		
BASE PLANT DESCRIPTION	**5 MW**	**50 MW**	**200 MW**	**5 MW**	**50 MW**	**200 MW**	**5 MW**	**50 MW**	**200 MW**	**5 MW**	**50 MW**	**200 MW**	**5 MW**	**50 MW**	**200 MW**
Nominal Output, MW	5	50	200	5	50	200	5	50	200	5	50	200	5	50	200
Annualized Energy Production, MWh (Yr 1)	11,597	122,929	491,714	12,292	130,139	520,556	13,451	142,375	569,501	12,355	131,702	526,808	10,609	114,065	456,258
AC Capacity Factor at POI (%) (Note 1)	26.5%	28.1%	28.1%	28.1%	29.7%	29.7%	30.7%	32.5%	32.5%	28.2%	30.1%	30.1%	24.2%	26.0%	26.0%
Availability Factor, % (Note 2)	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
Assumed Land Use, Acres	40	400	1600	40	400	1600	40	400	1600	40	400	1600	40	400	1600
PV Inverter Loading Ratio (DC/AC)	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32	1.32
PV POI Ratio (DC/AC)	1.32	1.46	1.46	1.32	1.46	1.46	1.32	1.46	1.46	1.32	1.46	1.46	1.32	1.46	1.46
PV Degradation, %/yr (Note 3)	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
ESTIMATED PERFORMANCE															
Base Load Performance @ (Annual Average) Net Plant Output, kW	5,000	50,000	200,000	5,000	50,000	200,000	5,000	50,000	200,000	5,000	50,000	200,000	5,000	50,000	200,000
ESTIMATED CAPITAL AND O&M COSTS (Note 7)															
EPC Project Capital Costs, 2018 MM$ (w/o Owner's Costs)	**$7**	**$71**	**$277**	**$8**	**$76**	**$297**	**$7**	**$71**	**$276**	**$7**	**$70**	**$275**	**$8**	**$76**	**$296**
Modules	$2	$27	$107	$2	$27	$107	$2	$27	$107	$2	$27	$107	$2	$27	$107
Racking w/ Piles	$1	$9	$35	$1	$9	$35	$1	$9	$35	$1	$9	$35	$1	$9	$35
Inverter & MV Transformer	$0	$3	$13	$0	$3	$13	$0	$3	$13	$0	$3	$13	$0	$3	$13
Labor, Materials, and BOP Equiment	$2	$25	$102	$3	$30	$121	$2	$25	$101	$2	$25	$100	$3	$30	$120
Project Indirects, Fee, and Contingency	$1	$7	$20	$1	$7	$21	$1	$7	$20	$1	$7	$20	$1	$7	$21
Owner's Costs, 2018 MM$	**$1**	**$54**	**$67**	**$2**	**$54**	**$68**	**$1**	**$54**	**$67**	**$1**	**$54**	**$67**	**$2**	**$54**	**$68**
Owner's Project Development	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Owner's Project Management	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Legal Costs	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Permitting and Licensing Fees	$0.4	$0.5	$0.6	$0.4	$0.5	$0.6	$0.4	$0.5	$0.6	$0.4	$0.5	$0.6	$0.4	$0.5	$0.6
Generation Switchyard (Note 5)	$0.0	$2.0	$2.0	$0.0	$2.0	$2.0	$0.0	$2.0	$2.0	$0.0	$2.0	$2.0	$0.0	$2.0	$2.0
Transmission Interconnection (Note 8)	$0.0	$34.5	$34.5	$0.0	$34.5	$34.5	$0.0	$34.5	$34.5	$0.0	$34.5	$34.5	$0.0	$34.5	$34.5
Transmission Interconnection Application and Upgrades (Note 9)	$0.0	$9.8	$9.8	$0.0	$9.8	$9.8	$0.0	$9.8	$9.8	$0.0	$9.8	$9.8	$0.0	$9.8	$9.8
Land (Note 4)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Operating Spare Parts	$0.0	$0.4	$1.6	$0.0	$0.4	$1.6	$0.0	$0.4	$1.6	$0.0	$0.4	$1.6	$0.0	$0.4	$1.6
Builders Risk Insurance (0.45% of Project Cost)	$0.0	$0.3	$1.2	$0.0	$0.3	$1.3	$0.0	$0.3	$1.2	$0.0	$0.3	$1.2	$0.0	$0.3	$1.3
Owner's Contingency	$0.4	$5.9	$16.4	$0.4	$6.2	$17.4	$0.4	$5.9	$16.3	$0.4	$5.9	$16.3	$0.4	$6.2	$17.3
Total Screening Level Project Costs, 2018 MM$	**$9**	**$125**	**$343**	**$9**	**$130**	**$365**	**$9**	**$125**	**$343**	**$9**	**$124**	**$342**	**$9**	**$130**	**$364**
EPC Project Costs, 2018 $/kW	**$1,430**	**$1,420**	**$1,380**	**$1,520**	**$1,520**	**$1,490**	**$1,420**	**$1,410**	**$1,380**	**$1,420**	**$1,410**	**$1,380**	**$1,510**	**$1,510**	**$1,480**
Total Screening Level Project Costs, 2018 $/kW	**$1,720**	**$2,500**	**$1,720**	**$1,820**	**$2,600**	**$1,820**	**$1,720**	**$2,490**	**$1,710**	**$1,710**	**$2,490**	**$1,710**	**$1,810**	**$2,600**	**$1,820**
O&M Cost, 2018 MM$/yr	$0.2	$2.0	$8.1	$0.2	$2.0	$8.1	$0.2	$2.0	$8.1	$0.2	$2.0	$8.1	$0.2	$2.0	$8.1
O&M Cost, 2018 $/kW-yr	$42.20	$40.40	$40.40	$42.20	$40.40	$40.40	$42.20	$40.40	$40.40	$42.20	$40.40	$40.40	$42.20	$40.40	$40.40
Co-Located Energy Storage - 2 hr Capacity	1 MW | 2 MWh	10 MW | 20 MWh	50 MW | 100 MWh	1 MW | 2 MWh	10 MW | 20 MWh	50 MW | 100 MWh	1 MW | 2 MWh	10 MW | 20 MWh	50 MW | 100 MWh	1 MW | 2 MWh	10 MW | 20 MWh	50 MW | 100 MWh	1 MW | 2 MWh	10 MW | 20 MWh	50 MW | 100 MWh
Add-On Costs															
Capital Costs, 2018 MM$	$1.7	$10.8	$33.7	$1.9	$11.6	$36.3	$1.7	$10.8	$33.7	$1.7	$10.8	$33.7	$1.9	$11.6	$36.3
Owner's Costs, 2018 MM$	$0.5	$1.2	$2.7	$0.5	$1.3	$2.8	$0.5	$1.2	$2.7	$0.5	$1.2	$2.7	$0.5	$1.3	$2.8
Incremental O&M Cost, 2018 MM$/Yr	$0.03	$0.19	$0.77	$0.03	$0.19	$0.77	$0.03	$0.19	$0.77	$0.0	$0.19	$0.77	$0.03	$0.19	$0.77
Co-Located Energy Storage - 4 hr Capacity	1 MW | 4 MWh	10 MW | 40 MWh	50 MW | 200 MWh	1 MW | 4 MWh	10 MW | 40 MWh	50 MW | 200 MWh	1 MW | 4 MWh	10 MW | 40 MWh	50 MW | 200 MWh	1 MW | 4 MWh	10 MW | 40 MWh	50 MW | 200 MWh	1 MW | 4 MWh	10 MW | 40 MWh	50 MW | 200 MWh
Add-On Costs															
Capital Costs, 2018 MM$	$2.4	$16.3	$58.7	$2.6	$17.6	$63.3	$2.4	$16.3	$58.7	$2.4	$16.3	$58.7	$2.6	$17.6	$63.3
Owner's Costs, 2018 MM$	$0.6	$1.5	$4.0	$0.6	$1.6	$4.28	$0.4	$1.5	$4.0	$0.4	$1.5	$4.0	$0.4	$1.6	$4.3
Incremental O&M Cost, 2018 MM$/Yr	$0.06	$0.35	$1.43	$0.06	$0.35	$1.43	$0.06	$0.35	$1.43	$0.0	$0.35	$1.43	$0.06	$0.35	$1.43
Co-Located Energy Storage - 8 hr Capacity	1 MW | 8 MWh	10 MW | 80 MWh	50 MW | 400 MWh	1 MW | 8 MWh	10 MW | 80 MWh	50 MW | 400 MWh	1 MW | 8 MWh	10 MW | 80 MWh	50 MW | 400 MWh	1 MW | 8 MWh	10 MW | 80 MWh	50 MW | 400 MWh	1 MW | 8 MWh	10 MW | 80 MWh	50 MW | 400 MWh
Add-On Costs															
Capital Costs, 2018 MM$	$3.8	$26.6	$107.8	$4.1	$28.6	$116.2	$3.8	$26.6	$107.8	$3.8	$26.6	$107.8	$4.1	$28.7	$116.2
Owner's Costs, 2018 MM$	$0.6	$2.1	$6.7	$0.7	$2.2	$7.2	$0.8	$2.1	$6.7	$0.8	$2.1	$6.7	$0.8	$2.2	$7.2
Incremental O&M Cost, 2018 MM$/Yr	$0.09	$0.63	$2.72	$0.09	$0.63	$2.72	$0.09	$0.63	$2.72	$0.0	$0.63	$2.72	$0.09	$0.63	$2.72

Notes

Note 1. Solar capacity factor accounts for typical losses. 50 and 200 MW options have AC capacity overbuilt for high voltage losses. Additional inverters and economic efficiencies for overbuilding for larger sizes results in the capacity factor different between the two larger sizes and the 5 MW installation.
Note 2. Availability estimates are based on vendor correspondence and industry publications.
Note 3. PV degradation based on typical warranty information for polycrystalline products. Assuming factory recommended maintenance is performed, PV performance is estimated to degrade ~2% in the first year and 0.5% each following year. The first year 2% degradation is accounted for in the PVSyst model output for year 1.
Note 4. PV projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Assumes eight acres per MW for tracking.
Note 5. 5 MW options assume interconnection at medium voltage. 50 & 200 MW options assume high voltage connection with switchyard.
Note 6. Oregon and Washington cost estimates assume union labor.
Note 7. EPC and Owner's Cost estimates exclude AFUDC, Sales Tax, Insurance and Property Tax During Construction
Note 8. Transmission interconnect allowance assumes 15 miles of transmission line at high voltage for 50 & 200 MW options. Land costs are excluded.
Note 9. Transmission interconnect application costs and upgrade costs are representative only. These costs can vary greatly depending on the site location and existing infrastructure.

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	**200 MW**	**200 MW**	**200 MW**	**200 MW**	**200 MW**
Nominal Output, MW	200	200	200	200	200
Number of Turbines	56 x 3.6 MW	56 x 3.6 MW	56 x 3.6 MW	56 x 3.6 MW	56 x 3.6 MW
Capacity Factor (Note 1)	37.1%	37.1%	29.5%	43.6%	37.1%
Availability Factor, % (Note 2)	95%	95%	95%	95%	95%
Assumed Land Use, Acres	56	56	56	56	56
Technology Rating	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2.5	2.5	2.5	2.5	2.5
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 (Note 6)					
Project Capital Costs, 2018 MM$ (w/o Owner's Costs)	**$228**	**$229**	**$228**	**$228**	**$228**
Wind Turbine Generators	$160	$160	$160	$160	$161
Roads	$5	$5	$5	$5	$5
O&M Building	$2	$2	$2	$2	$2
Collection System	$8	$8	$8	$8	$8
Other BOP, Materials, Labor, Indirects	$53	$54	$53	$53	$53
Owner's Costs, 2018 MM$	**$103**	**$103**	**$103**	**$103**	**$103**
Project Development (Note 3)	$22.8	$22.8	$22.8	$22.8	$22.8
Wind Resource Assessment	$1.0	$1.0	$1.0	$1.0	$1.0
Land Control	$2.4	$2.4	$2.4	$2.4	$2.4
Permitting and Licensing Fees	$3.2	$3.2	$3.2	$3.2	$3.2
Generation Switchyard	$2.0	$2.0	$2.0	$2.0	$2.0
Transmission Interconnection (Note 7)	$34.5	$34.5	$34.5	$34.5	$34.5
Transmission Interconnection Application and Upgrades (Note 8)	$9.8	$9.8	$9.8	$9.8	$9.8
Land (Note 4)	$0.0	$0.0	$0.0	$0.0	$0.0
Operating Spare Parts	Included in O&M	Included in O&M	Included in O&M	Included in O&M	Included in O&M
Temporary facilities and Construction Utilities	$12.0	$12.0	$12.0	$12.0	$12.0
Builders Risk Insurance (0.45% of Project Cost)	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs	Included in Project Costs
Owner's Contingency	$15.8	$15.8	$15.8	$15.8	$15.8
Total Screening Level Project Costs, 2018 MM$	**$332**	**$333**	**$332**	**$332**	**$332**
EPC Project Costs, 2018 $/kW	**$1,140**	**$1,150**	**$1,140**	**$1,140**	**$1,140**
Total Screening Level Project Costs, 2018 $/kW	**$1,660**	**$1,660**	**$1,660**	**$1,660**	**$1,660**
O&M Cost, 2018 MM$/yr	$10.2	$10.2	$9.8	$9.2	$9.8
O&M Cost, 2018 $/kW-yr	$51.0	$51.0	$49.0	$46.0	$49.0
Co-Located Energy Storage - 2 hr Capacity	50 MW | 100 MWh	50 MW | 100 MWh	50 MW | 100 MWh	50 MW | 100 MWh	50 MW | 100 MWh
Add-On Costs					
Capital Costs, 2018 MM$	$33.7	$35.9	$33.7	$33.7	$35.8
Owner's Costs, 2018 MM$	$2.7	$2.8	$2.7	$2.7	$2.8
Incremental O&M Cost, 2018 MM$/Yr	$0.77	$0.77	$0.77	$0.77	$0.77
Co-Located Energy Storage - 4 hr Capacity	50 MW | 200 MWh	50 MW | 200 MWh	50 MW | 200 MWh	50 MW | 200 MWh	50 MW | 200 MWh
Add-On Costs					
Capital Costs, 2018 MM$	$58.7	$62.6	$58.7	$58.7	$62.5
Owner's Costs, 2018 MM$	$4.0	$4.3	$4.0	$4.0	$4.3
Incremental O&M Cost, 2018 MM$/Yr	$1.4	$1.4	$1.4	$1.4	$1.4
Co-Located Energy Storage - 8 hr Capacity	50 MW | 400 MWh	50 MW | 400 MWh	50 MW | 400 MWh	50 MW | 400 MWh	50 MW | 400 MWh
Add-On Costs					
Capital Costs, 2018 MM$	$107.8	$114.9	$107.8	$107.8	$114.8
Owner's Costs, 2018 MM$	$6.7	$7.2	$6.7	$6.7	$7.2
Incremental O&M Cost, 2018 MM$/Yr	$2.7	$2.7	$2.7	$2.7	$2.7

Notes

Note 1. Wind capacity factor based on NREL 80 meter wind speed maps.
Note 2. Availability estimates are based on vendor correspondence and industry publications.
Note 3. Development costs include legal costs, developer costs prior to COD, Owner project management, engineering, and interconnect studies.
Note 4. Wind projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Assumes one acre per turbine.
Note 5. Oregon and Washington cost estimates assume union labor.
Note 6. EPC and Owner's Cost estimates exclude AFUDC, Sales Tax, Insurance and Property Tax During Construction
Note 7. Transmission interconnect allowance assumes 15 miles of transmission line at high voltage. Land costs are excluded.
Note 8. Transmission interconnect application and upgrade costs are representative only. These costs can vary greatly depending on the site location and existing infrastructure.

APPENDIX B – SOLAR PVSYST MODEL OUTPUT (5MW)

Grid-Connected System: Simulation parameters

Project : **PC18-Grid-IdahoFallsID-SAT**

Geographical Site	**Idaho Falls Fanning Field**		Country	**USA**
Situation	Latitude	43.5°N	Longitude	112.1°W
Time defined as	Legal Time	Time zone UT-7	Altitude	1441 m
	Albedo	0.20		
Meteo data:	**Idaho Falls Fanning Field**	TMY - NREL: TMY3 hourly DB (1991-2005)		

Simulation variant : **PC18_IdahoFalls_Rev3**

Simulation date 31/08/18 13h50

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	5.50 m	Collector width	1.98 m
Inactive band	Left	0.20 m	Right	0.20 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Free Horizon			
Near Shadings	Linear shadings			

PV Array Characteristics

PV module	Si-poly	Model	**CS3U-340P 1500V**		
		Manufacturer	Canadian Solar Inc.		
		Orientation	#1	Tilt/Azimuth	30°/0°
Number of PV modules		In series	26 modules	In parallel	738 strings
Total number of PV modules		Nb. modules	19188	Unit Nom. Power	340 Wp
Array global power		Nominal (STC)	**6524 kWp**	At operating cond.	5890 kWp (50°C)
Array operating characteristics (50°C)		U mpp	895 V	I mpp	6580 A
Total area		Module area	**38069 m²**	Cell area	33931 m²
Inverter		Model	**SMA SC2500 EV Prelim!**		
		Manufacturer	SMA		
Characteristics		Operating Voltage	850-1425 V	Unit Nom. Power	2500 kWac
Inverter pack		Nb. of inverters	2 units	Total Power	5000 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.5%	2.5%	2.5%	2.5%	2.0%	2.0%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.3 mOhm	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP

Grid-Connected System: Simulation parameters (continued)

Incidence effect, user defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.00	1.00	1.00	0.99	0.99	0.97	0.92	0.76	0.00

System loss factors

Wiring Ohmic Loss Wires 0 m 3x0.0 mm² Loss Fraction 0.0 % at STC

User's needs : Unlimited load (grid)

Grid-Connected System: Main results

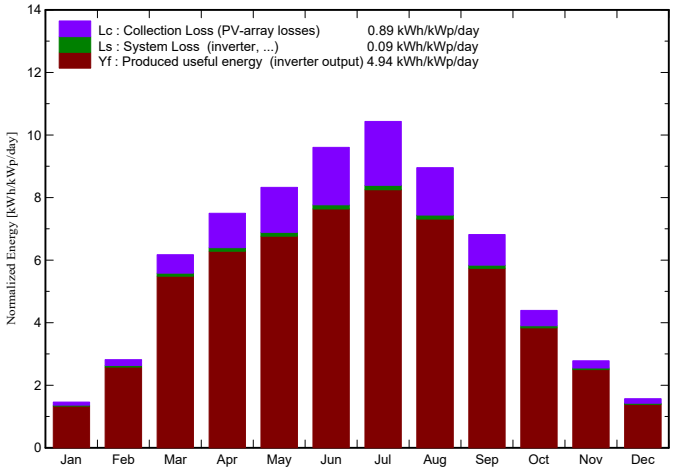
Project : **PC18-Grid-IdahoFallsID-SAT**

Simulation variant : **PC18_IdahoFalls_Rev3**

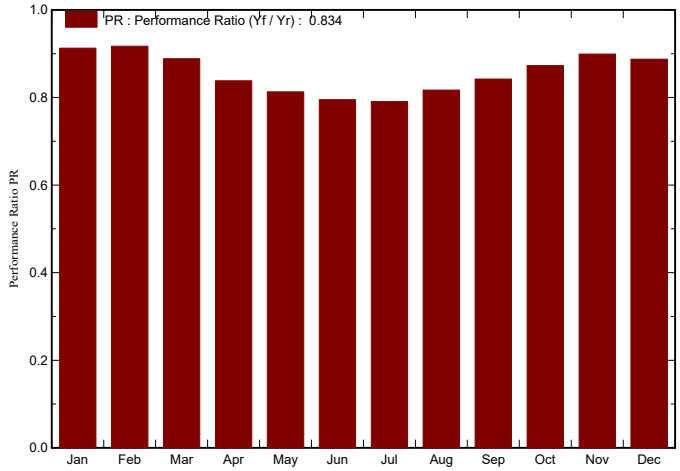
Main system parameters	System type	**Grid-Connected**		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results				
System Production	**Produced Energy**	**11763 MWh/year**	Specific prod.	1803 kWh/kWp/year
	Performance Ratio PR	83.4 %		

Normalized productions (per installed kWp): Nominal power 6524 kWp



Performance Ratio PR



PC18_IdahoFalls_Rev3

Balances and main results

	GlobHor	T Amb	GlobInc	GlobEff	EArray	E_Grid	EffArrR	EffSysR
	kWh/m²	°C	kWh/m²	kWh/m²	MWh	MWh	%	%
January	34.6	-7.63	45.3	41.6	276	270	16.00	15.64
February	62.3	-6.02	78.9	73.2	481	472	16.02	15.72
March	138.9	1.52	191.4	180.6	1129	1109	15.50	15.23
April	170.8	8.07	225.0	212.6	1252	1230	14.62	14.36
May	200.8	12.25	258.1	244.9	1393	1369	14.18	13.93
June	219.3	16.42	288.2	274.8	1521	1495	13.86	13.62
July	241.0	20.60	323.5	307.7	1698	1669	13.78	13.55
August	203.6	19.01	277.6	263.8	1505	1479	14.24	14.00
September	149.5	13.70	204.5	193.1	1143	1123	14.69	14.43
October	98.8	6.88	136.2	127.8	790	775	15.23	14.96
November	59.9	0.19	83.5	77.6	499	490	15.70	15.41
December	38.7	-2.59	48.6	44.5	288	282	15.56	15.21
Year	1618.2	6.94	2160.8	2042.0	11975	11763	14.56	14.30

Legends:				
	GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
	GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

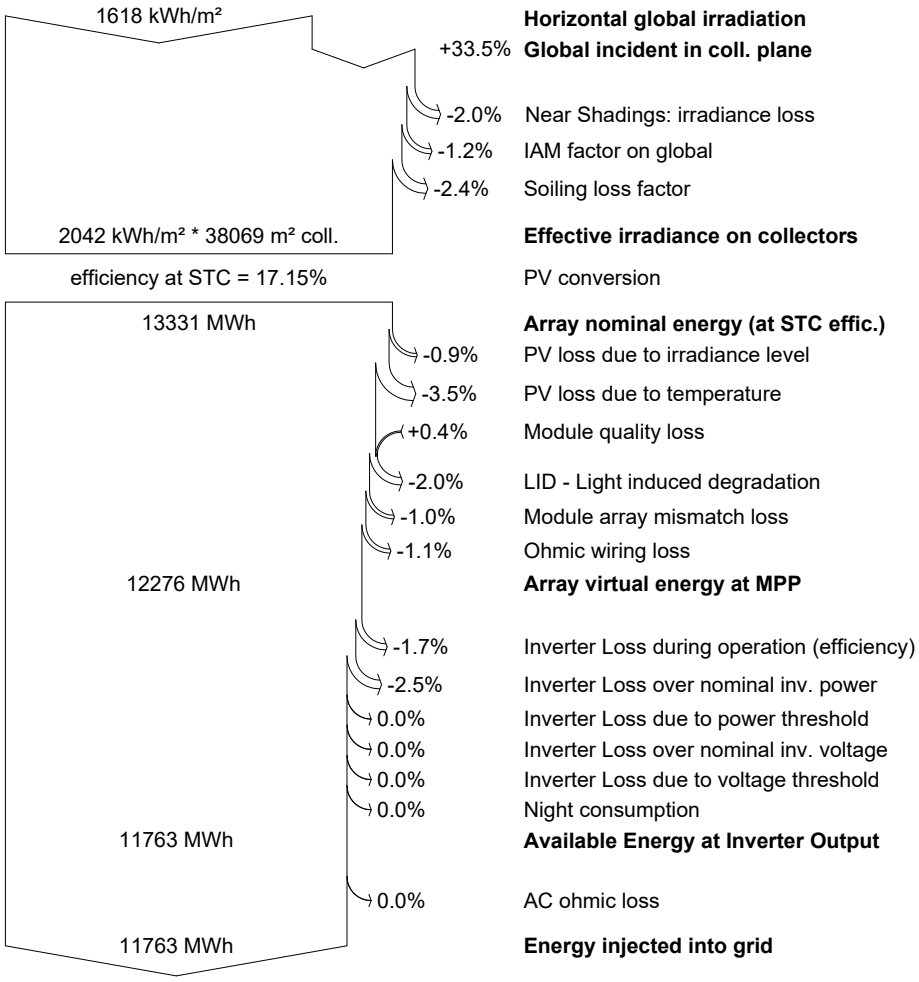
Grid-Connected System: Loss diagram

Project : **PC18-Grid-IdahoFallsID-SAT**

Simulation variant : **PC18_IdahoFalls_Rev3**

Main system parameters	System type	**Grid-Connected**		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **PC18-LakeviewOR**

Geographical Site	**Lakeview**		Country	**United States**
Situation	Latitude	42.2°N	Longitude	120.4°W
Time defined as	Legal Time	Time zone UT-8	Altitude	1441 m
	Albedo	0.20		
Meteo data:	**Lakeview**	TMY - NREL: TMY3 hourly DB (1991-2005)		

Simulation variant : **PC18-LakeviewOR_Rev2**

Simulation date 31/08/18 14h20

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	5.50 m	Collector width	1.98 m
Inactive band	Left	0.20 m	Right	0.20 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			

PV Array Characteristics

PV module	Si-poly	Model	**CS3U-340P 1500V**		
		Manufacturer	Canadian Solar Inc.		
		Orientation	#1	Tilt/Azimuth	30°/0°
Number of PV modules		In series	26 modules	In parallel	738 strings
Total number of PV modules		Nb. modules	19188	Unit Nom. Power	340 Wp
Array global power		Nominal (STC)	**6524 kWp**	At operating cond.	5890 kWp (50°C)
Array operating characteristics (50°C)		U mpp	895 V	I mpp	6580 A
Total area		Module area	**38069 m²**	Cell area	33931 m²
Inverter		Model	**SMA SC2500 EV Prelim!**		
		Manufacturer	SMA		
Characteristics		Operating Voltage	850-1425 V	Unit Nom. Power	2500 kWac
Inverter pack		Nb. of inverters	2 units	Total Power	5000 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.5%	2.5%	2.5%	2.0%	2.0%	2.0%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.5 mOhm	Loss Fraction	1.6 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP

Grid-Connected System: Simulation parameters (continued)

Incidence effect, user defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.00	1.00	1.00	0.99	0.99	0.97	0.92	0.76	0.00

System loss factors

Wiring Ohmic Loss Wires 0 m 3x0.0 mm² Loss Fraction 0.0 % at STC

User's needs : Unlimited load (grid)

Grid-Connected System: Horizon definition

Project : **PC18-LakeviewOR**

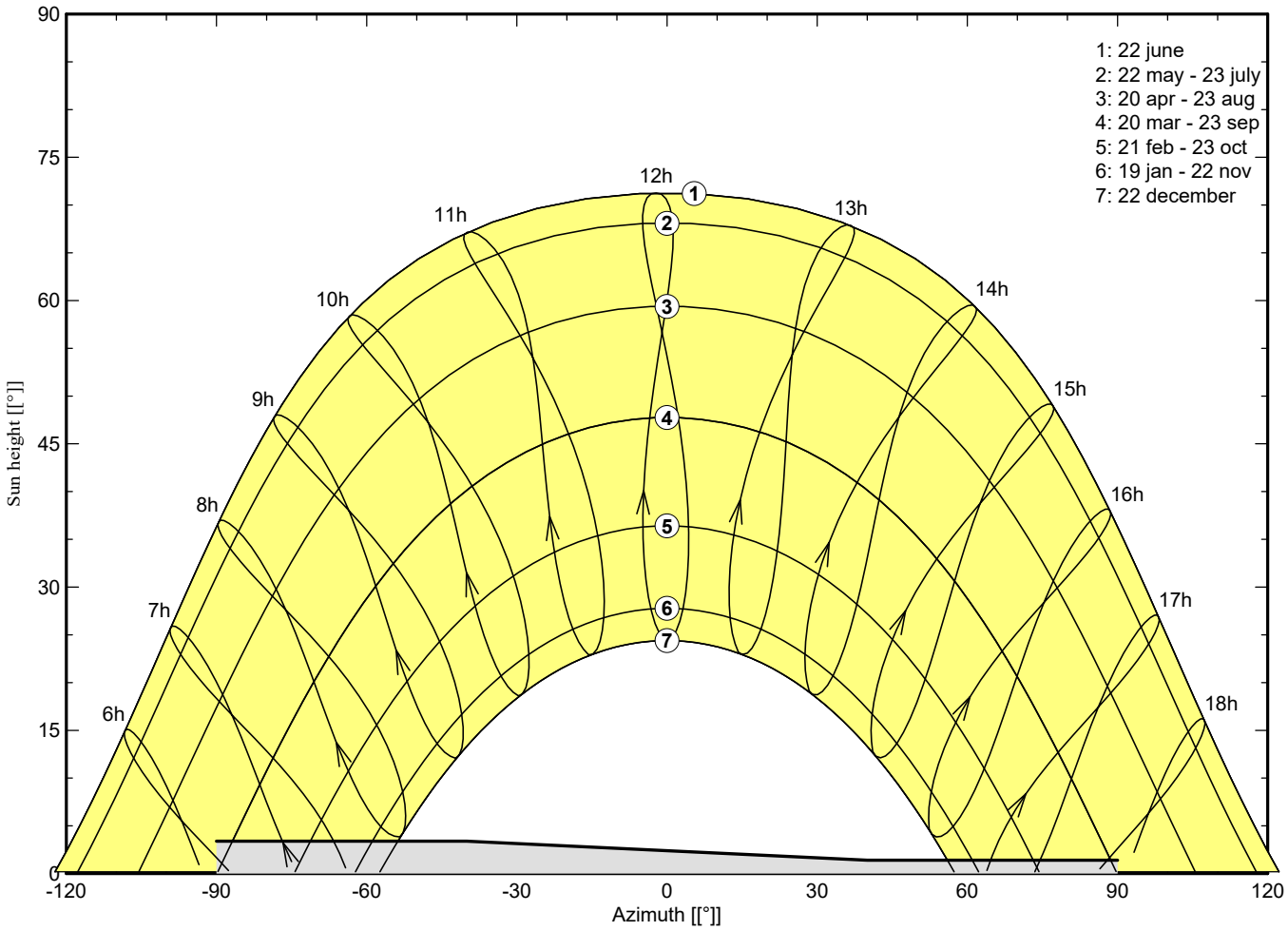
Simulation variant : **PC18-LakeviewOR_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Horizon	Average Height	2.4°	Diffuse Factor	0.99
	Albedo Factor	100 %	Albedo Fraction	0.96

Height [°]	3.4	3.4	1.4	1.4
Azimuth [°]	-90	-40	40	90

Horizon



Grid-Connected System: Main results

Project : **PC18-LakeviewOR**

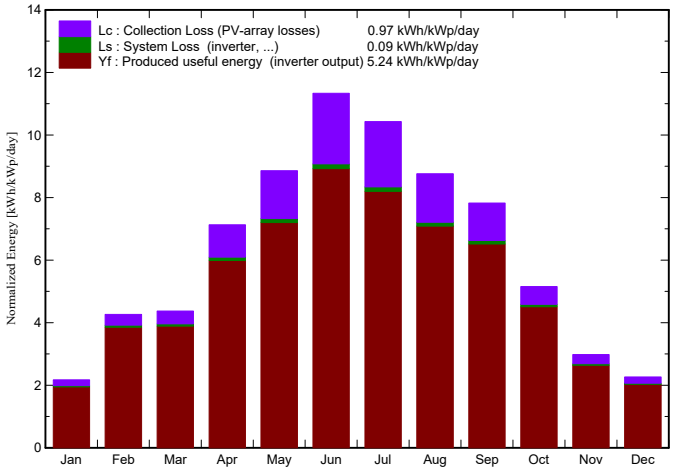
Simulation variant : **PC18-LakeviewOR_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

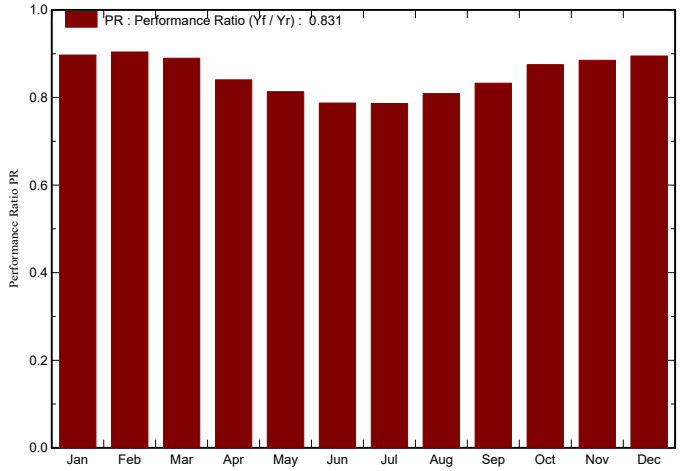
Main simulation results

System Production	**Produced Energy**	**12468 MWh/year**	Specific prod.	1911 kWh/kWp/year
	Performance Ratio PR	83.1 %		

Normalized productions (per installed kWp): Nominal power 6524 kWp



Performance Ratio PR



PC18-LakeviewOR_Rev2

Balances and main results

	GlobHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	EffArrR %	EffSysR %
January	52.8	-1.22	67.4	62.3	402	394	15.68	15.37
February	85.1	-0.46	119.4	112.0	717	704	15.77	15.49
March	106.7	2.86	135.6	127.4	802	787	15.53	15.24
April	163.1	5.42	213.8	202.5	1193	1172	14.66	14.40
May	209.3	9.94	274.6	261.2	1482	1457	14.18	13.94
June	251.2	16.42	340.1	325.4	1777	1747	13.72	13.49
July	242.7	20.83	323.3	307.4	1687	1659	13.71	13.48
August	198.5	17.73	271.7	258.0	1459	1434	14.11	13.86
September	167.3	14.61	234.7	222.3	1297	1275	14.52	14.27
October	114.2	6.91	159.8	150.6	928	912	15.26	14.99
November	63.8	1.73	89.5	83.4	527	517	15.45	15.16
December	49.6	-0.87	70.3	65.0	418	410	15.63	15.33
Year	1704.3	7.87	2300.2	2177.6	12690	12468	14.49	14.24

Legends:				
	GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
	GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

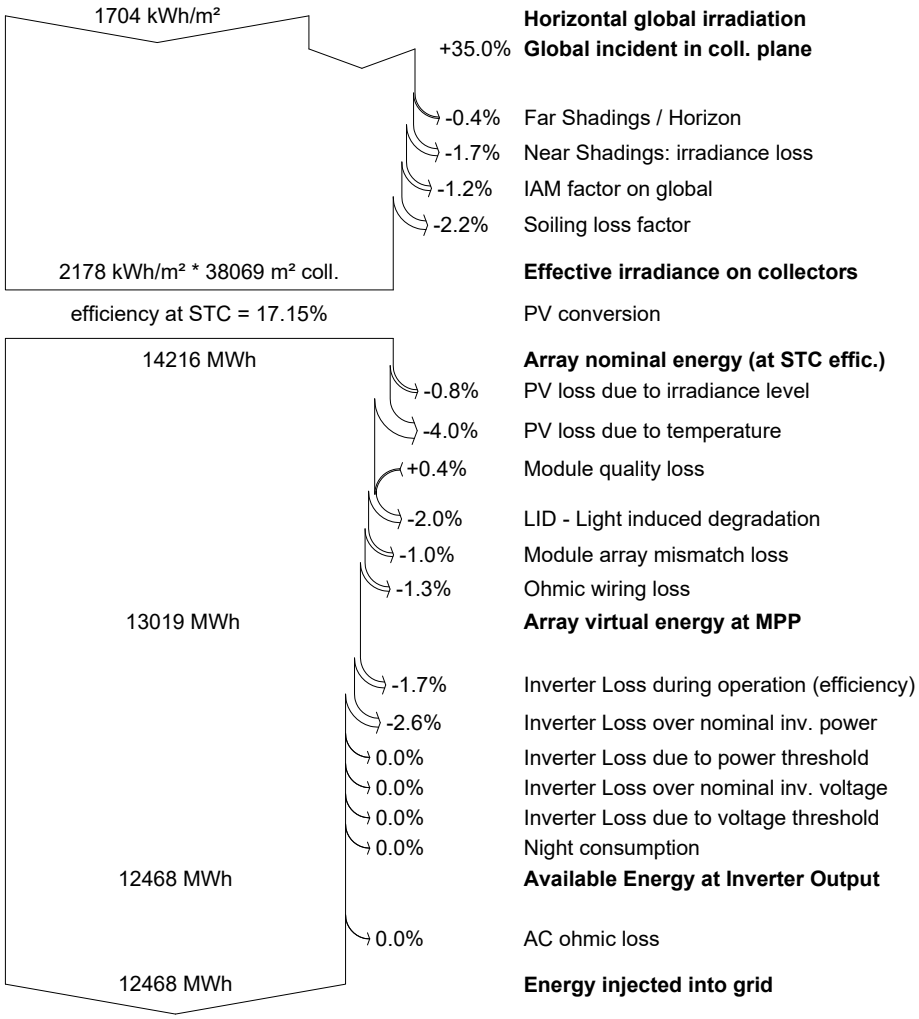
Grid-Connected System: Loss diagram

Project : **PC18-LakeviewOR**

Simulation variant : **PC18-LakeviewOR_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **PC18-Grid-MildfordUT-SAT**

Geographical Site	**MilfordUT_S1**		Country	**United States**
Situation	Latitude	38.4°N	Longitude	113.0°W
Time defined as	Legal Time	Time zone UT-7	Altitude	1563 m
	Albedo	0.20		
Meteo data:	**MilfordUT_NSRDB**	TMY - NREL: TMY3 hourly DB (1991-2005)		

Simulation variant : **PC18-MilfordUT_Rev0**

Simulation date 31/08/18 14h47

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	5.50 m	Collector width	1.98 m
Inactive band	Left	0.20 m	Right	0.20 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			

PV Array Characteristics

PV module	Si-poly	Model	**CS3U-340P 1500V**		
		Manufacturer	Canadian Solar Inc.		
		Orientation	#1	Tilt/Azimuth	30°/0°
Number of PV modules		In series	26 modules	In parallel	738 strings
Total number of PV modules		Nb. modules	19188	Unit Nom. Power	340 Wp
Array global power		Nominal (STC)	**6524 kWp**	At operating cond.	5890 kWp (50°C)
Array operating characteristics (50°C)		U mpp	895 V	I mpp	6580 A
Total area		Module area	**38069 m²**	Cell area	33931 m²
Inverter		Model	**SMA SC2500 EV Prelim!**		
		Manufacturer	SMA		
Characteristics		Operating Voltage	850-1425 V	Unit Nom. Power	2500 kWac
Inverter pack		Nb. of inverters	2 units	Total Power	5000 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.5%	2.5%	2.0%	2.0%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.3 mOhm	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP

Grid-Connected System: Simulation parameters (continued)

Incidence effect, user defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.00	1.00	1.00	0.99	0.99	0.97	0.92	0.76	0.00

System loss factors

Wiring Ohmic Loss Wires 0 m 3x5000.0 mm² Loss Fraction 0.0 % at STC

User's needs : Unlimited load (grid)

Grid-Connected System: Horizon definition

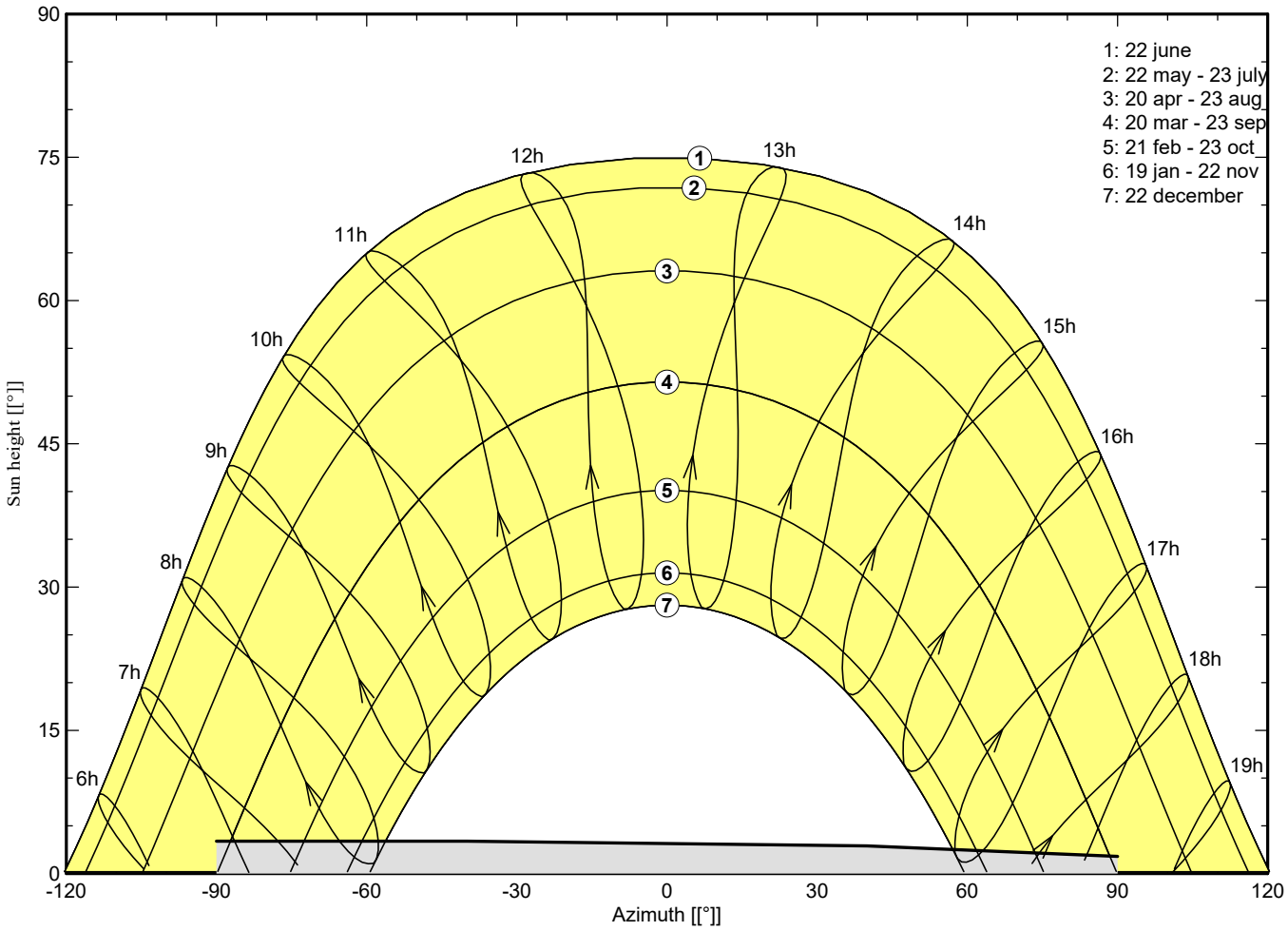
Project : **PC18-Grid-MildfordUT-SAT**

Simulation variant : **PC18-MilfordUT_Rev0**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Horizon	Average Height	3.0°	Diffuse Factor	0.98
	Albedo Factor	100 %	Albedo Fraction	0.94

Height [°]	3.4	3.4	2.9	1.8
Azimuth [°]	-90	-40	40	90



Grid-Connected System: Main results

Project : **PC18-Grid-MildfordUT-SAT**

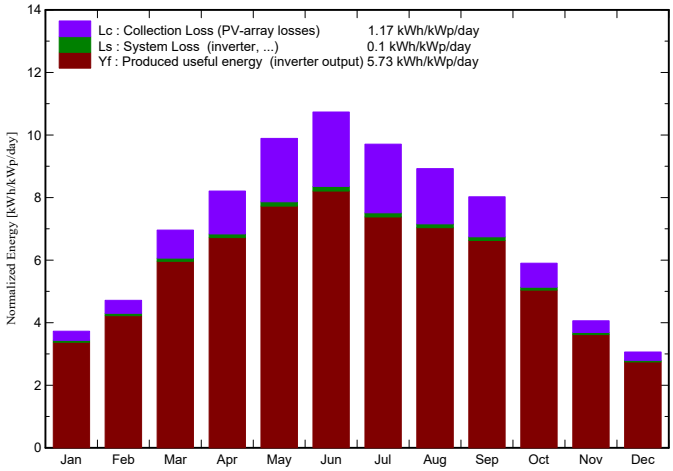
Simulation variant : **PC18-MilfordUT_Rev0**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

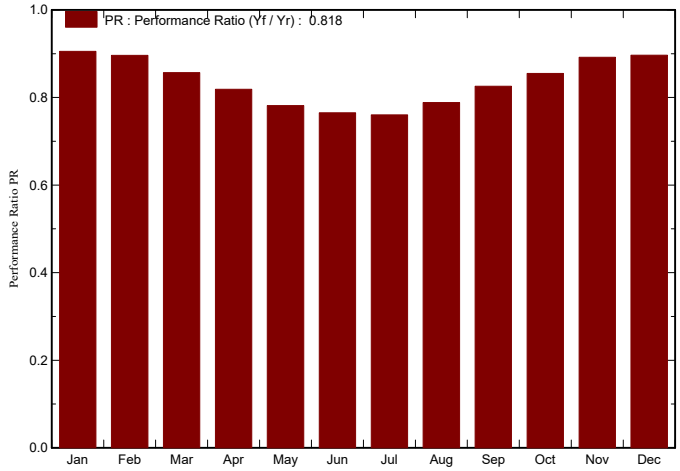
Main simulation results

System Production	**Produced Energy**	**13645 MWh/year**	Specific prod.	2092 kWh/kWp/year
	Performance Ratio PR	81.8 %		

Normalized productions (per installed kWp): Nominal power 6524 kWp



Performance Ratio PR



PC18-MilfordUT_Rev0

Balances and main results

	GlobHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	EffArrR %	EffSysR %
January	83.0	-1.63	115.6	107.5	695	683	15.80	15.52
February	97.2	0.96	132.0	123.7	786	772	15.63	15.36
March	158.1	2.97	215.8	204.6	1227	1206	14.94	14.68
April	188.5	7.14	246.3	234.0	1339	1315	14.28	14.03
May	233.1	15.67	306.7	290.9	1591	1563	13.63	13.39
June	243.9	19.11	322.0	306.2	1635	1607	13.34	13.11
July	230.2	23.97	301.0	285.9	1519	1493	13.26	13.03
August	207.6	23.16	276.7	262.8	1448	1423	13.75	13.51
September	175.2	15.35	240.8	228.6	1320	1297	14.40	14.15
October	132.0	11.70	182.9	172.2	1038	1020	14.91	14.65
November	86.8	1.58	121.9	113.8	722	709	15.56	15.28
December	67.8	-1.75	94.9	87.6	566	555	15.66	15.37
Year	1903.4	9.92	2556.6	2417.9	13887	13645	14.27	14.02

Legends:

GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
T Amb	Ambient Temperature	E_Grid	Energy injected into grid
GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

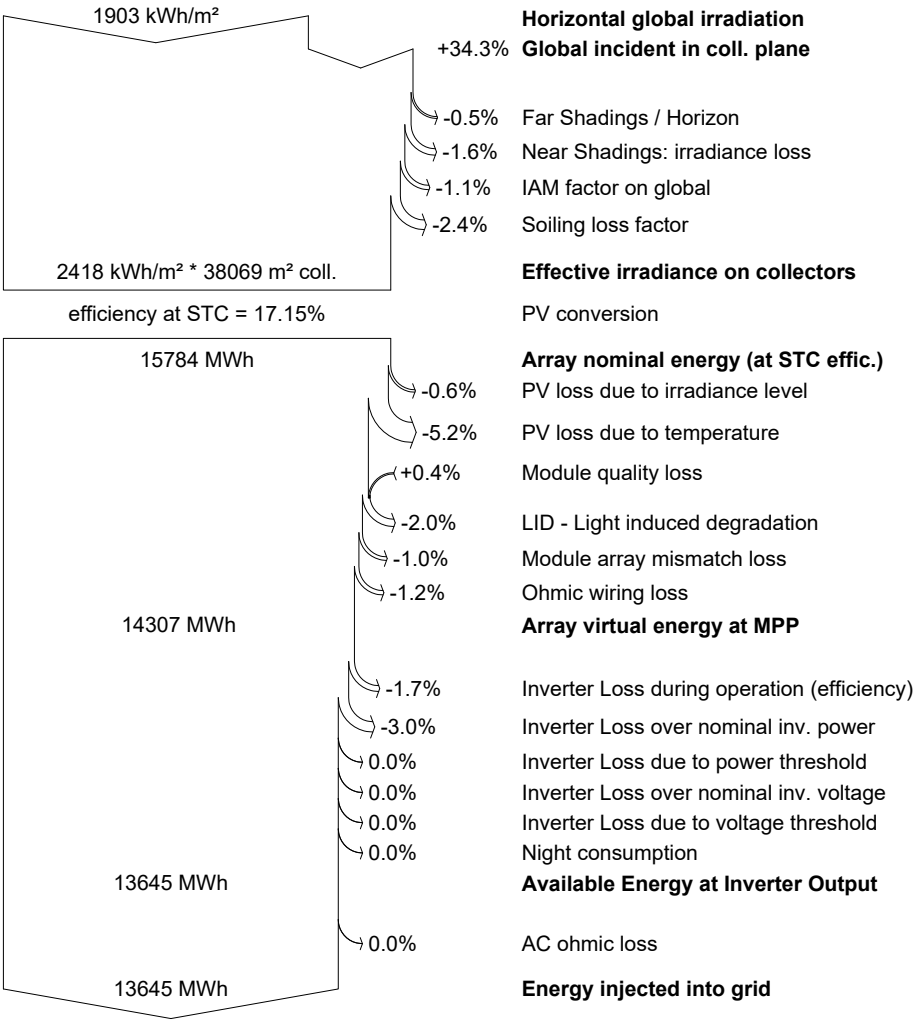
Grid-Connected System: Loss diagram

Project : **PC18-Grid-MildfordUT-SAT**

Simulation variant : **PC18-MilfordUT_Rev0**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **PC18-Grid-RockSpringsWY-SAT**

Geographical Site	**Rock Springs Arpt**		Country	**United States**
Situation	Latitude	41.5°N	Longitude	109.4°W
Time defined as	Legal Time	Time zone UT-7	Altitude	1000 m
	Albedo	0.20		
Meteo data:	**Rock Springs Arpt**	TMY - NREL: TMY3 hourly DB (1991-2005)		

Simulation variant : **PC18-RockSpringsWY_Rev2**

Simulation date 31/08/18 15h16

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	5.50 m	Collector width	1.98 m
Inactive band	Left	0.20 m	Right	0.20 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Average Height	4.2°		
Near Shadings	Linear shadings			

PV Array Characteristics

PV module	Si-poly	Model	**CS3U-340P 1500V**		
		Manufacturer	Canadian Solar Inc.		
		Orientation	#1	Tilt/Azimuth	30°/0°
Number of PV modules		In series	26 modules	In parallel	738 strings
Total number of PV modules		Nb. modules	19188	Unit Nom. Power	340 Wp
Array global power		Nominal (STC)	**6524 kWp**	At operating cond.	5890 kWp (50°C)
Array operating characteristics (50°C)		U mpp	895 V	I mpp	6580 A
Total area		Module area	**38069 m²**	Cell area	33931 m²
Inverter		Model	**SMA SC2500 EV Prelim!**		
		Manufacturer	SMA		
Characteristics		Operating Voltage	850-1425 V	Unit Nom. Power	2500 kWac
Inverter pack		Nb. of inverters	2 units	Total Power	5000 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.5%	2.5%	2.5%	2.5%	2.0%	2.0%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.3 mOhm	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP

Grid-Connected System: Simulation parameters (continued)

Incidence effect, user defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.00	1.00	1.00	0.99	0.99	0.97	0.92	0.76	0.00

System loss factors

Wiring Ohmic Loss Wires 0 m 3x5000.0 mm² Loss Fraction 0.0 % at STC

User's needs : Unlimited load (grid)

Grid-Connected System: Horizon definition

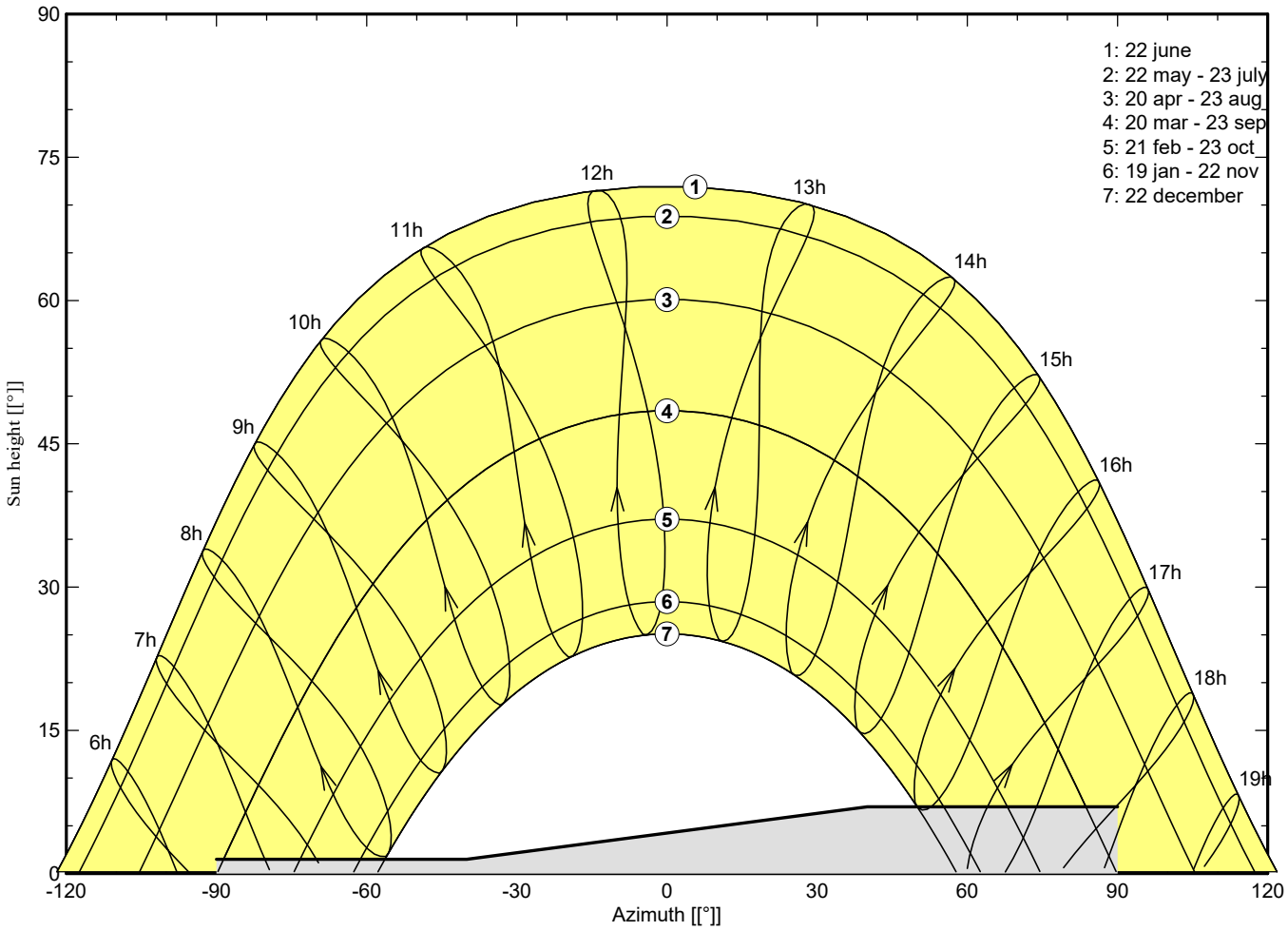
Project : **PC18-Grid-RockSpringsWY-SAT**

Simulation variant : **PC18-RockSpringsWY_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	4.2°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Horizon	Average Height	4.2°	Diffuse Factor	0.96
	Albedo Factor	100 %	Albedo Fraction	0.83

Height [°]	1.5	1.5	7.0	7.0
Azimuth [°]	-90	-40	40	90



Grid-Connected System: Main results

Project : **PC18-Grid-RockSpringsWY-SAT**

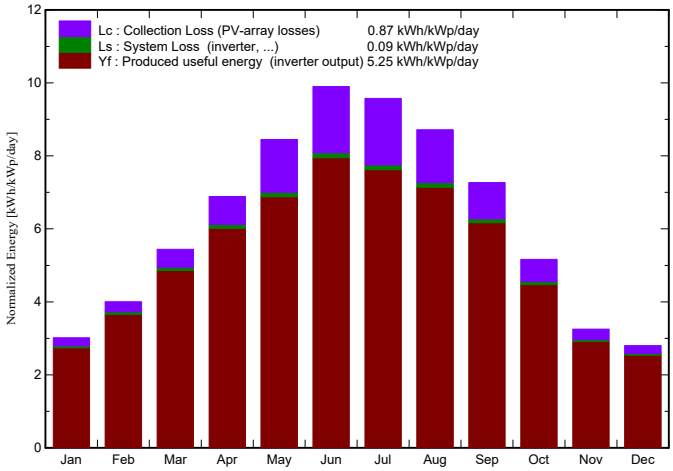
Simulation variant : **PC18-RockSpringsWY_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	4.2°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

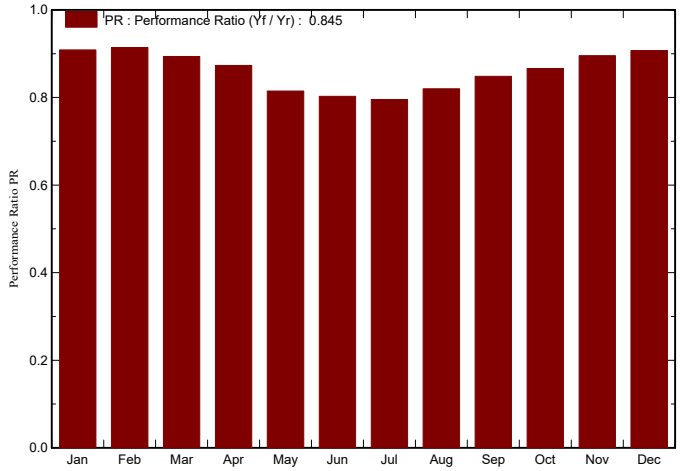
Main simulation results

System Production	**Produced Energy**	**12510 MWh/year**	Specific prod.	1918 kWh/kWp/year
	Performance Ratio PR	84.5 %		

Normalized productions (per installed kWp): Nominal power 6524 kWp



Performance Ratio PR



PC18-RockSpringsWY_Rev2

Balances and main results

	GlobHor kWh/m²	T Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	EffArrR %	EffSysR %
January	68.3	-4.70	93.6	85.6	565	555	15.86	15.57
February	84.1	-3.58	112.0	103.5	681	668	15.96	15.67
March	127.1	0.22	168.6	157.3	1001	983	15.59	15.32
April	156.6	4.99	206.7	194.1	1198	1177	15.23	14.96
May	200.6	10.16	261.8	248.2	1416	1392	14.21	13.96
June	224.4	17.24	297.0	282.8	1582	1555	14.00	13.76
July	223.3	19.89	296.9	281.4	1568	1541	13.87	13.63
August	202.1	18.73	270.2	255.6	1470	1445	14.29	14.05
September	158.0	12.84	218.1	204.9	1228	1207	14.79	14.54
October	116.0	7.61	160.1	149.2	921	905	15.11	14.84
November	72.1	-0.85	97.5	89.7	580	570	15.63	15.34
December	60.8	-5.39	86.8	79.4	523	514	15.84	15.54
Year	1693.5	6.49	2269.3	2131.7	12734	12510	14.74	14.48

Legends:			
GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
T Amb	Ambient Temperature	E_Grid	Energy injected into grid
GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

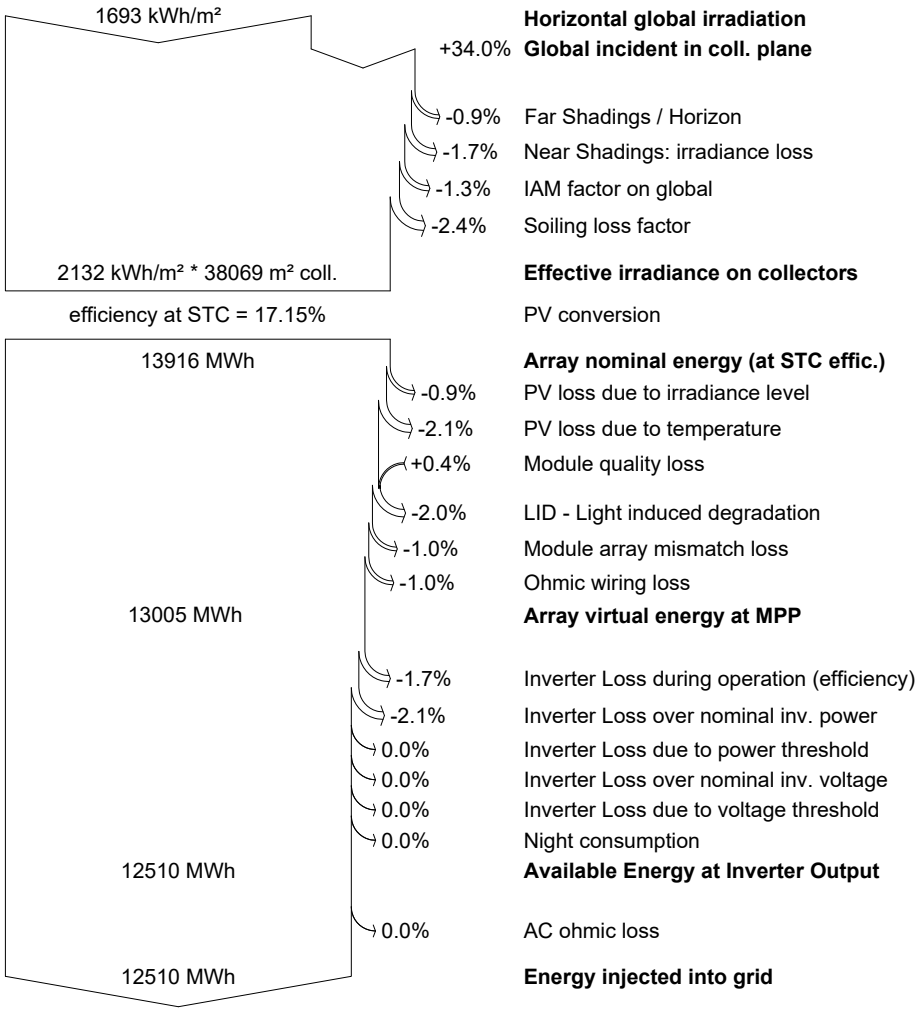
Grid-Connected System: Loss diagram

Project : **PC18-Grid-RockSpringsWY-SAT**

Simulation variant : **PC18-RockSpringsWY_Rev2**

Main system parameters	System type	**Grid-Connected**		
Horizon	Average Height	4.2°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **PC18-Grid-YakimaWA-SAT**

Geographical Site	**Yakima**		Country	**United States**
Situation	Latitude	46.6°N	Longitude	120.5°W
Time defined as	Legal Time	Time zone UT-8	Altitude	320 m
	Albedo	0.20		
Meteo data:	**Yakima Air Terminal**	TMY - NREL: TMY3 hourly DB (1991-2005)		

Simulation variant : **YakimaWA_5MW-SAT_Report**

Simulation date 31/08/18 15h29

Simulation parameters

Tracking plane, tilted Axis	Axis Tilt	0°	Axis Azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
Backtracking strategy	Tracker Spacing	5.50 m	Collector width	1.98 m
Inactive band	Left	0.20 m	Right	0.20 m
Models used	Transposition	Perez	Diffuse	Imported
Horizon	Free Horizon			
Near Shadings	Linear shadings			

PV Array Characteristics

PV module	Si-poly	Model	**CS3U-340P 1500V**		
		Manufacturer	Canadian Solar Inc.		
		Orientation	#1	Tilt/Azimuth	30°/0°
Number of PV modules		In series	26 modules	In parallel	738 strings
Total number of PV modules		Nb. modules	19188	Unit Nom. Power	340 Wp
Array global power		Nominal (STC)	**6524 kWp**	At operating cond.	5890 kWp (50°C)
Array operating characteristics (50°C)		U mpp	895 V	I mpp	6580 A
Total area		Module area	**38069 m²**	Cell area	33931 m²
Inverter		Model	**SMA SC2500 EV Prelim!**		
		Manufacturer	SMA		
Characteristics		Operating Voltage	850-1425 V	Unit Nom. Power	2500 kWac
Inverter pack		Nb. of inverters	2 units	Total Power	5000 kWac

PV Array loss factors

Array Soiling Losses

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sep.	Oct.	Nov.	Dec.
2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%

Thermal Loss factor	Uc (const)	25.0 W/m²K	Uv (wind)	1.2 W/m²K / m/s
Wiring Ohmic Loss	Global array res.	2.5 mOhm	Loss Fraction	1.6 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.4 %
Module Mismatch Losses			Loss Fraction	1.0 % at MPP

Grid-Connected System: Simulation parameters (continued)

Incidence effect, user defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.00	1.00	1.00	0.99	0.99	0.97	0.92	0.76	0.00

System loss factors

Wiring Ohmic Loss Wires 0 m 3x0.0 mm² Loss Fraction 0.0 % at STC

User's needs : Unlimited load (grid)

Grid-Connected System: Main results

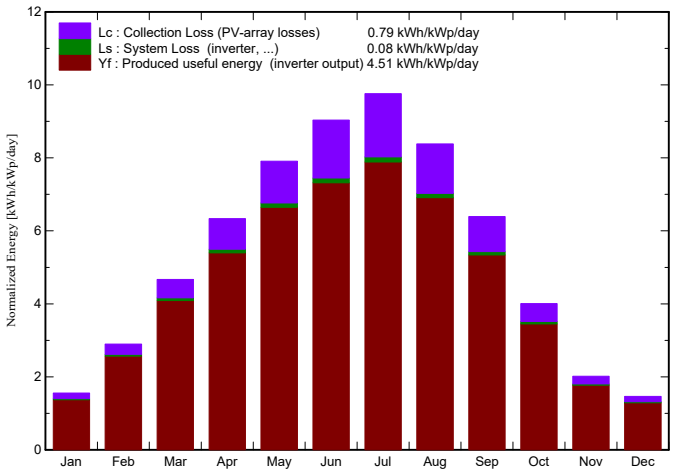
Project : **PC18-Grid-YakimaWA-SAT**

Simulation variant : **YakimaWA_5MW-SAT_Report**

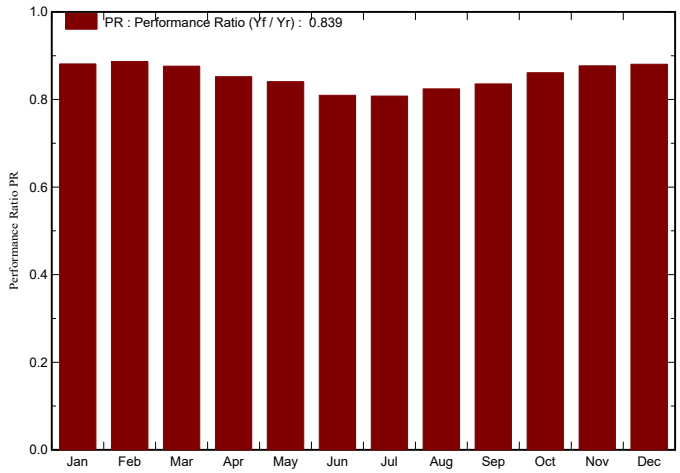
Main system parameters	System type	**Grid-Connected**		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results				
System Production	**Produced Energy**	**10749 MWh/year**	Specific prod.	1648 kWh/kWp/year
	Performance Ratio PR	83.9 %		

Normalized productions (per installed kWp): Nominal power 6524 kWp



Performance Ratio PR



YakimaWA_5MW-SAT_Report

Balances and main results

	GlobHor	T Amb	GlobInc	GlobEff	EArray	E_Grid	EffArrR	EffSysR
	kWh/m²	°C	kWh/m²	kWh/m²	MWh	MWh	%	%
January	41.1	-1.43	48.3	43.9	284	278	15.45	15.10
February	62.8	2.53	81.1	75.2	478	469	15.50	15.20
March	108.9	5.93	144.8	135.8	842	827	15.29	15.01
April	146.2	11.57	190.1	178.8	1076	1056	14.86	14.60
May	188.4	14.18	245.1	231.0	1368	1344	14.66	14.40
June	208.6	19.24	271.1	256.3	1458	1432	14.12	13.87
July	225.0	22.28	302.6	287.1	1623	1595	14.09	13.84
August	190.6	19.68	259.9	246.3	1422	1397	14.37	14.12
September	140.7	15.67	191.7	180.6	1064	1045	14.57	14.32
October	91.2	9.06	124.3	116.2	711	698	15.03	14.76
November	47.3	2.49	60.6	55.6	354	346	15.35	15.02
December	36.2	-2.00	45.4	41.2	267	261	15.43	15.09
Year	1486.8	9.97	1964.9	1847.9	10946	10749	14.63	14.37

Legends:				
	GlobHor	Horizontal global irradiation	EArray	Effective energy at the output of the array
	T Amb	Ambient Temperature	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	EffArrR	Effic. Eout array / rough area
	GlobEff	Effective Global, corr. for IAM and shadings	EffSysR	Effic. Eout system / rough area

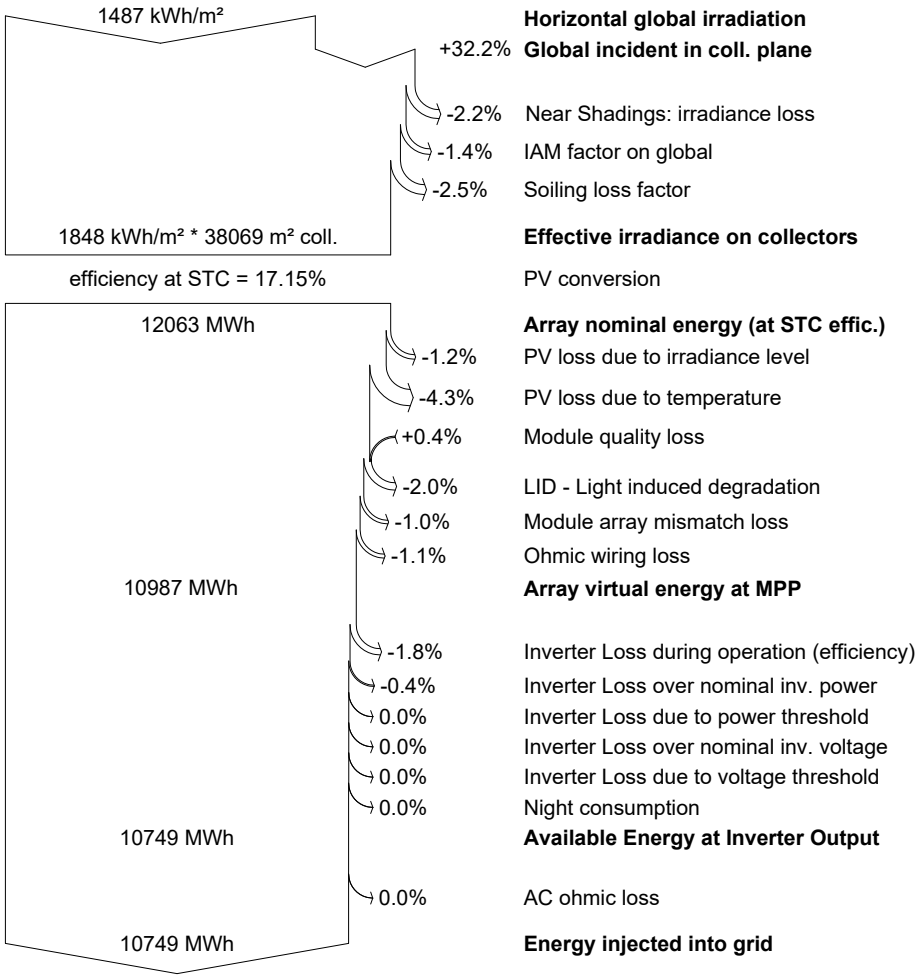
Grid-Connected System: Loss diagram

Project : **PC18-Grid-YakimaWA-SAT**

Simulation variant : **YakimaWA_5MW-SAT_Report**

Main system parameters	System type	**Grid-Connected**		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis Azimuth	0°
PV modules	Model	CS3U-340P 1500V	Pnom	340 Wp
PV Array	Nb. of modules	19188	Pnom total	**6524 kWp**
Inverter	Model	SMA SC2500 EV Prelim!	Pnom	2500 kW ac
Inverter pack	Nb. of units	2.0	Pnom total	**5000 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



APPENDIX C – SOLAR OUTPUT SUMMARY

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 31-Aug-18

Site Information	
City / State:	Idaho Falls, Idaho
Latitude (N):	43.5 °
Longitude (W):	-112 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	32 °C
ASHRAE Extreme Mean Min. Temp.	-25 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	N/A %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	11597.3 MWh
AC capacity factor - Inv Rating	26.48%
AC capacity factor - POI Rating	26.48%
DC capacity factor	20.00%
Specific Production	1752 kWh/kWp/yr
Performance Ratio PR	81.08%
Night time losses	-21.1 MWh
Plant Output Limitations	0.00%

Facility Level Information	
Nameplate Capacity	**6.62 MWDC**
Number of modules	19188
Nameplate Capacity	**5.00 MWAC**
Number of arrays	1
Interconnection Limit	**5.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.324

Weather	
Source	TMY3
GHI	1618.2 kWh/m2
DHI	kWh/m2
Global POA	2160.8 kWh/m2
Average Temp.	6.94 °C
Average Temp. (Generation)	11.48 °C
Average Wind	3.84 m/s
Average Wind (Generation)	4.53 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	0.70%
HV transformer no-load losses	0.00%
HV transformer full load losses	0.00%
HV line	0.00%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 28-Aug-18

Site Information	
City / State:	Idaho Falls, Idaho
Latitude (N):	43.5 °
Longitude (W):	-112 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	32 °C
ASHRAE Extreme Mean Min. Temp.	-25 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	N/A %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	122928.5 MWh
AC capacity factor - Inv Rating	25.51%
AC capacity factor - POI Rating	28.07%
DC capacity factor	19.27%
Specific Production	1688 kWh/kWp/yr
Performance Ratio PR	78.13%
Night time losses	-408.8 MWh
Plant Output Limitations	2.63%

Facility Level Information	
Nameplate Capacity	**72.82 MWDC**
Number of modules	211068
Nameplate Capacity	**55.00 MWAC**
Number of arrays	11
Interconnection Limit	**50.00 MWAC**
Inteconnection Voltage	115 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1618.2 kWh/m2
DHI	kWh/m2
Global POA	2160.8 kWh/m2
Average Temp.	6.94 °C
Average Temp. (Generation)	11.48 °C
Average Wind	3.84 m/s
Average Wind (Generation)	4.53 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 31-Aug-18

Site Information	
City / State:	Idaho Falls, Idaho
Latitude (N):	43.5 °
Longitude (W):	-112 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	32 °C
ASHRAE Extreme Mean Min. Temp.	-25 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	N/A %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	491714.0 MWh
AC capacity factor - Inv Rating	25.51%
AC capacity factor - POI Rating	28.07%
DC capacity factor	19.27%
Specific Production	1688 kWh/kWp/yr
Performance Ratio PR	78.13%
Night time losses	-1635.2 MWh
Plant Output Limitations	2.63%

Facility Level Information	
Nameplate Capacity	**291.27 MWDC**
Number of modules	844272
Nameplate Capacity	**220.00 MWAC**
Number of arrays	44
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	230 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1618.2 kWh/m2
DHI	kWh/m2
Global POA	2160.8 kWh/m2
Average Temp.	6.94 °C
Average Temp. (Generation)	11.48 °C
Average Wind	3.84 m/s
Average Wind (Generation)	4.53 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Lakeview, OR
Latitude (N):	42.2 °
Longitude (W):	-120 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	31 °C
ASHRAE Extreme Mean Min. Temp.	-22 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	12291.9 MWh
AC capacity factor - Inv Rating	28.06%
AC capacity factor - POI Rating	28.06%
DC capacity factor	21.20%
Specific Production	1857 kWh/kWp/yr
Performance Ratio PR	80.72%
Night time losses	-21.2 MWh
Plant Output Limitations	0.00%

Facility Level Information	
Nameplate Capacity	**6.62 MWDC**
Number of modules	19188
Nameplate Capacity	**5.00 MWAC**
Number of arrays	1
Interconnection Limit	**5.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.324

Weather	
Source	TMY3
GHI	1704.3 kWh/m2
DHI	kWh/m2
Global POA	2300.2 kWh/m2
Average Temp.	7.87 °C
Average Temp. (Generation)	12.57 °C
Average Wind	3.33 m/s
Average Wind (Generation)	3.63 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	0.70%
HV transformer no-load losses	0.00%
HV transformer full load losses	0.00%
HV line	0.00%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Lakeview, OR
Latitude (N):	42.2 °
Longitude (W):	-120 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	31 °C
ASHRAE Extreme Mean Min. Temp.	-22 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	130139.1 MWh
AC capacity factor - Inv Rating	27.01%
AC capacity factor - POI Rating	29.71%
DC capacity factor	20.40%
Specific Production	1787 kWh/kWp/yr
Performance Ratio PR	77.70%
Night time losses	-411.2 MWh
Plant Output Limitations	2.75%

Facility Level Information	
Nameplate Capacity	**72.82 MWDC**
Number of modules	211068
Nameplate Capacity	**55.00 MWAC**
Number of arrays	11
Interconnection Limit	**50.00 MWAC**
Inteconnection Voltage	115 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1704.3 kWh/m2
DHI	kWh/m2
Global POA	2300.2 kWh/m2
Average Temp.	7.87 °C
Average Temp. (Generation)	12.57 °C
Average Wind	3.33 m/s
Average Wind (Generation)	3.63 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Lakeview, OR
Latitude (N):	42.2 °
Longitude (W):	-120 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	31 °C
ASHRAE Extreme Mean Min. Temp.	-22 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	520556.4 MWh
AC capacity factor - Inv Rating	27.01%
AC capacity factor - POI Rating	29.71%
DC capacity factor	20.40%
Specific Production	1787 kWh/kWp/yr
Performance Ratio PR	77.70%
Night time losses	-1644.8 MWh
Plant Output Limitations	2.75%

Facility Level Information	
Nameplate Capacity	**291.27 MWDC**
Number of modules	844272
Nameplate Capacity	**220.00 MWAC**
Number of arrays	44
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	230 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1704.3 kWh/m2
DHI	kWh/m2
Global POA	2300.2 kWh/m2
Average Temp.	7.87 °C
Average Temp. (Generation)	12.57 °C
Average Wind	3.33 m/s
Average Wind (Generation)	3.63 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Milford, UT
Latitude (N):	38.4 °
Longitude (W):	-113 °
Altitude	1534 m
ASHRAE Cooling DB Temp.	34.9 °C
ASHRAE Extreme Mean Min. Temp.	-23.1 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	13450.8 MWh
AC capacity factor - Inv Rating	30.71%
AC capacity factor - POI Rating	30.71%
DC capacity factor	23.20%
Specific Production	2032 kWh/kWp/yr
Performance Ratio PR	79.48%
Night time losses	-20.8 MWh
Plant Output Limitations	0.00%

Facility Level Information	
Nameplate Capacity	**6.62 MWDC**
Number of modules	19188
Nameplate Capacity	**5.00 MWAC**
Number of arrays	1
Interconnection Limit	**5.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.324

Weather	
Source	NSRDB PSMv3
GHI	1903.4 kWh/m2
DHI	kWh/m2
Global POA	2556.6 kWh/m2
Average Temp.	9.92 °C
Average Temp. (Generation)	14.91 °C
Average Wind	2.11 m/s
Average Wind (Generation)	2.82 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	0.70%
HV transformer no-load losses	0.00%
HV transformer full load losses	0.00%
HV line	0.00%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Milford, UT
Latitude (N):	38.4 °
Longitude (W):	-113 °
Altitude	1534 m
ASHRAE Cooling DB Temp.	34.9 °C
ASHRAE Extreme Mean Min. Temp.	-23.1 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	142375.3 MWh
AC capacity factor - Inv Rating	29.55%
AC capacity factor - POI Rating	32.51%
DC capacity factor	22.32%
Specific Production	1955 kWh/kWp/yr
Performance Ratio PR	76.48%
Night time losses	-401.9 MWh
Plant Output Limitations	2.76%

Facility Level Information	
Nameplate Capacity	**72.82 MWDC**
Number of modules	211068
Nameplate Capacity	**55.00 MWAC**
Number of arrays	11
Interconnection Limit	**50.00 MWAC**
Inteconnection Voltage	115 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	NSRDB PSMv3
GHI	1903.4 kWh/m2
DHI	kWh/m2
Global POA	2556.6 kWh/m2
Average Temp.	9.92 °C
Average Temp. (Generation)	14.91 °C
Average Wind	2.11 m/s
Average Wind (Generation)	2.82 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Milford, UT
Latitude (N):	38.4 °
Longitude (W):	-113 °
Altitude	1534 m
ASHRAE Cooling DB Temp.	34.9 °C
ASHRAE Extreme Mean Min. Temp.	-23.1 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	569501.1 MWh
AC capacity factor - Inv Rating	29.55%
AC capacity factor - POI Rating	32.51%
DC capacity factor	22.32%
Specific Production	1955 kWh/kWp/yr
Performance Ratio PR	76.48%
Night time losses	-1607.7 MWh
Plant Output Limitations	2.76%

Facility Level Information	
Nameplate Capacity	**291.27 MWDC**
Number of modules	844272
Nameplate Capacity	**220.00 MWAC**
Number of arrays	44
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	230 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	NSRDB PSMv3
GHI	1903.4 kWh/m2
DHI	kWh/m2
Global POA	2556.6 kWh/m2
Average Temp.	9.92 °C
Average Temp. (Generation)	14.91 °C
Average Wind	2.11 m/s
Average Wind (Generation)	2.82 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Rock Springs, Wyoming
Latitude (N):	41.6 °
Longitude (W):	-109 °
Altitude	2055 m
ASHRAE Cooling DB Temp.	29.8 °C
ASHRAE Extreme Mean Min. Temp.	-25.1 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	12343.3 MWh
AC capacity factor - Inv Rating	28.18%
AC capacity factor - POI Rating	28.18%
DC capacity factor	21.29%
Specific Production	1865 kWh/kWp/yr
Performance Ratio PR	82.17%
Night time losses	-20.0 MWh
Plant Output Limitations	0.00%

Facility Level Information	
Nameplate Capacity	**6.62 MWDC**
Number of modules	19188
Nameplate Capacity	**5.00 MWAC**
Number of arrays	1
Interconnection Limit	**5.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.324

Weather	
Source	TMY3
GHI	1693.5 kWh/m2
DHI	kWh/m2
Global POA	2269.3 kWh/m2
Average Temp.	6.49 °C
Average Temp. (Generation)	10.35 °C
Average Wind	4.81 m/s
Average Wind (Generation)	5.32 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	0.70%
HV transformer no-load losses	0.00%
HV transformer full load losses	0.00%
HV line	0.00%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Rock Springs, Wyoming
Latitude (N):	41.6 °
Longitude (W):	-109 °
Altitude	2055 m
ASHRAE Cooling DB Temp.	29.8 °C
ASHRAE Extreme Mean Min. Temp.	-25.1 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	131702.0 MWh
AC capacity factor - Inv Rating	27.34%
AC capacity factor - POI Rating	30.07%
DC capacity factor	20.65%
Specific Production	1809 kWh/kWp/yr
Performance Ratio PR	79.70%
Night time losses	-387.3 MWh
Plant Output Limitations	2.04%

Facility Level Information	
Nameplate Capacity	**72.82 MWDC**
Number of modules	211068
Nameplate Capacity	**55.00 MWAC**
Number of arrays	11
Interconnection Limit	**50.00 MWAC**
Inteconnection Voltage	115 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1693.5 kWh/m2
DHI	kWh/m2
Global POA	2269.3 kWh/m2
Average Temp.	6.49 °C
Average Temp. (Generation)	10.35 °C
Average Wind	4.81 m/s
Average Wind (Generation)	5.32 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC2 Date: 31-Aug-18

Site Information	
City / State:	Rock Springs, Wyoming
Latitude (N):	41.6 °
Longitude (W):	-109 °
Altitude	2055 m
ASHRAE Cooling DB Temp.	29.8 °C
ASHRAE Extreme Mean Min. Temp.	-25.1 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.2 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	526808.1 MWh
AC capacity factor - Inv Rating	27.34%
AC capacity factor - POI Rating	30.07%
DC capacity factor	20.65%
Specific Production	1809 kWh/kWp/yr
Performance Ratio PR	79.70%
Night time losses	-1549.3 MWh
Plant Output Limitations	2.04%

Facility Level Information	
Nameplate Capacity	**291.27 MWDC**
Number of modules	844272
Nameplate Capacity	**220.00 MWAC**
Number of arrays	44
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	230 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1693.5 kWh/m2
DHI	kWh/m2
Global POA	2269.3 kWh/m2
Average Temp.	6.49 °C
Average Temp. (Generation)	10.35 °C
Average Wind	4.81 m/s
Average Wind (Generation)	5.32 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 31-Aug-18

Site Information	
City / State:	Yakima, WA
Latitude (N):	46.6 °
Longitude (W):	-120.5 °
Altitude	324 m
ASHRAE Cooling DB Temp.	34.1 °C
ASHRAE Extreme Mean Min. Temp.	-17 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	10609.2 MWh
AC capacity factor - Inv Rating	24.22%
AC capacity factor - POI Rating	24.22%
DC capacity factor	18.29%
Specific Production	1603 kWh/kWp/yr
Performance Ratio PR	81.56%
Night time losses	-20.1 MWh
Plant Output Limitations	0.00%

Facility Level Information	
Nameplate Capacity	**6.62 MWDC**
Number of modules	19188
Nameplate Capacity	**5.00 MWAC**
Number of arrays	1
Interconnection Limit	**5.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.324

Weather	
Source	TMY3
GHI	1486.8 kWh/m2
DHI	kWh/m2
Global POA	1964.9 kWh/m2
Average Temp.	9.97 °C
Average Temp. (Generation)	14.53 °C
Average Wind	3.17 m/s
Average Wind (Generation)	3.30 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	0.70%
HV transformer no-load losses	0.00%
HV transformer full load losses	0.00%
HV line	0.00%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 31-Aug-18

Site Information	
City / State:	Yakima, WA
Latitude (N):	46.6 °
Longitude (W):	-120.5 °
Altitude	324 m
ASHRAE Cooling DB Temp.	34.1 °C
ASHRAE Extreme Mean Min. Temp.	-17 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	114064.6 MWh
AC capacity factor - Inv Rating	23.67%
AC capacity factor - POI Rating	26.04%
DC capacity factor	17.88%
Specific Production	1566 kWh/kWp/yr
Performance Ratio PR	79.72%
Night time losses	-389.2 MWh
Plant Output Limitations	1.32%

Facility Level Information	
Nameplate Capacity	**72.82 MWDC**
Number of modules	211068
Nameplate Capacity	**55.00 MWAC**
Number of arrays	11
Interconnection Limit	**50.00 MWAC**
Inteconnection Voltage	115 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1486.8 kWh/m2
DHI	kWh/m2
Global POA	1964.9 kWh/m2
Average Temp.	9.97 °C
Average Temp. (Generation)	14.53 °C
Average Wind	3.17 m/s
Average Wind (Generation)	3.30 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2018 Renewables Technology Assessment**

Variant: VC3 Date: 31-Aug-18

Site Information	
City / State:	Yakima, WA
Latitude (N):	46.6 °
Longitude (W):	-120.5 °
Altitude	324 m
ASHRAE Cooling DB Temp.	34.1 °C
ASHRAE Extreme Mean Min. Temp.	-17 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	36 %
Row spacing	5.5 m
Mounting	Tracker
Tilt angle or rotation limits	60 °
Azimuth	0 °
Tracking strategy	TRUE
Availability	100.0 %
Degradation	0.5 %/yr

Array Level Information	
Module rating	345 W
# Modules per string	26
Strings in parallel	738
Total number of modules	19188
DC capacity	6620 kW
Inverter rating	5000 kW
DC/AC ratio - Inv Rating	1.324

PVsyst Input Parameters	
Transposition model	Perez
Constant thermal loss factor (Uc)	25.0 W/m2-K
Wind loss factor (Uv)	1.2 W/m2-K/m/s
Soiling losses	2.4 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.4 %
Module mismatch loss	1.0 %
DC health loss	1.0 %

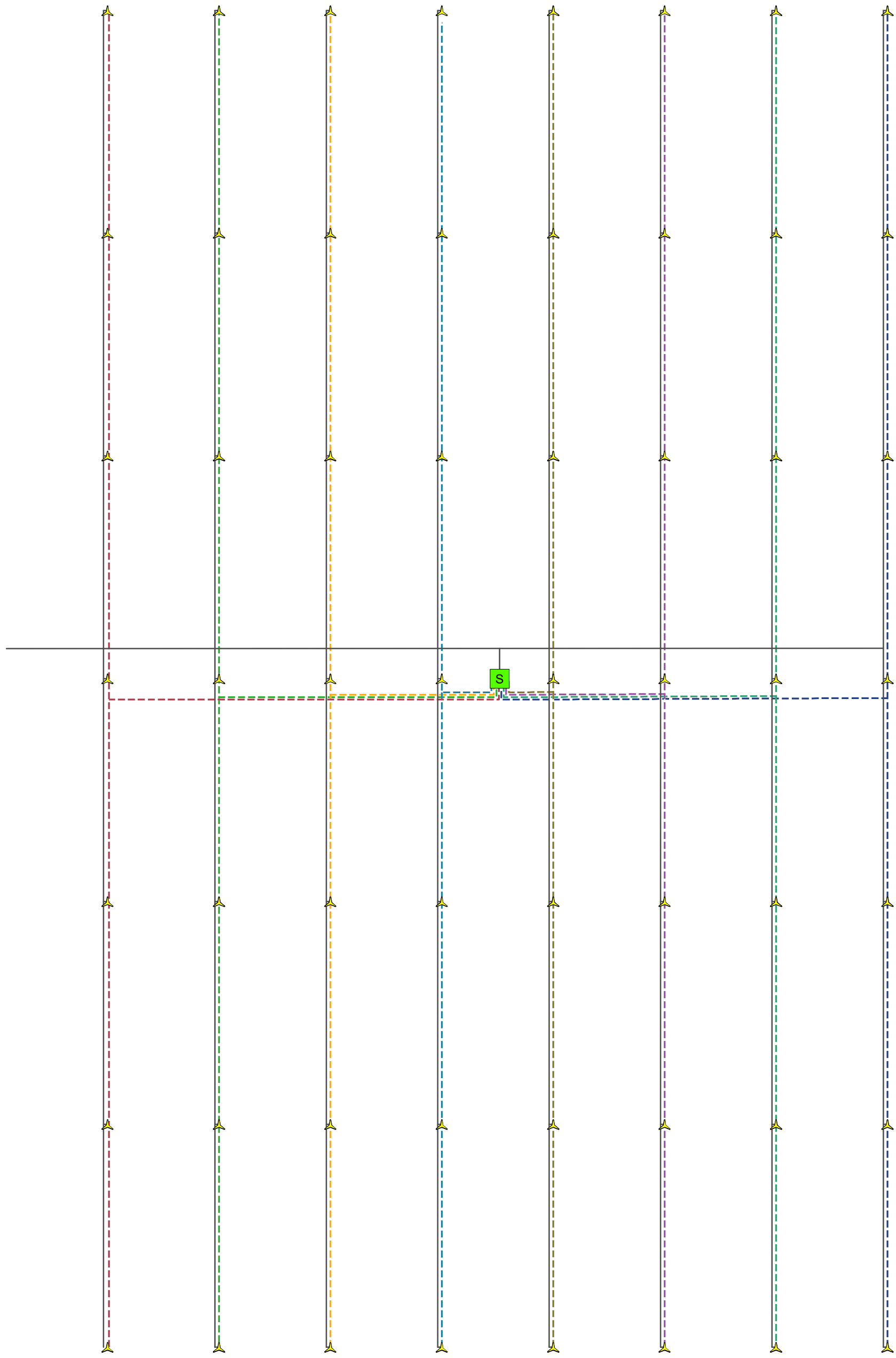
Estimated Annual Energy Production	
P50 net production (yr-1)	456258.5 MWh
AC capacity factor - Inv Rating	23.67%
AC capacity factor - POI Rating	26.04%
DC capacity factor	17.88%
Specific Production	1566 kWh/kWp/yr
Performance Ratio PR	79.72%
Night time losses	-1556.8 MWh
Plant Output Limitations	1.32%

Facility Level Information	
Nameplate Capacity	**291.27 MWDC**
Number of modules	844272
Nameplate Capacity	**220.00 MWAC**
Number of arrays	44
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	230 kV
DC/AC ratio - POI Rating	1.456

Weather	
Source	TMY3
GHI	1486.8 kWh/m2
DHI	kWh/m2
Global POA	1964.9 kWh/m2
Average Temp.	9.97 °C
Average Temp. (Generation)	14.53 °C
Average Wind	3.17 m/s
Average Wind (Generation)	3.30 m/s

AC System Losses	
MV transformer no-load losses	0.07%
MV transformer full load losses	0.85%
MV collection system	1.30%
HV transformer no-load losses	0.07%
HV transformer full load losses	0.48%
HV line	0.05%
Auxiliary	0.01%

APPENDIX D – WIND PERFORMANCE INFORMATION



Drawing Notes:
1. Layout is intended to be generic / conceptual and not necessarily representative of a site that would be constructed. Layout based upon generic turbine model with approx. 414m by 828m gridded spacing. Final turbine model, project size, and site conditions will alter layout.

PRELIMINARY
NOT FOR CONSTRUCTION

LEGEND

- Proposed Turbine
- Collector Substation
- Access Roads
- Circuit 1
- Circuit 2
- Circuit 3
- Circuit 4
- Circuit 5
- Circuit 6
- Circuit 7
- Circuit 8

REFERENCE

0 500 1,000
Feet

0 100 200
Meters

N

GENERIC SITE LAYOUT
200 MW Wind Farm

LOCATION:	Generic
CLIENT:	Pacificorp
PROJ. NO.:	109571
CREATED:	09/06/2018

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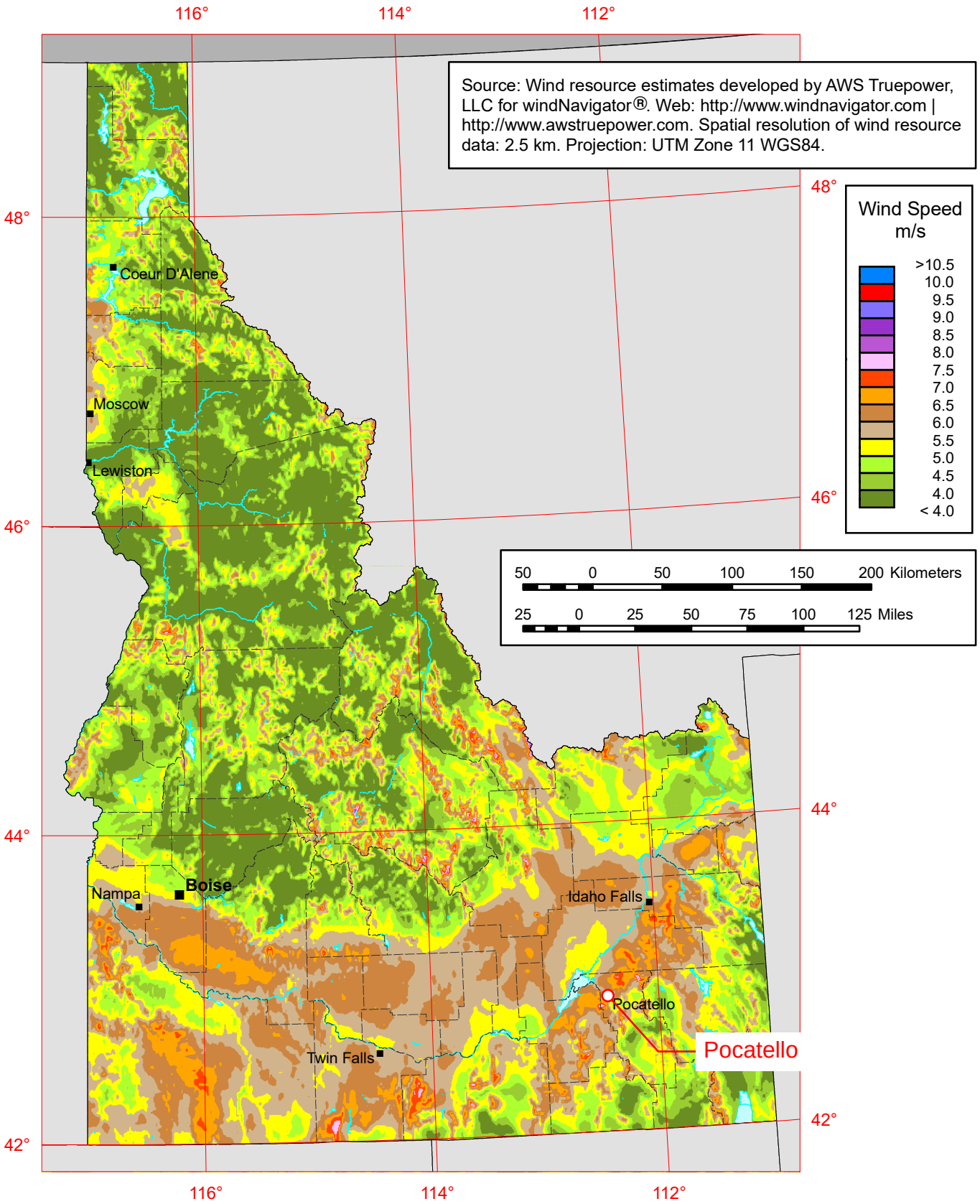
Idaho - Annual Average Wind Speed at 80 m



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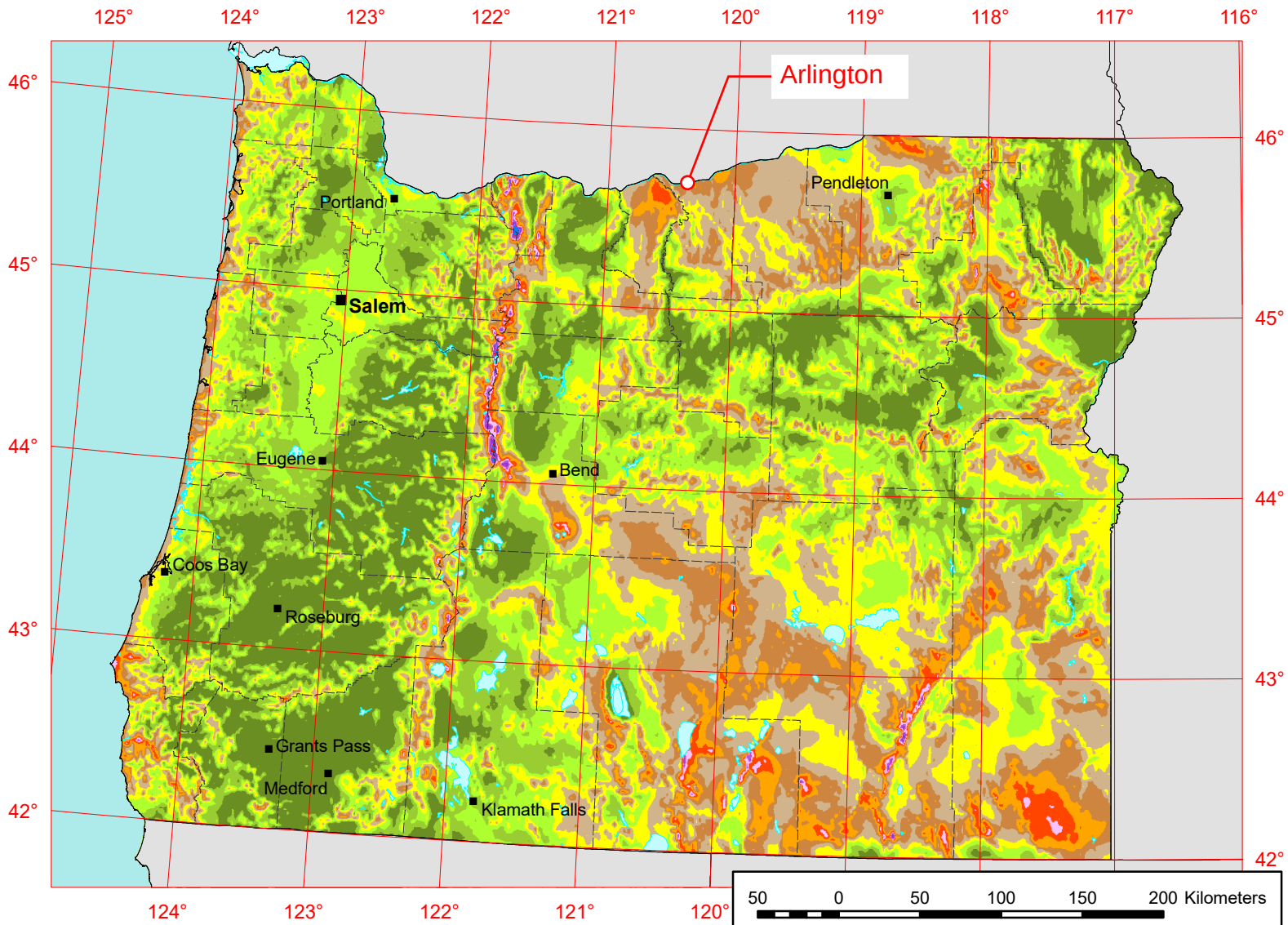
06-OCT-2010 1.1.1

Oregon - Annual Average Wind Speed at 80 m



Wind Speed m/s

- >10.5
- 10.0
- 9.5
- 9.0
- 8.5
- 8.0
- 7.5
- 7.0
- 6.5
- 6.0
- 5.5
- 5.0
- 4.5
- 4.0
- < 4.0

Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 11 WGS84.

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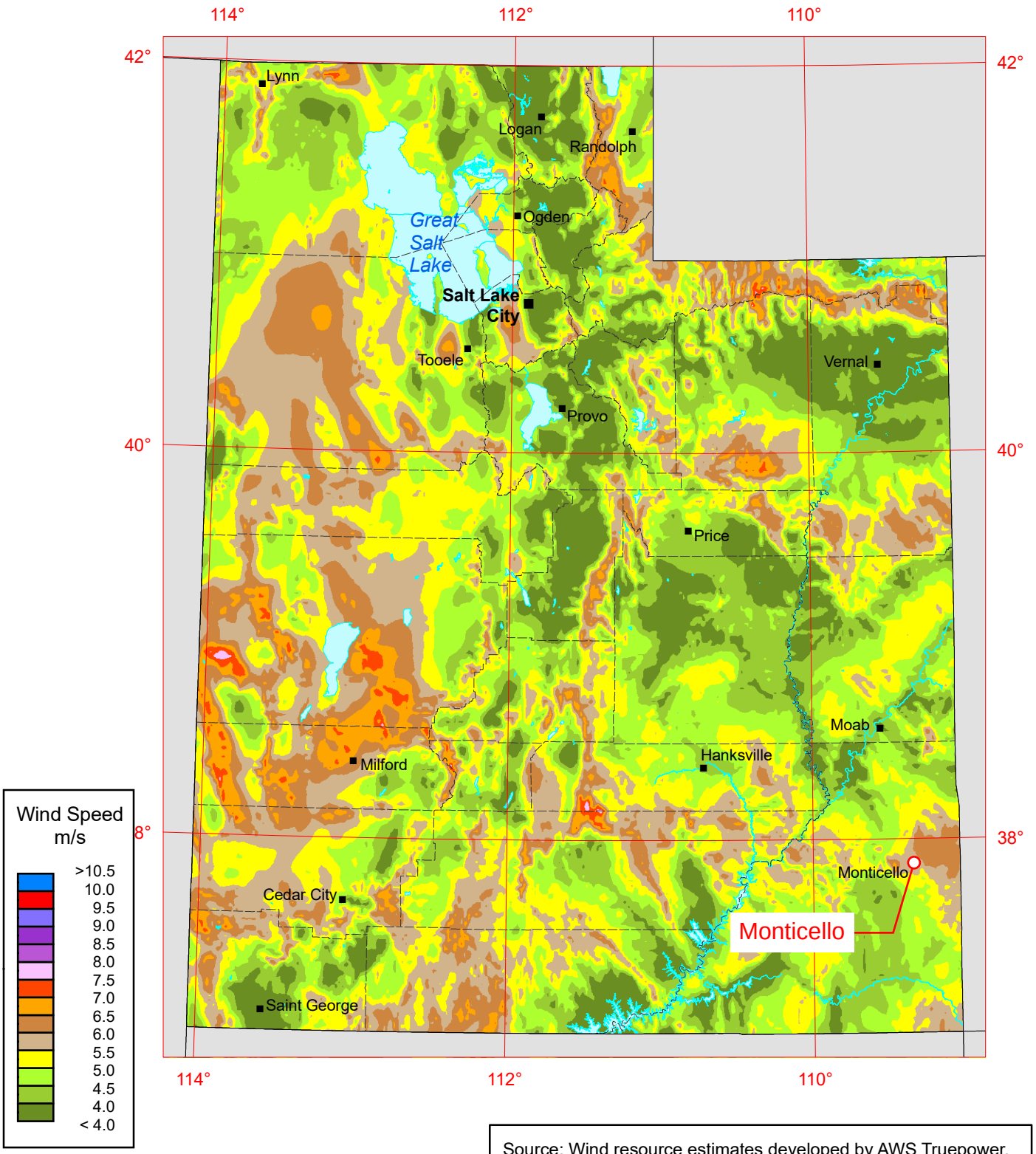
05-OCT-2010 1.1.1

Utah - Annual Average Wind Speed at 80 m



Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 12 WGS84.

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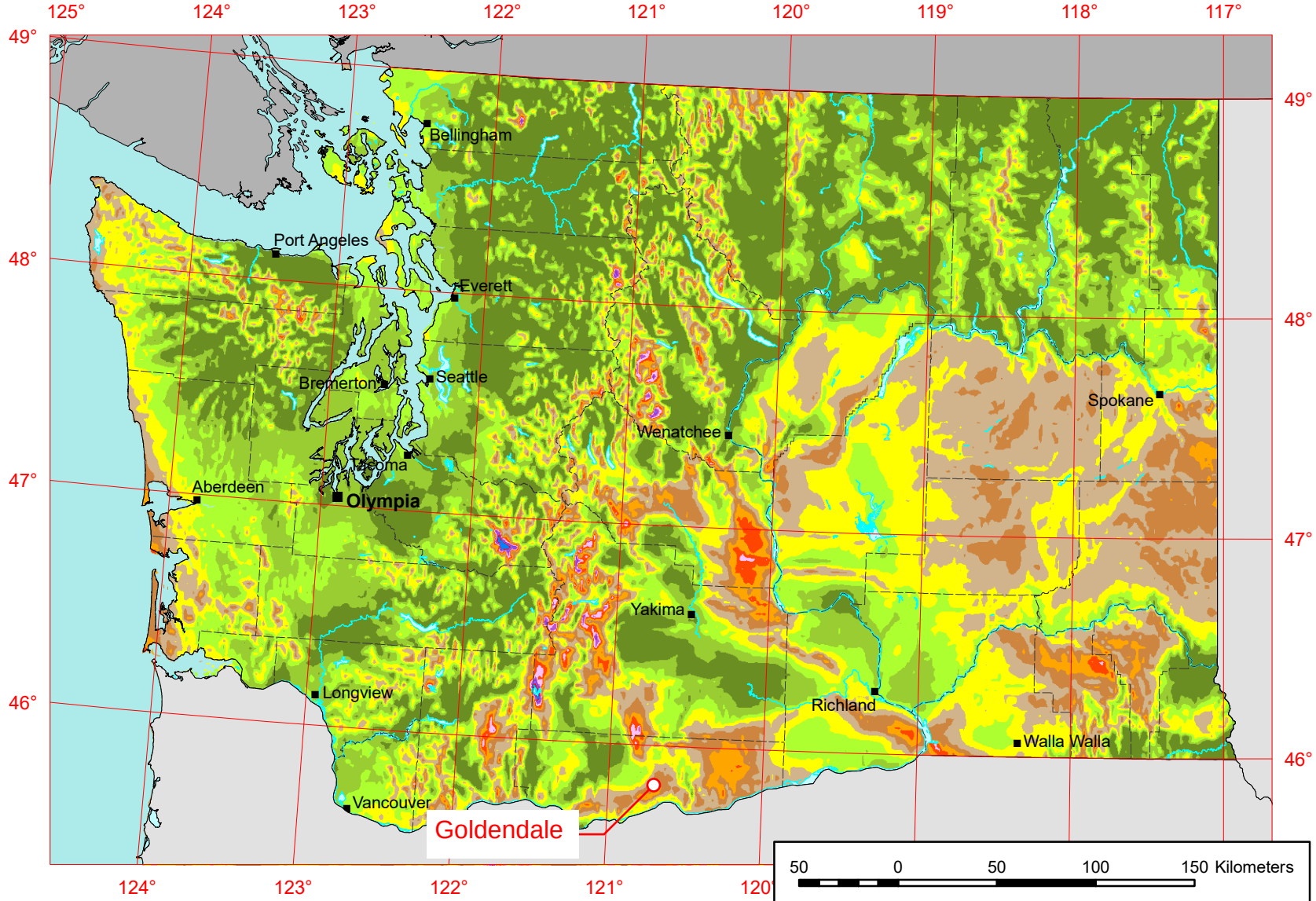
29-SEP-2010 1.1.1

Washington - Annual Average Wind Speed at 80 m



Wind Speed m/s

- >10.5
- 10.0
- 9.5
- 9.0
- 8.5
- 8.0
- 7.5
- 7.0
- 6.5
- 6.0
- 5.5
- 5.0
- 4.5
- 4.0
- < 4.0

50 0 50 100 150 Kilometers

25 0 25 50 75 100 Miles

Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 11 WGS84.

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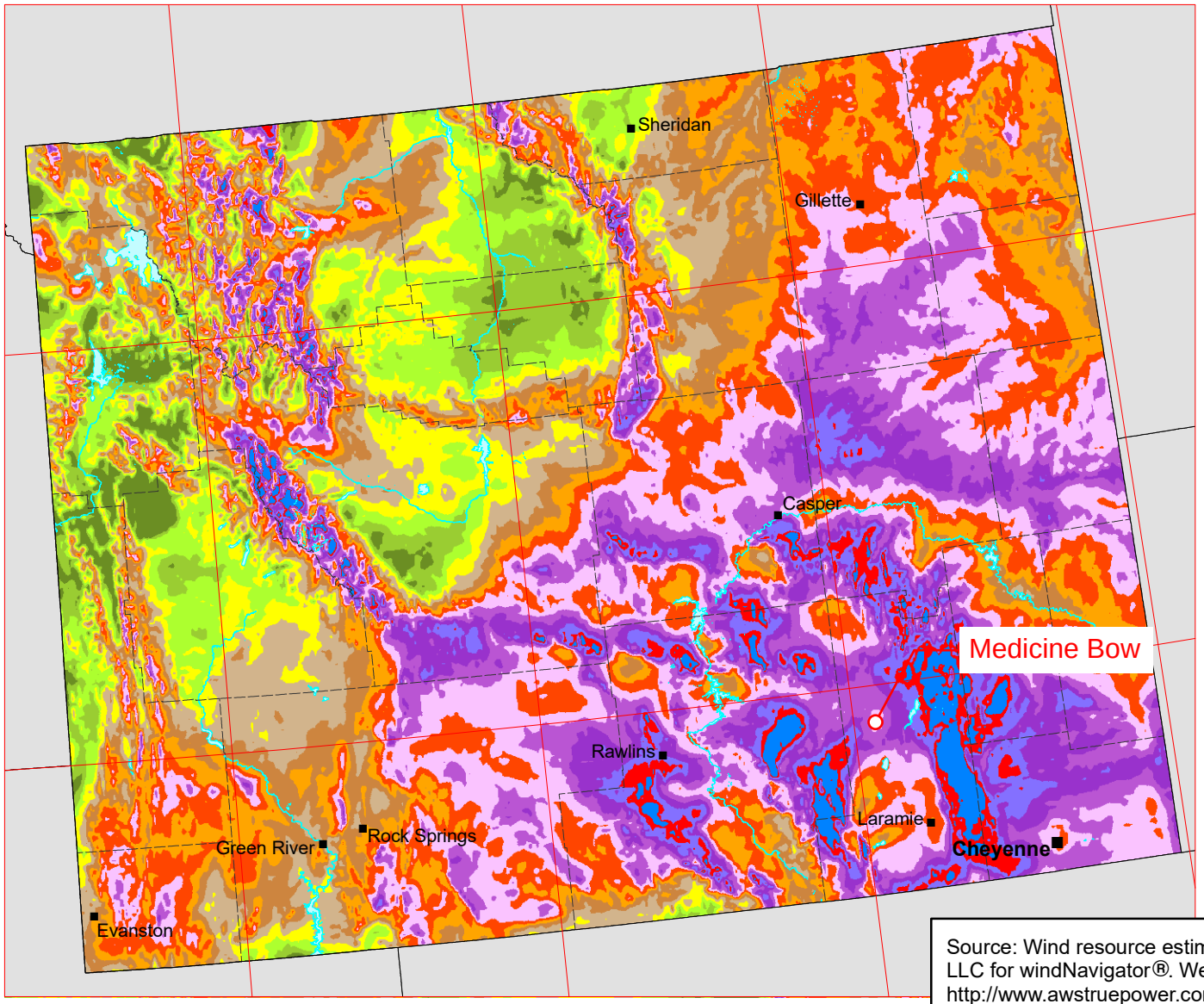
05-OCT-2010 1.1.1

Wyoming Annual Average Wind Speed at 80 m



Wind Speed m/s

- >10.5
- 10.0
- 9.5
- 9.0
- 8.5
- 8.0
- 7.5
- 7.0
- 6.5
- 6.0
- 5.5
- 5.0
- 4.5
- 4.0
- < 4.0

Source: Wind resource estimates developed by AWS Truepower, LLC for windNavigator®. Web: http://www.windnavigator.com | http://www.awstruepower.com. Spatial resolution of wind resource data: 2.5 km. Projection: UTM Zone 11 WGS84.

50 0 50 100 150 200 Kilometers

25 0 25 50 75 100 125 Miles

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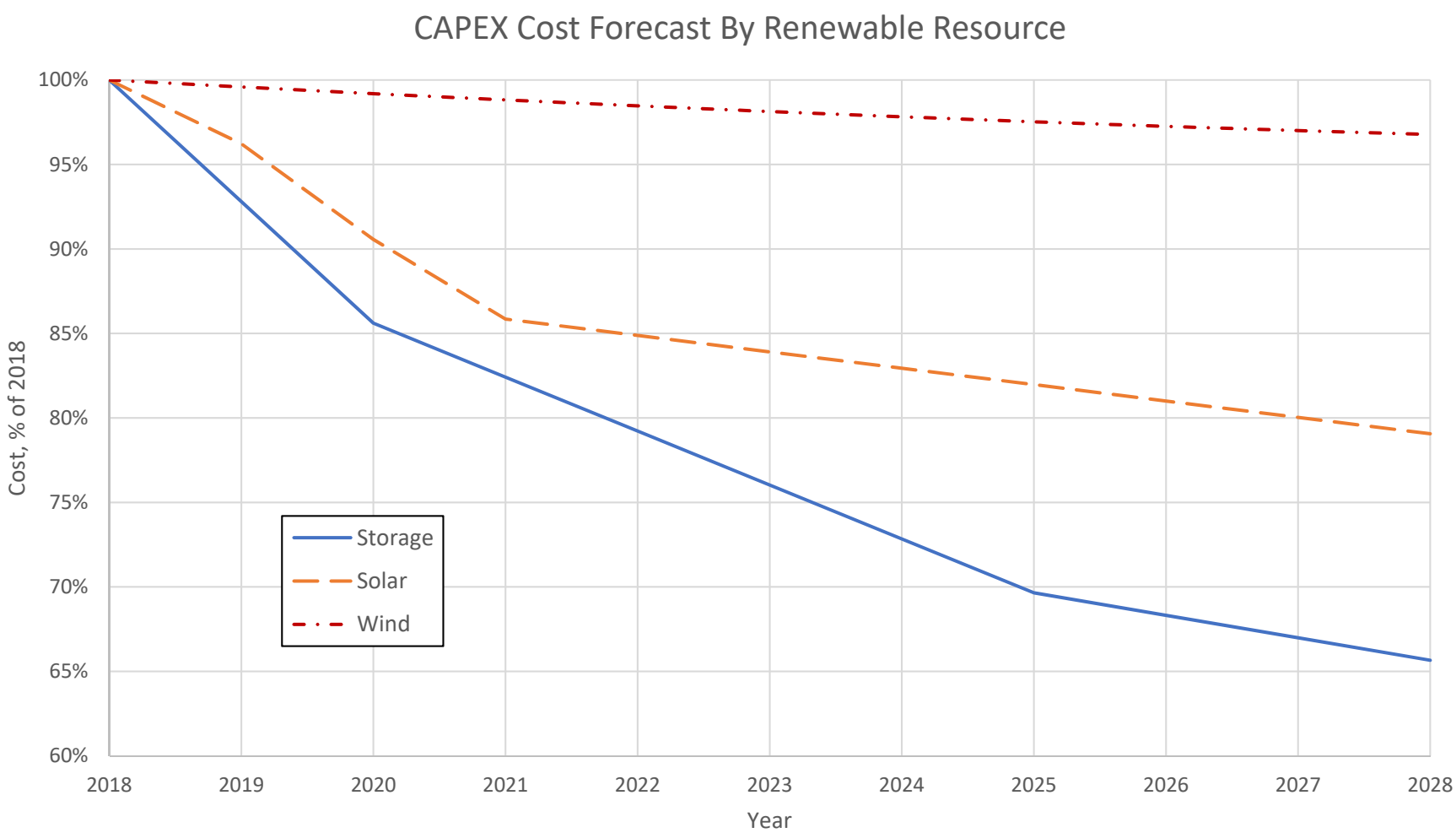
07-OCT-2010 1.1.1

APPENDIX E – DECLINING COST CURVES



Notes:

1. The declining cost curve for onshore wind was developed using NREL Techno-Resource Group (TRG) mid CAPEX cost inforamtion. The cost for TRG 4 - TRG 8 were averaged which represent the Pacificorp identified sites.
2. The declining cost curve for utility solar photovoltaic was developed using NREL mid CAPEX cost inforamtion. From the inforamation provided, the costs for Seattle, Los Angeles, and Daggett were averaged.
3. The declining cost curve for battery storage was developed using NREL mid CAPEX cost information for an 8-hour storage device with 15-year life and 90% round-trip efficiency. Linear interpolation was used between NREL provided data points.

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APPENDIX Q – ENERGY STORAGE POTENTIAL EVALUATION

Introduction

Energy storage resources can provide a wide range of grid services and can be flexibly sized and sited. Many of these grid services have been increasing in value with increasing penetration of variable energy resources such as wind and solar, while energy storage costs have been falling. As a result, storage resources are an increasing component of PacifiCorp's least-cost, least-risk preferred portfolio. While the 2019 IRP portfolio analysis captures the system benefits of energy storage, it does not fully account for localized benefits and siting opportunities. This appendix provides details on how energy storage resources can be configured to maximize the benefits they provide.

Because energy storage resources are highly flexible, with the ability to respond to dispatch signals and act as both a load and a resource, they can potentially provide any of the grid services discussed herein. Other types of resources, including distributed generation, energy efficiency, and interruptible loads can also provide one or more of these grid services, and can complement or provide lower-cost alternatives to energy storage. Given that broad applicability, Part 1 of this appendix first discusses a variety of grid services as generically and broadly as possible. Part 2 discusses the key operating parameters of energy storage and how those operating parameters relate to the grid services in Part 1. Finally, Part 3 discusses how to optimize the configuration and dispatch of energy storage and other distributed resources to maximize the benefits to the local grid and the system. Part 3 also provides examples of specific applications and examples of applications that may be cost-effective in the future.

Part 1: Grid Services

PacifiCorp must ensure that sufficient energy is generated to meet retail customer demand at all times. It also must maintain resources that can respond to changing system conditions at short notice, these operating reserves are held in accordance with reliability standards established by the National Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC). Both energy and operating reserves are dispatch-based, and dependent on the specific conditions at a specific place and time. These values are generally independent from hour to hour, as removing a resource in a subset of hours may not impact the value in the remaining hours.

Because load can be higher than expected and some resources may be unavailable at any given time, sufficient generation resources are needed to ensure that energy and operating reserve requirements can be met with a high degree of confidence. This is referred to as generation capacity. The transfer of energy from the locations where it is generated to the locations where it is delivered to customers requires poles, wires, and transformers, and the capability of these assets is referred to as transmission and distribution (T&D) capacity. Generation and T&D capacity are both generally asset-based, and provide value by allowing changes in the resources and T&D elements. In general, assets cannot be avoided based on changes to a subset of the hours in which they are needed and only limited changes are possible once constructed or contracted. It should

also be noted that the impact of asset or capacity changes on dispatch must also be included in any valuation.

These obligations are broken down into the following grid services, which are discussed in this section:

- Energy, including losses;
- Operating reserves, including:
    - Spinning reserve;
    - Non-spinning reserve;
    - Regulation and load following reserves; and
    - Frequency response;
- Transmission and distribution capacity; and
- Generation capacity.

Energy Value

Background

Because PacifiCorp's load and resources must be balanced at all times, when an increment of generation is added to PacifiCorp's system, an increment of generation must also be removed. This could take the form of a generator that is backed down, an avoided market purchase, or an additional market sale. The cost of the increment that is removed (or the revenue from the sale), represents the energy value, and this value varies by location and by time. Location can also impact losses relative to the generation which would otherwise have been dispatched, with losses manifesting as a larger effective volume. With regard to time, there are two relevant time scales: hourly values, and sub-hourly values.

The energy value in a location is dependent on PacifiCorp's load and resource balance, the dispatch cost of its resources, and the transmission capability connecting those resources to load. Differences in energy value occur when the economic resources in area exceed the transmission export capability to an area that must then use higher cost resources to serve load. Once transmission is fully utilized, the higher cost resources must be deployed to serve the importing area and lower cost resources will be available in the exporting area. As a result, the value in each location will reflect the marginal resources used to serve load in each area. If transfers are not fully utilized in either direction, the marginal resource in both areas would be the same, and the energy value would be the same.

Both load and resource availability change significantly across the day and across the year. Differences in value over time are driven by the cost of the marginal resource needed to serve load, which changes when load or resource availability change. When load goes up, or the supply of lower-cost resources goes down, the marginal resource needed to serve load will be more expensive.

The value by location is also dependent on the losses relative to the generation which would otherwise have been dispatched. Losses occur during the transfer of energy across the T&D system to a customer's location. As distance and voltage transformation increase, more generation must be injected to meet a customer's demand. As a result, a distributed resource that is close to customer load or located on the same voltage level can avoid both energy at its location as well as the losses which otherwise would have occurred in delivering energy to that location. As a result,

the marginal generation resource's output may be reduced by an amount greater than the metered output of a distributed resource. This increase in volume due to losses is also relevant to generation and T&D capacity value. In addition to varying by location and voltage, losses vary across time, primarily due to line loading, as loss rates increase as loading increases. To the extent distributed resources impact line loading, it is reasonable to incorporate the marginal losses that they avoid.

Modeling

There are two basic sources of energy values: market price forecasts and production cost models. There are also two relevant time scales: hourly values, and sub-hourly values.

PacifiCorp produces a non-confidential official forward price curve (OFPC) for the major market points in which it typically transacts on a quarterly basis. The OFPC represents the price at which power would be transacted today, for delivery in a future period. The OFPC contains prices for each month for heavy load hour (HLH) and light load hour (LLH) periods and goes forward approximately 20 years.[1] However, not all hours in the HLH or LLH periods have equal value. To differentiate between hours, PacifiCorp uses scalars calculated based on historical hourly results. For PacifiCorp's operations and production cost modeling, scalars are based on the California Independent System Operator's day-ahead hourly market prices. Because these values are used in operations, the details on the methodology and the resulting prices are treated confidentially. To allow for transparency, PacifiCorp has also developed non-confidential scalars using historical Energy Imbalance Market prices. With either scalars, the result is a forecast of hourly market prices that averages to the values in the OFPC over the course of a month. Using hourly market price to calculate energy value implies that market transactions are either the avoided resource, or a reasonable representation of the avoided resource's cost.

Production cost models contain a representation of an electric power system, including its load, resources, and transmission rights, as well as markets where power can be bought or sold. They also account for operating reserve obligations and the resources held to cover those obligations. All models are simplified representations, and there are several key simplifying assumptions. The granularity of a model is its smallest calculated timestep. While calculating twice as many timesteps should take roughly twice as long from a mechanical standpoint, maintaining inputs to represent those timesteps is more complicated, and a model is only as good as its inputs. To simplify the representation of location, transmission areas can be defined by the key transmission constraints which separate them, with transmission within each area assumed to be unconstrained. Another simplifying assumption is to model all load and resources at a level equivalent to generator input. For instance, load is "grossed up" from the metered volume to a level that includes the estimated losses necessary to serve it. This allows for a one for one relationship between all volumes, which vastly simplifies the model.

PacifiCorp's production cost models with these representations include the Planning and Risk (PaR) model, used to evaluate portfolios in the IRP, and the Generation and Regulation Initiative Decision Tools model (GRID), used to calculate net power costs in general rate cases and for some qualifying facility avoided cost rates. Both of these models reflect the system down to an hourly granularity. While these production cost models use the hourly market prices from the OFPC, a distributed resource's energy value in these models will depend on its location and other

[1] HLH is 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays. LLH is all other hours.

characteristics and can be either higher or lower than the market price in a given hour. Generally, a resource's value is based on the difference between two production cost model studies: one with the resource included, and one with the resource excluded. This explicitly identifies the marginal resources dispatched in the absence of the resource being evaluated.

More detailed models of the electrical power system also exist, for instance PacifiCorp uses physical models for grid operations and planning that account for power flows and the loading of individual system elements. Similarly, the California Independent System Operator (CAISO) uses a "Full Network Model" with detailed representations of all resources and loads, as well as the transmission system. CAISO's model includes a representation of PacifiCorp's system for the purpose of dispatching resources in the Western Energy Imbalance Market (EIM), and models a five minute granularity for that purpose. The added detail these physical models produce comes from a significant increase in the complexity of inputs and computational requirements.

Hourly market prices can be used to provide a readily available estimate of energy value, as shown in Table Q.1 for various energy storage technologies. The variables which impact energy margin include: hours of storage, efficiency, forced outage rates, and variable degradation costs. Table Q.1 contains twenty-year nominal levelized values for 2019-2038, and reflects an average of the margins at the Mid-Columbia and Four Corners markets.

Table Q.1 - Energy Margin by Energy Storage Technology

Technology	Hours of Storage	Efficiency (%)	Forced Outage (%)	Variable Cost ($/MWh)	Energy Margin ($/kw-yr)
Lithium Ion	2	88%	1%	12.48	32.13
Lithium Ion	4	88%	1%	12.48	49.77
Flow	6	65%	2%	0	53.03
Pumped Hydro	9	79%	3%	0	81.67

These market values do not account for the effects of location, volume, or operating reserve requirements. For instance, PacifiCorp is obligated to hold contingency reserves equal to three percent of all generation in its balancing authority areas, but is not required to hold those reserves for market purchases. This is analogous to the additional regulation reserves held to account for the variability and uncertainty in the output of wind and solar (a.k.a. integration costs). Adjustments can be applied to account for these differences, but the results are likely to diverge as market prices and resource portfolios change. Hourly market prices are also more likely to understate the value of dispatchable resources.

The PaR model and the GRID model both identify resources to carry operating reserves for each hour, but do not include the intra-hour changes that would cause those resources to be deployed. Because resources that are dispatchable within the hour can be dispatched up when marginal energy costs are high, and down when marginal energy costs are low, this can result in incremental value relative to an hourly market price or hourly production cost model result. In practice, sub-hourly dispatch benefits are largely derived from PacifiCorp's participation in EIM, and the specific rules associated with that market. For instance, resources must be participating in EIM in order to receive settlement payments based on their five-minute dispatches. Resources that are not participating receive settlement payments based on their hourly imbalance. Because non-participating resources are not visible to the market, their sub-hourly dispatch would not impact

the market solution. Because distributed resources can be aggregated for purposes of EIM participation, size should not be an impediment; however, the structure of the EIM may dictate some aspects of their use and would need to be aligned with the other services a distributed resource provides.

To help identify sub-hourly energy value not captured in its hourly production cost models, during the development of the 2019 IRP, PacifiCorp calculated intra-hour flexible resource credits (IHFRC) for a variety of resource types, based on expected economic dispatch relative to historical EIM sub-hourly pricing. Unsurprisingly given their flexibility, energy storage resources provide the highest value of the resources evaluated, as shown in Table Q.2 below. Values shown are in 2018$.

Table Q.2 – Intra-hour Flexible Resource Credits by Resource Type

Resource	Credit ($/kw-year)	Dispatch (% of Nameplate)	Cycles/day	Source
Pumped Hydro 6-14hr	30.44	9.2% - 9.8%	0.2 - 0.4	Proxy
CAES 48hr	30.28	11%	0.05	Proxy
Flow 6hr	27.24	10%	0.38	Proxy
Li-Ion 4hr	25.60	9%	0.56	Proxy
Li-Ion 2hr	25.02	8%	0.90	Proxy
Load Control - 528 hrs/yr	19.20	6%	n/a	Proxy
Load Control - 30 hrs/yr	6.00	0.3%	n/a	Proxy
Resource			**Minimum operating level (%)**	
SCCT Intercooled	18.51	8%	15%	Proxy
SCCT Aero	16.58	10%	40%	Proxy
Baseload Steam	5.54	*	24%	Actual
Peak Steam	4.89	*	24%	Actual
CCCT	3.77	*	70%	Actual
SCCT Frame F	3.47	1%	43%	Proxy
Resource/Bid Price			**% of annual output**	
Solar/$0	1.22	-1.7%	5.6%	Proxy
Wind/$0	0.87	-1.1%	2.9%	Proxy
Wind/PTC	0.14	-0.04%	0.1%	Proxy

*Resources are dispatched up and down from base schedule in EIM.

PacifiCorp initially proposed that IHFRC values be netted out of the resource costs identified in its supply-side resource table, such that the net costs would be used for portfolio selection and valuation. In response to stakeholder feedback about the concept and methodology, the adjustment for IHFRC values was not incorporated as part of the 2019 IRP. PacifiCorp anticipates that the resources above would generate incremental value relative to the hourly granularity of the 2019 IRP modeling, but additional work is required to engage stakeholders and ensure that the results are truly additional.

Operating Reserve Value

Background

Operating reserve is defined by NERC as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local

area protection."[2] Operating reserves are capability that is not currently providing energy, but which can be called upon at short notice in response to changes in load or resources. Operating reserves and energy are additive – a resource can provide both at the same time, but not with the same increment of its generating capability. Operating reserves can also be provided by interruptible loads, which have an effect comparable to incremental resources. Additional details on operating reserve requirements are provided in Volume II, Appendix F (Flexible Reserve Study).

As with energy value, operating reserve value is based on the marginal resource that would otherwise supply operating reserves, and varies by both location, time, and the speed of the response. Because operating reserve requirements are primarily applied at the Balancing Authority Area (BAA) level, the associated value is typically uniform within each of PacifiCorp's BAAs. An exception to this is that operating reserves must be deliverable to balance load or resources, so unused capability in a constrained bubble without additional export capability does not count toward the meeting the requirements. Operating reserve value is somewhat indirect in comparison to energy value, as it relates to the use of the freed up capacity on units that would otherwise be holding reserves. If that resource's incremental energy is less expensive that what is currently dispatched, it can be dispatched up, and more expensive energy can be dispatched down. The value of the operating reserves in that instance is the margin between the freed up energy and the resource that is dispatched down. Note that the dispatch price of the resource being evaluated does not impact the value, since holding operating reserves does not require dispatch. When the freed up resource is more expensive than what is currently dispatched, it will not generate more when the operating reserve requirement is removed, and the value of operating reserves would be zero. With this in mind, operating reserves are generally held on the resources with the highest dispatch price. Finally, operating reserve value is limited by the speed of the response: how fast a unit can ramp up in a specified time period, and how soon it begins to respond after receiving a dispatch signal. Reliability standards require a range of operating reserve types, with response times ranging from seconds to thirty minutes.

Modeling

As discussed above, the value of incremental operating reserves is equal to the positive margin between the dispatch cost of the lowest cost resource that was being held for reserve, and the dispatch cost of the highest cost resource that was dispatched for energy. Similar to the value of energy, the price of different operating reserve types could be forecasted by hour, based on forecasts of reserve capability, demand, and resource dispatch costs. Given the range and variability in these components, this would be an involved calculation. In addition, because operating reserves are a small fraction of load, they are more sensitive to volume than energy. For instance, spinning reserve obligations are approximately three percent of load in each hour. As a result, resource additions may rapidly cover that portion of PacifiCorp's requirement met by resources that could otherwise provide economic generation and which produce a margin when released from reserve holding. This is particularly true for batteries and interruptible load resources that can respond rapidly and thus count all or most of their output toward reserve obligations.

While a market price for operating reserve products does not align well with PacifiCorp's system, the specifics of the calculation described above are embedded within PacifiCorp's production cost models. Those models allocate reserves first to energy limited resources in those periods where

[2] NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf, updated May 13, 2019.

they could generate, but are not scheduled to do so. Examples of energy limited resources include interruptible loads, hydro, and energy storage. If called on for reserves, these resources would lose the ability to generate in a different period, so the net effect on energy value for that resource is relatively small. As a result, the unused capacity on these resources can't be used for generation, but that also means it can count as reserves without forgoing any generation and incurring a cost to do so. After operating reserves have been fully allocated to the available energy-limited resources, reserves are allocated to the highest cost generators with reserve capability in the supply stack, up to each unit's reserve capability, until the entire requirement is met. This is generally done prior to generation dispatch and balancing, because the requirements are input to the model or based on a formula and aren't typically restricted based on transmission availability. After the reserve allocations are complete, the remaining dispatch capability of each unit is used to develop an optimized balance of load and resources.

As part of the calculation of wind and solar integration costs for the 2019 IRP, as reported in Volume II, Appendix F (Flexible Reserve Study), PacifiCorp prepared a study assessing the cost of holding incremental operating reserves. That study identified a cost of $50/kw-yr (2018$), based on a 2018-2036 study period. This value would be applicable to any resource that provided operating reserves uniformly throughout the year.

Transmission and Distribution Capacity

For the first time, the 2019 IRP has endogenously included transmission upgrades as part of portfolio selection. This allows the cost of transmission upgrades to be considered as part of the modeled cost of resources in each area. However, energy efficiency, load control, and stand-alone energy storage resources were not subject to these constraints, placing them at an advantage relative to both thermal and renewable resource options. In addition, while the cost of specific T&D projects varies, a generic system wide estimate of transmission upgrade costs is included as a credit to energy efficiency in the 2019 IRP, and amounts to $4.16/kw-year (2018$). In practice, these costs would vary by project and some transmission upgrades would not be suitable for deferral by distributed resources. Because of the large scale of many transmission upgrades, and the binary nature of the expenditures, it may be difficult to procure adequate distributed resources to cover the need in a timely fashion and in accordance with reliability requirements, though it is always appropriate to consider the available options when considering expenditures on an upgrade. Distribution capacity upgrades are more likely to be suitable for deferral by a distributed resource, as the scale of the need is closer to that of these types of resources.

To that end, PacifiCorp maintains an "Alternative Evaluation Tool" which is used to screen the list of projects identified during T&D planning to assess where distributed resources, including energy storage, could be both technically feasible and cost competitive as compared to traditional T&D solutions. If a study shows that distributed resource alternatives are feasible and potentially cost-competitive that project is flagged for detailed analysis.

To help illustrate the potential for distribution capacity deferral, PacifiCorp assessed the peak loading and forecasted growth at each of the distribution substations across its system. Once peak loading reaches 90 percent of a distribution substations capability, PacifiCorp takes steps to either reconfigure the loads or add capacity to ensure that it remains sufficient to serve customers. For this analysis, substations were classified as having a high potential for distribution capacity deferral if their current loading is at or above the 90 percent threshold, medium if they are

anticipated to exceed the 90 percent threshold within the next twenty years, and low if they are not expected to exceed the 90 percent threshold in the next twenty years. The results shown in Table Q.3 identify the portion of PacifiCorp's distribution load that is part of each of these three categories in each state. The "low" category represents a majority of PacifiCorp's system, which indicates that programs targeting distributed resources in specific locations have the potential to provide significantly greater value.

Table Q.3 – Share of Distribution Load by State with Potential Upgrade Deferral

State	High	Medium	Low
CA	13%	3%	84%
ID	38%	38%	23%
OR	13%	36%	51%
UT	8%	30%	62%
WA	24%	32%	43%
WY	7%	21%	72%
Total	**13%**	**31%**	**56%**

Because distribution upgrades are primarily driven by load growth, distributed resources need to be sufficient to maintain load within existing peaks to defer distribution upgrades. Energy storage resources can be cost-effective to cover brief peaks, but are less cost-effective as the duration of the shortfall increases. To the extent load in an area continues to grow, the deferred distribution upgrade is likely to be necessary eventually. Table Q.4 illustrates the distribution load growth by state that is likely to trigger distribution upgrades during the IRP planning period. The forecasted distribution capacity deferral value is $21.89/kw-yr (2018$) for substations with a planned upgrade that can be deferred indefinitely. If distributed resource programs result in resources on a mix of substations that include medium or low value areas, the effective distribution capacity deferral value would be reduced.

Table Q.4 - Forecasted Distribution Load Growth Above the 90 Percent Planning Threshold

Year	CA	ID	OR	UT	WA	WY	Total
2019	1	19	30	79	12	9	151
2020	1	22	30	108	18	11	190
2021	1	22	30	116	18	11	199
2022	1	23	42	123	21	11	221
2023	1	23	42	164	25	11	266
2024	1	31	51	164	25	11	283
2025	1	34	63	165	26	11	300
2026	2	35	72	170	26	11	315
2027	2	35	74	172	30	14	327
2028	2	35	77	194	33	14	354
2029	2	35	86	196	33	55	406
2030	2	39	90	206	33	55	424
2031	2	40	94	248	33	59	476
2032	2	40	99	279	33	59	511
2033	2	43	99	313	36	61	554
2034	2	46	101	353	36	63	601
2035	2	46	106	357	36	68	615
2036	2	51	108	367	36	68	633
2037	2	51	115	384	36	68	655
2038	2	52	118	395	43	70	679

Generation Capacity

Background

To provide reliable service to customers, a utility must have sufficient resources in every hour to:

- Serve customer load, including losses and any unanticipated load increase.
- Hold operating reserves to meet NERC and WECC reliability standards, including contingency, regulation, and frequency response.
- Replace resources that are unavailable due to:
  - Forced and planned outages
  - Dry hydro conditions
  - Wind and solar conditions
  - Market conditions

PacifiCorp refers to "Generation Capacity" as the total quantity of resources necessary to reliably serve customers, after accounting for the items above. The level of resources needed for reliable operation is discussed in Volume II, Appendix I (Planning Reserve Margin Study). For the 2019 IRP, PacifiCorp selected a planning reserve margin of 13 percent over its coincidental peak loads and this is applied to both summer and winter peaks. The planning reserve margin does not translate directly into either resources or need. Instead, PacifiCorp assesses the capacity contribution of each of its resources in Volume II, Appendix N (Capacity Contribution Study). Capacity contribution represents the portion of a resource that can be counted on to reliably meet peak demand. This is inherently dependent on the composition of a portfolio, so for the first time in the 2019 IRP, PacifiCorp performed a detailed assessment of the hourly reliability of each portfolio and increased requirements for portfolios that failed to achieve a minimum reliability level.

All resources contribute to a reliable portfolio, but they do so in ways that are not straightforward to measure. Removing a resource from a portfolio will make that portfolio less reliable unless it is replaced with something else, ideally in a quantity that provides an equal capacity contribution and results in equivalent reliability. As indicated above, reliability is difficult to predetermine, hence PacifiCorp's reliance on a reliability assessment for the 2019 IRP.

As a result, the most direct measurement of the generation capacity value of a resource is to build a portfolio that includes it, and compare that portfolio to one without it. But even that analysis would identify more than just generation capacity value, as it would also include energy and operating reserve impacts related to both the resource being added and resources that were delayed or removed. This is an essential description of the steps used to develop portfolios in the IRP, and while powerful, the IRP models and tools do not lend themselves to ease of use, rapid turnaround, or the evaluation of small differences in portfolios.

As an alternative, a simplified approach to generation capacity value can be used when the resources being evaluated are similar to the proxy resource additions identified in the IRP preferred portfolio. The premise of the approach is that the IRP preferred portfolio resources represent the least-cost, least-risk path to reliably meet system load. The appropriate level of generation capacity value is inherently embedded in the IRP preferred portfolio resource costs, because those resources achieve the stated goal of reliable operation. Again, while it is difficult to identify exactly what portion of the resource cost should be considered generation capacity as opposed to energy or operating reserve value, the total resource cost is straightforward and known.

The 2019 IRP preferred portfolio includes stand-alone four-hour lithium-ion battery storage resources starting in 2028. These resources have annual fixed costs (capital recovery and fixed operations and maintenance) of approximately $173/kw-yr in 2028. After netting out energy values based on market as described above, the remainder is $111/kw-yr (2028$) based on Four Corners market prices and $130/kw-yr (2028$) based on Mid-Columbia market prices. In 2018 dollars, this is equivalent to $89-$104/kw-yr (2018$). These values do not include any value from operating reserves or from charging during periods of renewable resource over-supply when the marginal dispatch cost on PacifiCorp's system is less than market due to transmission congestion or limits on market volumes.

While uncertainty remains in these generation capacity values, the uncertainty in the conclusions can be small to the extent a resource being evaluated provides largely the same services as the resource in the 2019 IRP. As a result, it is reasonable to compare the costs and benefits of energy storage resources that provide energy value, operating reserves, and charging during renewable resource over-supply to the costs and implicit benefits of energy storage resources in the 2019 IRP, which also provide those same services. To the extent the resources being evaluated vary significantly in characteristics or timing relative to the resources in the 2019 IRP preferred portfolio, a more thorough analysis using a production cost model would be necessary to ensure the relative benefits of preferred portfolio resources and a resource being evaluated are characterized accurately.

Part 2: Energy Storage Operating Parameters

This section discusses some of the key operating parameters associated with energy storage resources. Beyond just defining the basic concepts, it is important to recognize the specific ways in which these parameters are measured, and ensure that any comparison of different technologies or proposals reports equivalent values. For example, many battery systems operate using direct current (DC) rather than the alternating current (AC) of the vast majority of the electrical grid. When charging or discharging from the grid, inverters must convert DC power to AC power, which creates losses that reduce the effective output when measured at the grid, rather than at the battery. To handle this distinction, PacifiCorp uses the AC measurement at the connection to the electrical grid for all parameters, as this aligns with the effective "generation input" of an energy storage resource. As previously discussed, an additional adjustment for line losses on the electrical grid may also be necessary, but that is dependent on the location and conditions on the electrical grid, rather than the energy storage resource.

- **Discharge capacity**: The maximum output of the energy storage system to the grid, on an AC-basis, measured in megawatts (MW). This is generally equivalent to nameplate capacity.
- **Storage capacity:** The maximum output of the energy storage system to the grid, on an AC-basis, when starting from fully charged, measured in megawatt-hours (MWh).
- **Hours of storage:** The length of time that an energy storage system can operate at its maximum discharge capacity, when starting from fully charged, measured in hours. Generally, the hours of storage will be equal to storage capacity divided by discharge capacity.
- **Charge capacity:** The maximum input from the grid to the energy storage system, on an AC-basis, measured in megawatts (MW).

- **Round-trip efficiency:** The output of the energy storage system to the grid, divided by the input from the grid necessary to achieve that level of output, stated as a percentage. A storage resource with eighty percent efficiency will output eight MWh when charged with ten MWh. If charge and discharge capacity are the same, losses result in a longer charging time. For instance, an energy storage system with four hours of storage, eighty percent efficiency, and identical charge and discharge capacity would require five hours to fully charge (4 hours of discharge divided by 80 percent discharge MWh per charge MWh).
- **State of charge:** This is a measure of how full a storage system is, calculated based on the maximum MWh of output at the current charge level, divided by the storage capacity when fully charged, and is stated as a percentage. One hundred percent state of charge indicates the storage system is full and can't store any additional energy, while zero percent state of charge indicates the storage system is empty and can't discharge any energy. As previously indicated, PacifiCorp's state of charge metric is based on output to the grid. As a result, the entire round-trip efficiency loss is applied during charging before reporting the state of charge. For example, a storage system with a ten MWh storage capacity and eighty percent efficiency would only have an eighty percent state of charge after ten MWh of charging had been completed, starting from empty.
- **Station service:** Round-trip efficiency is a measure of the losses from charging and discharging. Some energy storage systems also draw power for temperature control and other needs. This is typically drawn from the grid, rather than the energy storage resource.

Some energy storage technologies experience degradation of their operating parameters over time and based on use. The following parameters are used to quantify the effects of degradation.

- **Storage capacity degradation:** The primary impact of degradation is on storage capacity. Much of the degradation occurs as part of charge-discharge cycles, and can be measured as the degradation per thousand cycles. After one thousand cycles, a four-hour storage system might only be capable of storing 3.5 hours of output. Some storage resources also experience degradation that isn't tied to cycles, for instance based on differing state of charge levels or time.
- **Cycle life:** This is the total number of full charge and discharge cycles that energy storage equipment is rated for. Three thousand cycles is common for lithium-ion resources, but operating under harsh conditions can also cause the effective cycle count to decline faster. Once storage capacity has degraded by thirty percent degradation per cycle may accelerate.
- **Depth of discharge:** Operating at a very high or very low state of charge, particularly for an extended period of time, can cause more rapid degradation. This metric can be used to identify how particular operations impact the effective remaining cycle life.
- **Variable degradation cost:** Lithium-ion energy storage equipment is composed of a large number of battery modules, each of which experience degradation. These modules can be gradually replaced over time to maintain a more consistent storage capacity, or they can be replaced all at once when cycle limits are reached, at the expense of a reduced storage capacity in the interim. In either case, the replacement cost of storage equipment can be expressed per MWh of discharge, and accounted for as part of resource dispatch.

Part 3: Distributed Resource Configuration and Applications

This section described the potential benefits of different distributed resource siting and configuration options. Due to economies of scale, distributed resource solutions generally higher cost relative to utility-scale assets. For example, the 2019 IRP supply-side table shows fixed costs for a fifteen megawatt, four-hour lithium-ion battery costs that are approximately half that of the costs for a one megawatt, four-hour battery. While these savings are appreciable, it should be noted that a fifteen megawatt battery is small and can be considered modular relative to traditional resources such as a simple cycle combustion turbine. Many of PacifiCorp's distribution substations have capacity in excess of fifteen megawatts, such that a battery of that size could be feasible at the distribution level, with the potential for incremental benefits relative to the transmission-connected battery resources modeled as part of the 2019 IRP preferred portfolio. The most cost-effective locations for distributed resource deployment are likely to reflect a balance of local requirements and economies of scale.

Secondary Voltage

A distributed resource which is located downstream from the high voltage transmission grid will have a larger energy impact than its metered output would indicate, due to line losses. This is true for both charging and discharging; however, the marginal loss rate increases with load, so the effects are not equal. To the extent discharging is aligned with periods with higher load, and charging is aligned with periods with lower load, the benefits will increase. For example, the marginal primary voltage losses for Oregon are estimated at 9.5 percent on average across the year. Savings based on primary losses would be appropriate to apply to a resource connected at the secondary voltage level so long as it is not generating exports to the higher voltage system, as losses would still occur within that level, but would be reduced due to lower deliveries across the higher voltage system. When the hourly loss profile is applied to the hourly market prices used to calculate the energy values described in Part 1, the result is 16 percent higher for a four-hour lithium-ion battery. Much of the incremental benefit is due to high loss rates in summer and winter peak load months, when prices are relatively high. For lithium-ion batteries, there is also an incremental benefit related to variable degradation costs. While the effect of losses makes the battery appear larger from a system benefits perspective, it discharges the same amount, so the variable cost component doesn't scale with losses, creating an additional benefit that is captured in this energy margin.

In addition to incremental energy value, resources connected at primary or secondary voltage will also have a proportionately higher generation capacity value. In the example for Oregon above, this amounts to a roughly 11 percent increase in effective capacity contribution based on avoided primary losses.

T&D Capacity Deferral

As indicated in the grid services section, distributed resources can allow for the deferral of upgrades by reducing the peak loading of the transmission and distribution system elements serving their area. In order for deferral to be achieved, a distributed resource must reliably reduce load under peak conditions. However, the timing of peak conditions for a given area is likely to vary from the peak conditions for the system as a whole. As a result, the energy or generation capacity value of energy-limited resources used for a T&D capacity deferral application are likely

to be reduced. For instance, when energy-limited resources are reserved for local area requirements they would not be available for system reliability events or a period of high energy prices.

Combined Solar and Storage

Solar resources can qualify for a thirty percent federal investment tax credit (ITC) if they come online prior to the end of 2023. Thereafter, solar resources will continue to qualify for a ten percent ITC. Storage that is constructed in combination with a solar resource and which is charged using that solar resource for the first five years of operation qualifies for the same ITC as the solar resource. This can result in 10-30 percent reduction in the costs of combined solar and storage, relative to stand-alone storage. There are also construction and operational efficiencies that can further improve the economics of combined storage and solar assets, including shared construction crews, inverters, property, and maintenance.

As a result of the items benefits above, the 2019 IRP found that the inclusion of storage with solar resources produced an across the board benefit relative to portfolios that included new solar resources without storage. The 2019 IRP analysis assumed that storage resources combined with solar would be sized equivalent to 25 percent of the solar nameplate and have four hours of storage. These sizing parameters will evolve as PacifiCorp goes out to procure specific resources to capture the benefits of the expiring ITC at the end of 2023, based on both the costs and effective capabilities of different configurations. In general, energy storage should be sized to allow it to be fully filled each day using co-located solar output.

Cost-Effectiveness Results

Table Q.5 provides details on the year-by-year benefits of various lithium-ion battery applications, and identifies years and configurations that are estimated to be cost-effective, either on a stand-alone basis or with the applicable solar ITC at that time.

Since a stand-alone battery is included in the preferred portfolio starting in 2028, it is assumed to be cost effective and providing benefits equal to its costs starting in 2028. Prior to 2028, benefits are based on the intra-hour flexible reserve credit values and operating reserve benefits through 2023, as the battery penetration in this time frame is unlikely to fully cover the operating reserve requirements. Starting in 2024, benefits are assumed to be based on hourly market energy value and the intra-hour flexible reserve credit values, as the higher value operating reserve values are assumed to be fully satisfied with the 2024 battery resources in the preferred portfolio.

Table Q.5 - Energy Storage Applications - Annual Benefits Stream and Cost-Effectiveness

$/kw-yr	Stand-alone Li-Ion 4hr Fixed Cost	Hourly Market Energy	Intra-hour Flex Credit	Operating Reserve	Utility-scale Resource	Primary Losses Energy	Primary Losses Gen Capacity	Primary Losses	T&D Deferral	Primary + T&D Deferral
2019		22.90	26.19	51.17	77.36	4.00		81.35	22.39	103.74
2020		22.64	26.78	52.34	79.12	3.98		83.10	22.90	106.00
2021		25.52	27.39	53.53	80.93	4.36		85.28	23.42	108.70
2022		29.53	28.02	54.75	82.77	4.78		87.56	23.95	111.51
2023		34.02	28.66	56.00	84.66	5.28		89.94	24.50	114.44
2024		40.54	29.31	57.28	69.85	5.99		75.84	25.06	100.90
2025		46.87	29.98	58.58	76.85	6.36		83.21	25.63	108.84
2026		51.12	30.66	59.92	81.79	6.79		88.58	26.22	114.79
2027		51.43	31.36	61.29	82.79	6.72		89.50	26.81	116.32
2028	172.72	52.15	32.08	62.68	172.72	6.73	18.69	198.13	27.42	225.56
2029	176.66	57.36	32.81	64.11	176.66	7.21	19.11	202.98	28.05	231.03
2030	180.69	64.79	33.56	65.57	180.69	7.92	19.55	208.15	28.69	236.84
2031	184.81	69.40	34.32	67.07	184.81	8.30	19.99	213.11	29.34	242.45
2032	189.02	74.71	35.10	68.60	189.02	8.78	20.45	218.26	30.01	248.27
2033	193.33	79.63	35.90	70.16	193.33	9.20	20.92	223.45	30.70	254.14
2034	197.74	84.30	36.72	71.76	197.74	9.57	21.39	228.70	31.40	260.10
2035	202.25	84.73	37.56	73.40	202.25	9.49	21.88	233.61	32.11	265.73
2036	206.86	88.33	38.42	75.07	206.86	9.68	22.38	238.92	32.84	271.76
2037	211.57	94.67	39.29	76.78	211.57	10.36	22.89	244.82	33.59	278.41
2038	216.40	103.07	40.19	78.53	216.40	11.15	23.41	250.96	34.36	285.32
2039	221.33	105.42	41.10	80.32	221.33	11.41	23.95	256.68	35.14	291.83
2040	226.38	107.83	42.04	82.16	226.38	11.67	24.49	262.54	35.94	298.48
2041	231.54	110.29	43.00	84.03	231.54	11.93	25.05	268.52	36.76	305.28
2042	236.82	112.80	43.98	85.95	236.82	12.20	25.62	274.64	37.60	312.25

Valuation inputs
Cost-effective w/ 30% ITC
Cost-effective w/ 10% ITC
Cost-effective 0% ITC

APPENDIX R –COAL STUDIES

Introduction

The 2019 Integrated Resource Plan (IRP) includes a thorough and robust economic analysis of PacifiCorp's coal units. The coal study analysis conducted in the 2019 IRP was initially prompted by the Public Utility Commission of Oregon (OPUC) in its 2017 IRP acknowledgement order, which administratively established certain study parameters that defined the scope and breadth of the analysis. PacifiCorp met these requirements and then developed a more complete study to ensure that it adequately captured the costs to maintain system reliability. The coal study analyses that informed the 2019 IRP portfolio-development process were completed in three phases:

- Phase One
  Unit-by-unit early retirement studies, which focused on impacts to resource portfolio selections and system costs from the System Optimizer (SO) model, were developed. Each unit-specific early retirement scenario assumes closure at the end of 2022. This phase met requirements set forth by the OPUC 2017 IRP acknowledgement order (Order No. 18-138), and concluded with the June 28-29, 2018 2019 IRP public-input meeting and compliance filing to the OPUC in Docket No. LC-70 on June 29, 2018.

- Phase Two
  A series of studies were produced that expanded the scope of the phase one studies. The expanded scope included an evaluation of unit-by-unity early retirement scenarios using the Planning and Risk model (PaR), stacked retirement scenarios, where multiple early closures were evaluated in a single scenario, and alternative year scenarios, which considered changes in the timing of assumed early closure dates for certain coal units. At this point in the process, PacifiCorp had identified capacity shortfalls in the early retirement scenarios that would compromise system reliability if not remedied. The second phase concluded with the December 2018 coal analysis presented to stakeholders at the December 3-4, 2018 public-input meeting, where PacifiCorp communicated to its stakeholders that additional analysis would need to be developed to address the capacity shortfalls identified in the phase two results.

- Phase Three
  Additional analysis was performed on the stacked retirement scenarios evaluated in phase two of the coal study analyses. The third phase concluded with the April 2019 coal analysis, presented to stakeholders at the April 25, 2019 public-input meeting.

Each of the coal study phases show that early retirement of certain coal units has potential to reduce overall system costs. In particular, the coal studies showed that the greatest customer benefits were most likely to be realized with potential early retirement of coal units at the Naughton and Jim Bridger coal plants located in Wyoming.

This appendix describes the methodology and approach taken in each of the three phases of the coal studies and reports modeling and performance evaluation results. Aligning with expectations communicated to stakeholders at public-input meetings held as the 2019 IRP was being developed, the outcomes of the coal studies were used to inform the 2019 IRP portfolio-development process, which is described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

Phase One: Unit-by-Unit Coal Studies

In its 2017 IRP acknowledgement order (Order No. 18-138), the OPUC established requirements for a unit-by-unit series of coal retirement studies, which were to be completed by June 30, 2018. The requirements set forth in Order No. 18-138 are as follows:

- PacifiCorp agrees to perform 25 SO model runs, one for each coal unit and a base case.
- PacifiCorp agrees to summarize results and provide:
    - A table of the difference in present-value revenue requirement (PVRR) resulting from the early retirement of each unit;
    - An itemized list of coal unit retirement cost assumptions used in each SO model run; and
    - A list of coal units that would free up transmission along the path from the proposed Wyoming wind projects if retired.

These requirements are consistent with OPUC staff data request 65, which was submitted to PacifiCorp during the 2017 IRP acknowledgement proceeding. In this data request, OPUC staff provided additional guidance that established expectations for the scope of the unit-by-unit coal study analysis described in OPUC Order No 18-138. The specific guidance provided in OPUC staff data request 65 include:

- PacifiCorp should assume a December 2022 retirement date for each early retirement run.
- PacifiCorp should assume Reference Case Regional Haze assumptions (from the 2017 IRP) that are modified to exclude incremental selective catalytic reduction (SCR) costs for Jim Bridger, Hunter, and Huntington in the benchmark case.
- In agreeing to perform this analysis, PacifiCorp cautioned that:
    - The studies would not provide a complete, portfolio-level view of the economics of PacifiCorp's coal portfolio;
    - The structure of the analysis requested by OPUC staff would not capture the system-cost impact that would result from retiring more than one coal unit; and
    - Results from these studies would therefore provide limited insight into a least-cost, least-risk resource portfolio.

Recognizing PacifiCorp's concerns outlined above, the Utah Public Service Commission in its 2017 IRP acknowledgment order in Docket No. 17-035-16 states "we find that additional analysis will be helpful only if it supplements, rather than replaces, the type of coal plant modeling PacifiCorp utilized for its 2017 IRP."

Unit-by-Unit Study Methodology

To meet the requirements set forth in OPUC Order No. 18-138, PacifiCorp developed a portfolio optimization for each coal unit using the SO model, and compared those model results to a benchmark case that assumed continued operation of coal units through their depreciable life,

which for certain units, extends beyond the life assumed in the 2017 IRP preferred portfolio.[1] Consequently, in this context, the benchmark case developed for the coal studies is not intended to represent PacifiCorp's default plan. Rather, the benchmark case developed for the coal studies is only intended to serve as a point of comparison for the unit-by-unit retirement scenarios. Table R.1 summarizes the steps that were followed to produce the unit-by-unit analysis.

Table R.1 – Summary of Unit-by-Unit Methodology Steps

Step	Measure	Description
A	2017-2036 System PVRR (x1)	Base Case (One SO Model Run) • 2017 IRP Update with following modifications • Removal of 161 MW Uinta Wind Project (2021-2036) • 2017 IRP Reference Case Regional Haze assumptions • March 2018 official forward price curve with medium CO_2 price inputs • Results are calculated with and without incremental selective catalytic reduction costs for Jim Bridger 1 and 2
B	2017-2036 System PVRR (x22)	Retirement Cases (22 SO Model Runs) • 2017 IRP Update with following modifications • Removal of 161 MW Uinta Wind Project (2021-2036) • 2017 IRP Reference Case Regional Haze assumptions • March 2018 official forward price curve with medium CO_2 price inputs • No incremental selective catalytic reduction costs • Each run assumes the retirement of a single coal unit at the end of 2022
C	2017-2036 System PVRR(d) (x22)	Present-Value Revenue Requirement Differential (PVRR(d)) • Change in system PVRR between the Base Case (A) and each of 22 Retirement Cases (B)

- High-level estimates of transmission reinforcement costs are applied as an adder to the results from step C.
- Each SO model run reflects unique coal-unit operating cost assumptions consistent with assumed retirement dates (*i.e.*, fuel cost, run-rate operating costs, and decommissioning costs).
- PacifiCorp did not perform SO model runs in step B for Naughton Unit 3 and Cholla Unit 4, which are already assumed to retire before 2022.

Unit-by-Unit Study Results

Table R.2 lists the coal units studied in the unit-by-unit analysis, including each unit's relative ranking of potential customer benefits from a potential early closure based on the SO model optimized portfolio results. Units with the lowest numeric rankings (starting with 1) reported the greatest potential for customer benefits from early retirement. Relative to the Reference Case from the 2017 IRP, the SO model reported lower system costs with an assumed 2022 early retirement date for eight of the 22 units studied (39 percent on a capacity basis). The units with the greatest potential for customer benefits from early retirement on a unit-by-unit basis were Jim Bridger Unit 1, Jim Bridger Unit 2, Naughton Unit 1, and Naughton Unit 2, followed by Hayden Unit 1, Hayden Unit 2, Hunter Unit 1, and Craig Unit 2.

[1] For instance, the 2017 IRP preferred portfolio assumed Jim Bridger Unit 1 would retire at the end of 2028 and Jim Bridger Unit 2 would retire at the end of 2032. The coal study benchmark case assumes that these units continue to operate through 2037.

Table R.2 – Unit-by-Unit Coal Study Results Ranked by Potential Customer Benefits

Coal Unit	PacifiCorp Share Capacity (MW)	PacifiCorp Percentage Share (%)	State	Ranking (High to Low Potential Customer Benefits)
Colstrip 3	74	10	MT	17
Colstrip 4	74	10	MT	16
Craig 1	82	19	CO	11
Craig 2	83	19	CO	9
Dave Johnston 1	106	100	WY	12
Dave Johnston 2	106	100	WY	13
Dave Johnston 3	220	100	WY	14
Dave Johnston 4	330	100	WY	18
Hayden 1	44	24	CO	7
Hayden 2	33	13	CO	8
Hunter 1	418	94	UT	10
Hunter 2	269	60	UT	15
Hunter 3	471	100	UT	20
Huntington 1	459	100	UT	22
Huntington 2	450	100	UT	19
Jim Bridger 1	354	67	WY	1
Jim Bridger 2	359	67	WY	2
Jim Bridger 3	349	67	WY	6
Jim Bridger 4	353	67	WY	5
Naughton 1	156	100	WY	4
Naughton 2	201	100	WY	3
Wyodak	268	80	WY	21

- In the benchmark case, Jim Bridger Unit 1 and Jim Bridger Unit 2 include SCR costs. The installation of SCR equipment would be required to maintain operation of this facility through 2037.
- Cholla Unit 4 and Naughton Unit 3 are not presented because PacifiCorp already assumes that these units will cease operating as a coal fired facility before the end of 2022 and the intent of the unit-by-unit analysis was not to evaluate whether there might be economic savings from operating these units longer.

The unit-by-unit studies completed in phase one of the coal studies have several limitations, described in detail in both the June 29, 2018 compliance filing in OPUC Docket No. LC-70 and as communicated to stakeholders during the June 28-29, 2018 public-input meeting. These limitations include:

- The potential benefits of early retirement for individual units are not additive and system impacts are not linear. The studies did not attempt to capture the impact on system costs if coal unit retirements are stacked (where more than one unit is assumed to retire early).

- The studies did not capture the operational and other system-reliability impacts associated with:
  - Meeting balancing area reserve requirements;
  - Meeting balancing area frequency response requirements;

- Reduced flexibility between balancing areas (*i.e.*, Jim Bridger provides energy and other reliability services in both the east and west balancing areas); and
- Reduced ability to participate in the energy-imbalance market due to a reduction in flexible generation and inability to pass the flex ramp sufficiency test.

- The studies reflect 2017 IRP system planning assumptions and do not capture system planning assumptions that were being updated for the 2019 IRP (*i.e.*, load forecasts, recent resource additions, planning reserve margins, capacity-contribution values, conservation-potential assessment, supply-side resources, *etc.*)

- The studies were limited to SO model analysis and therefore do not analyze scenario-risk and stochastic-risk analysis.

Considering these limitations, PacifiCorp engaged in phase two of the coal studies to advance and improve upon results from phase one. The phase one results helped to prioritize the more detailed analysis that would be prepared in phase two.

Phase Two: Stacked Coal Studies

PacifiCorp presented the results of its stacked study coal analysis at its December 3-4, 2018 public-input meeting. As illustrated below, additional analysis was performed at this stage, including updated unit-by-unit analysis, stacked retirement analysis, and additional analysis to evaluate alternative retirement dates for certain coal units.

All studies in phase two were performed using the most current system planning assumptions under development for the 2019 IRP (*i.e.*, load forecasts, recent resource additions, planning reserve margins, capacity-contribution values, conservation-potential assessment, supply-side resources, *etc.*). Additionally, all studies in phase two reflect enhancements in the form of additional resource options, transmission modeling enhancements, and PaR stochastic analysis. These updates provided significant improvements to the quality of the results used to indicate which units to study further when developing stacked retirement scenarios.

Additional Resource Options

In updating modeling assumptions to align with the 2019 IRP, the updated and expanded coal study analysis developed for this phase included roughly 250 more renewable resource options that were available for selection in the SO model when it develops resource portfolios, inclusive

of customer-preference[2] resources, more geographic locations, more resource types (*i.e.*, solar and wind resources combined with storage), and with updated capacity-contribution levels. This enhancement aligns IRP modeling with the growing diversity of potential projects across PacifiCorp's service area.

Transmission Modeling Enhancement

In the September 27-28, 2019 public-input meeting, PacifiCorp discussed an improvement to overcome transmission modeling limitations in the SO model while reasonably maintaining model performance. Historically, the SO model has been unable to endogenously select among transmission upgrade options when developing its optimized, least-cost mix of resources for a given portfolio. Subsequently, transmission upgrade needs and costs had to be manually evaluated and developed outside the SO model. This advancement of endogenous transmission modeling represents a leap forward in the portfolio-optimization process, despite some resulting impacts on run-time performance. Between June and December 2018, endogenous transmission options were developed, tested and adopted in SO modeling along with validation and reporting features.

This enhancement had important implications for improving the quality of the coal study results. The cost or benefit of a unit retirement at a specific time and location may swing significantly in relation to transmission projects and opportunities to develop replacement resources and brownfield locations following a plant retirement. Additional detail regarding the endogenous transmission modeling approach implemented in the 2019 IRP is provided in Volume I, Chapter 6 (Resource Options).

Stochastic Risk Analysis

Once unique resource portfolios were developed by the SO model, additional modeling was 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 using PaR. The stochastic simulation in PaR produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The PaR 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.[3] The Monte Carlo sampling approach is discussed in more detail in Volume I, Chapter 6 (Resource Options).

Updated Unit-by-Unit Summary Results

Updated unit-by-unit studies were developed in phase two incorporating the enhancements described above. The SO model was used to establish a portfolio for each unit retirement case and the resulting portfolios were then run through the PaR model to assess stochastic performance for the following price-policy scenarios (assumptions for the price-policy scenarios are summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach)):

[2] Refer to Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) for a description of customer preference resources and modeling.
[3] Front-office transactions, or FOTs, included in resource portfolios developed using the SO model are subject to the Monte Carlo random sampling of wholesale electricity prices in PaR.

- Base/Base: Medium gas price assumption with medium carbon dioxide (CO_2) price assumption
- High/High: High gas price assumption combined with high CO_2 price assumption
- Low/None: Low gas price conditions combined with no CO_2 price assumption

Table R.3 summarizes the unit-by-unit rankings from phase two, calculated on a nominal levelized basis under the each of the different price-policy scenarios. A negative value represents the potential for reduced costs when the unit is assumed to retire early. Conversely, a positive value represents the potential for increased costs when a unit is assumed to retire early. As was the case in phase one, the potential benefits of early retirement for individual units are not additive and system impacts are not linear. The potential benefits of retiring more than one unit would not be the same as adding up the potential benefits from the unit-by-unit results. Moreover, as discussed previously, these results (and the results presented in Tables R.4 through Table R.7) do not account for the costs to remedy capacity shortfalls in any given scenario. The cost to remedy capacity shortfalls as necessary to maintain a reliable system were captured in phase three.

Table R.3 – Unit-by-Unit Update (Benefit)/Cost of Retirement

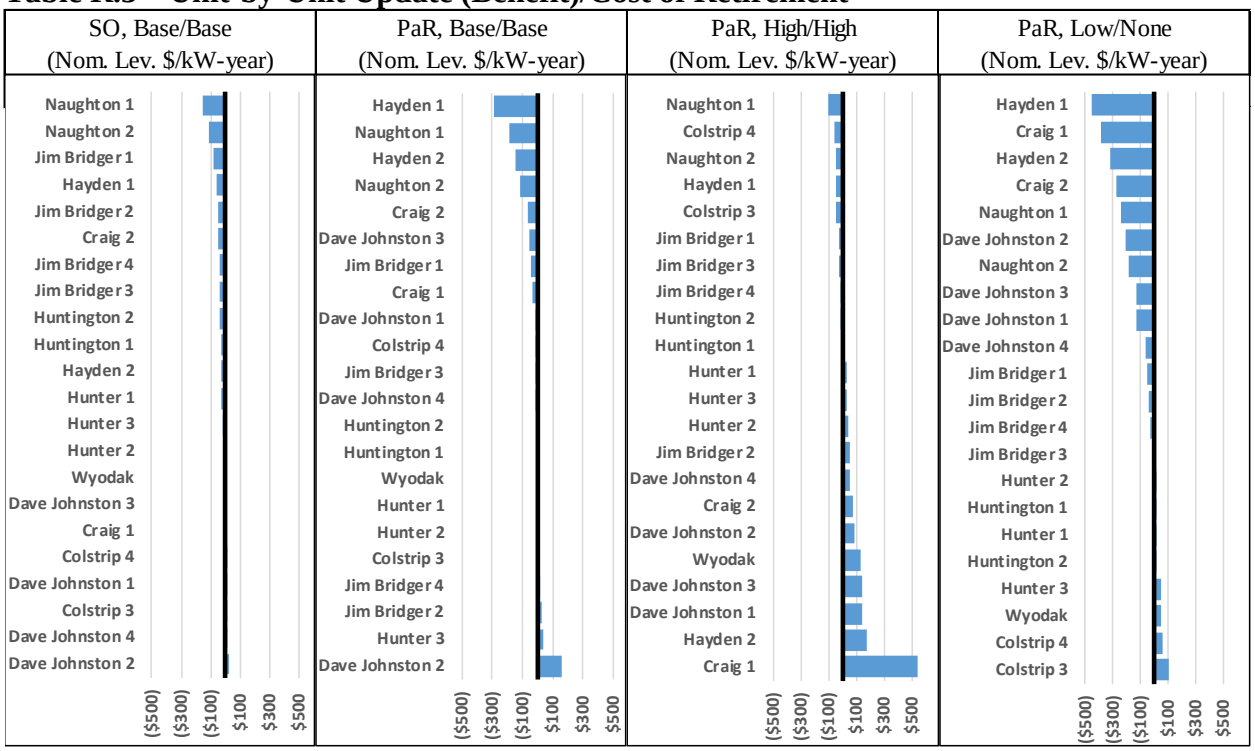


Table R.4 through Table R.7 summarize the unit-by-unit rankings on a present value revenue requirement basis, reporting SO model and PaR results as presented in the December 3-4, 2018 public input meeting.

Table R.4 – SO Model Medium Gas, Medium CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$21,897	n/a
C-02 (Colstrip 3)	$21,906	$9
C-03 (Colstrip 4)	$21,902	$5
C-04 (Craig 1)	$21,897	($0)
C-05 (Craig 2)	$21,875	($22)
C-06 (Dave Johnston 1)	$21,903	$6
C-07 (Dave Johnston 2)	$21,905	$8
C-08 (Dave Johnston 3)	$21,895	($2)
C-09 (Dave Johnston 4)	$21,916	$19
C-10 (Hayden 1)	$21,885	($12)
C-11 (Hayden 2)	$21,893	($4)
C-12 (Hunter 1)	$21,816	($81)
C-13 (Hunter 2)	$21,878	($19)
C-14 (Hunter 3)	$21,853	($44)
C-15 (Huntington 1)	$21,808	($89)
C-16 (Huntington 2)	$21,794	($103)
C-17 (Jim Bridger 1)	$21,690	($207)
C-18 (Jim Bridger 2)	$21,761	($136)
C-19 (Jim Bridger 3)	$21,800	($97)
C-20 (Jim Bridger 4)	$21,797	($100)
C-21 (Naughton 1)	$21,794	($102)
C-22 (Naughton 2)	$21,801	($96)
C-23 (Wyodak)	$21,880	($17)

Table R.5 – PaR Medium Gas, Medium CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$23,310	n/a
C-02 (Colstrip 3)	$23,317	$7
C-03 (Colstrip 4)	$23,302	($8)
C-04 (Craig 1)	$23,304	($6)
C-05 (Craig 2)	$23,281	($29)
C-06 (Dave Johnston 1)	$23,305	($5)
C-07 (Dave Johnston 2)	$23,363	$53
C-08 (Dave Johnston 3)	$23,273	($37)
C-09 (Dave Johnston 4)	$23,304	($6)
C-10 (Hayden 1)	$23,252	($58)
C-11 (Hayden 2)	$23,287	($23)
C-12 (Hunter 1)	$23,341	$31
C-13 (Hunter 2)	$23,334	$24
C-14 (Hunter 3)	$23,438	$128
C-15 (Huntington 1)	$23,326	$17
C-16 (Huntington 2)	$23,310	$0
C-17 (Jim Bridger 1)	$23,197	($113)
C-18 (Jim Bridger 2)	$23,381	$71
C-19 (Jim Bridger 3)	$23,283	($27)
C-20 (Jim Bridger 4)	$23,349	$39
C-21 (Naughton 1)	$23,187	($123)
C-22 (Naughton 2)	$23,212	($98)
C-23 (Wyodak)	$23,323	$13

Table R.6 – PaR High Gas, High CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$28,176	n/a
C-02 (Colstrip 3)	$28,152	($25)
C-03 (Colstrip 4)	$28,145	($31)
C-04 (Craig 1)	$28,265	$89
C-05 (Craig 2)	$28,214	$37
C-06 (Dave Johnston 1)	$28,225	$48
C-07 (Dave Johnston 2)	$28,205	$28
C-08 (Dave Johnston 3)	$28,275	$98
C-09 (Dave Johnston 4)	$28,234	$58
C-10 (Hayden 1)	$28,167	($9)
C-11 (Hayden 2)	$28,203	$26
C-12 (Hunter 1)	$28,258	$81
C-13 (Hunter 2)	$28,255	$79
C-14 (Hunter 3)	$28,297	$121
C-15 (Huntington 1)	$28,215	$38
C-16 (Huntington 2)	$28,172	($4)
C-17 (Jim Bridger 1)	$28,107	($69)
C-18 (Jim Bridger 2)	$28,307	$131
C-19 (Jim Bridger 3)	$28,123	($53)
C-20 (Jim Bridger 4)	$28,156	($20)
C-21 (Naughton 1)	$28,110	($66)
C-22 (Naughton 2)	$28,134	($42)
C-23 (Wyodak)	$28,434	$258

Table R.7 – PaR Low Gas, Zero CO_2 PVRR by Unit

Study	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement
C-01 (Benchmark)	$19,644	n/a
C-02 (Colstrip 3)	$19,701	$57
C-03 (Colstrip 4)	$19,678	$35
C-04 (Craig 1)	$19,579	($64)
C-05 (Craig 2)	$19,513	($131)
C-06 (Dave Johnston 1)	$19,601	($42)
C-07 (Dave Johnston 2)	$19,572	($71)
C-08 (Dave Johnston 3)	$19,554	($89)
C-09 (Dave Johnston 4)	$19,581	($62)
C-10 (Hayden 1)	$19,553	($91)
C-11 (Hayden 2)	$19,596	($48)
C-12 (Hunter 1)	$19,675	$31
C-13 (Hunter 2)	$19,658	$14
C-14 (Hunter 3)	$19,796	$153
C-15 (Huntington 1)	$19,670	$26
C-16 (Huntington 2)	$19,696	$53
C-17 (Jim Bridger 1)	$19,504	($140)
C-18 (Jim Bridger 2)	$19,553	($90)
C-19 (Jim Bridger 3)	$19,642	($2)
C-20 (Jim Bridger 4)	$19,578	($65)
C-21 (Naughton 1)	$19,484	($160)
C-22 (Naughton 2)	$19,488	($156)
C-23 (Wyodak)	$19,746	$103

Alternate Year Unit Analysis

PacifiCorp selected units for further alternate-year analysis based on the unit-by-unit SO model results. Based on the initial SO model results, the following units were selected to test the impacts of delaying individual unit retirements:

- Naughton Unit 1
- Naughton Unit 2
- Jim Bridger Unit 1
- Hayden Unit 1

Table R.8 reports the SO model outcomes of the alternate year studies, and indicates that delaying the retirement of individual units, before accounting for incremental reliability resources needed to remedy capacity shortfalls, in the unit-by-unit studies would reduce potential benefits.

Table R.8 – SO Model Alternate Year Analysis, Medium Gas, Medium CO_2

Study	Alternate Year	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement	Change from 2022 Retirement Assumption
C-01 (Benchmark)	n/a	$21,897	n/a	n/a
C-25 (Naughton 1)	2025	$21,887	($10)	$92
C-26 (Naughton 1)	2028	$21,915	$18	$120
C-27 (Naughton 2)	2025	$21,882	($15)	$81
C-28 (Naughton 2)	2028	$21,915	$18	$114
C-29 (Jim Bridger 1)	2025	$21,756	($141)	$66
C-30 (Jim Bridger 1)	2028	$21,773	($124)	$83
C-31 (Jim Bridger 1)	2031	$21,788	($109)	$99
C-32 (Hayden 1)	2025	$21,884	($13)	($1)
C-33 (Hayden 1)	2028	$21,888	($9)	$3

To confirm this finding, PacifiCorp conducted additional analysis of these studies using PaR. Table R.9 reports results consistent with the SO Model results—before accounting for incremental reliability resources needed to remedy capacity shortfalls, potential benefits for early retirement are greatest with assumed retirement at the end of 2022. Based on results of the alternate-year cases, the stacked-retirement cases developed in phase two of the coal studies assume early retirement of units at the end of 2022.

Table R.9 – PaR Alternate Year Analysis, Medium Gas, Medium CO_2

Study	Alternate Year	PVRR ($m)	PVRR(d) (Benefit)/Cost of 2022 Retirement	Change from 2022 Retirement Assumption
C-01 (Benchmark)	n/a	$23,310	n/a	n/a
C-25 (Naughton 1)	2025	$23,275	($35)	$87
C-26 (Naughton 1)	2028	$23,290	($20)	$103
C-27 (Naughton 2)	2025	$23,277	($33)	$65
C-28 (Naughton 2)	2028	$23,298	($12)	$86
C-29 (Jim Bridger 1)	2025	$23,270	($40)	$73
C-30 (Jim Bridger 1)	2028	$23,262	($48)	$64
C-31 (Jim Bridger 1)	2031	$23,238	($72)	$40
C-32 (Hayden 1)	2025	$23,271	($39)	$20
C-33 (Hayden 1)	2028	$23,277	($33)	$25

Stacked Study Methodology

Based on the outcomes of the updated unit-by-unit analysis, eight stacked-retirement cases were defined to analyze retirement depth for nine coal resources with the highest potential for customer benefits. Table R.10 identifies these cases by name, retired units and the total nameplate of the included retirements.

Each stacked case required the development of a unique set of assumptions, accounting for fuel costs, decommissioning costs, contractual obligations, and the potential loss of existing cost-savings for co-located facilities.

The SO model was used to establish a portfolio for each stacked-retirement case and the resulting portfolios were then run through PaR to assess stochastic performance for the following price-policy scenarios (assumptions for the price-policy scenarios are summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach)):

- Base/Base: Medium gas price assumption with medium CO_2 price assumption
- High/High: High gas price assumption combined with high CO_2 price assumption
- Low/Zero: Low gas price conditions combined with no CO_2 price assumption

Table R.10 – Stacked Retirement Cases

Case Name	2022 Retirements	Nameplate Retired (MW)
C-34	Naughton 1-2 (2022)	357
C-35	Naughton 1-2 (2022) Jim Bridger 1 (2022)	711
C-36	Naughton 1 (2022) Jim Bridger 1 (2022)	510
C-37	Naughton 1 (2022) Jim Bridger 1 (2022) Hayden 1 (2022)	554
C-38	Naughton 1-2 (2022) Hayden 1 (2022) Jim Bridger 1 (2022)	755
C-39	Naughton 1-2 (2022) Hayden 1 (2022) Jim Bridger 1 (2022) Craig 2 (2022)	834
C-40	Naughton 1-2 (2022) Hayden 1 (2022) Jim Bridger 1-2 (2022) Craig 2 (2022)	1,193
C-41	Naughton 1-2 (2022) Jim Bridger 1-2 (2022) Hayden 1-2 (2022) Craig 1-2 (2022) Dave Johnston 3 (2022)	1,529

Stacked Study Results

Table R.11 summarizes the stacked study results under the Base/Base price-policy scenario. Cases C-35, C-38, and C-39 show the largest potential benefits, and the PVRR(d) results for these three cases are very close to one another. Cases C-40 and C-41, both in excess of 1,000 megawatts (MW) of incremental early retirements relative to the benchmark case, show a net cost. As discussed previously, these results (and the results presented in Table R.12 and Table R.13) do not account for the costs to remedy capacity shortfalls.

Table R.11 – Planning and Risk Medium Gas, Medium CO_2 PVRR by Study

Base/Base Case	PVRR	PVRR(d) (Benefit)/Cost of Retirement ($m)
C-01 (Benchmark)	$23,310	n/a
C-34	$23,180	($130)
C-35	$23,009	($301)
C-36	$23,286	($24)
C-37	$23,288	($22)
C-38	$23,002	($307)
C-39	$22,993	($317)
C-40	$23,483	$173
C-41	$23,600	$290

Table R.12 summarizes the stacked study results under the High/High price-policy scenario. As in the base/base price-policy scenario, Cases C-35, C-38, and C-39 show the largest potential benefits. Cases C-40 and C-41, both in excess of 1,000 MW of incremental early retirements relative to the benchmark case, continue to show a net cost.

Table R.12 – Planning and Risk High Gas, High CO_2 PVRR by Study

High/High Case	PVRR ($m)	PVRR(d) (Benefit)/Cost of Retirement ($m)
C-01 (Benchmark)	$28,176	n/a
C-34	$28,109	($67)
C-35	$27,897	($279)
C-36	$28,252	$76
C-37	$28,249	$72
C-38	$27,896	($280)
C-39	$27,877	($299)
C-40	$28,397	$221
C-41	$28,249	$368

Table R.13 summarizes the stacked study results under the low/zero price-policy scenario. As in the base/base and high/high price-policy scenarios, Cases C-35, C-38, and C-39 show the largest potential benefits, and the PVRR(d) results for these three cases are reasonably close. Cases C-40 and C-41, both in excess of 1,000 MW of incremental early retirements relative to the benchmark case, continue to show a net cost.

Table R.13 – Planning and Risk Low Gas, No CO_2 PVRR by Study

Low/Zero Case	PVRR ($m)	PVRR(d) (Benefit)/Cost of Retirement ($m)
C-01 (Benchmark)	$19,644	n/a
C-34	$19,487	($156)
C-35	$19,386	($257)
C-36	$19,549	($95)
C-37	$19.573	($71)
C-38	$19,359	($285)
C-39	$19,336	($308)
C-40	$19,747	$103
C-41	$19,828	$184

Initial Reliability Assessment

While the December 2018 stacked coal studies incorporated important enhancements in methodology and the alignment of data to the 2019 IRP planning assumptions, a method had not yet been fully developed to capture the operational and other system-reliability impacts associated with potential early coal unit retirements.

PacifiCorp performed an initial reliability assessment on a sampling of three cases using an hourly deterministic PaR run for 2023, which is the first full year after assumed coal unit retirements. The deterministic run provides the granularity necessary to represent system reliability shortfalls that may be lost in aggregated data, a factor of increasing importance as flexible resources are retired and potentially replaced with non-dispatchable variable resources. Because deterministic studies lack stochastic shocks, thermal units are modeled using de-rated capacity to account for unplanned outages.

For these initial reliability studies, system balances were summarized for load, net load (load net of energy efficiency, private generation, wind, and solar), spinning reserves, non-spinning reserves, and regulation reserves and compared to the type and amounts of resources providing system services across each hour of several selected days. Selected days included peak load days and peak net-load ramp days. Shortfalls were measured for spinning, non-spinning, and regulating reserves, as well as load. Table R.14 summarizes the aggregated findings of the initial reliability assessment.

Capacity shortfalls were observed in 2023, the year after early retirements, in each of the sample cases, and the number of occurrences and the magnitude of the worst occurrence increased in cases with more stacked retirements. The results confirmed that the retirement cases could degrade system reliability, and the potential cost to remedy these capacity shortfalls was not directly factored into the phase two results (i.e., via a potential addition or change in the resource mix to alleviate capacity shortfalls). Addressing these capacity shortfalls observed in the phase two results was the primary objective of phase three of the coal studies.

Table R.14 – Reliability Analysis Capacity Shortfalls

Case	Shortfall Hours	Maximum Shortfall (MW)
C-01 (Benchmark)	29 (0.3%)	290
C-35	146 (1.7%)	318
C-40	609 (7.0%)	351

Phase Three: Reliability Analysis of Coal Studies

From December 2018 through April 2019, PacifiCorp continued in its efforts to address the capacity shortfalls observed in preliminary results as part of this stage of the coal studies. Four public-input meetings were held including the April 25, 2019 meeting, which concluded the coal studies. During these months several shortfall mitigation enhancements were made to improve model representation, and a path forward was identified to address reliability concerns.

Stakeholder Feedback

As an outcome of the phase two stacked-retirement results, two additional cases were developed in response to stakeholder interest, cases C-42 and C-43. Case C-42 examined the impacts of retiring the four coal units most consistently reporting high customer benefits over the course of the coal studies. C-43 examined the impacts of replacing a Jim Bridger unit with a Dave Johnston unit. Table R.15 provides the assumed retirements of the two additional cases plus the total retired nameplate capacity assumed for each case.

Table R.15 – Additional Stacked Coal Studies

Case Name	2022 Retirements	Nameplate Retired (MW)
C-42	Naughton 1-2 (2022) Jim Bridger 1-2 (2022)	1,063
C-43	Naughton 1-2 (2022) Jim Bridger 1 (2022) Dave Johnston 3 (2022)	928

Coal Unit Focus

At the March 21, 2019 public-input meeting, PacifiCorp presented analysis of real levelized cost rankings of the coal units as an additional verification of the coal units which were to be the focus of the stacked-retirement cases. While this analysis is independent of direct locational factors tied to the IRP topology, the findings reported in Table R.16 generally confirms the focus of specific units established by the phase two coal studies completed in December, 2018.

Table R.16 – Real Levelized Cost Rankings of Coal Units

	Real Levelized Cost Rankings				
	Aggregate Rank	O&M Rank	CapEx Rank	Full Load Fuel Rank	Dec 3-4 PVRR(d) Rank
C-02 (Colstrip 3)	14	7	5	18	15
C-03 (Colstrip 4)	12	6	3	16	10
C-04 (Craig 1)	6	3	14	9	11
C-05 (Craig 2)	5	4	4	10	7
C-06 (Dave Johnston 1)	19	11	21	19	13
C-07 (Dave Johnston 2)	20	10	20	20	21
C-08 (Dave Johnston 3)	21	9	22	21	6
C-09 (Dave Johnston 4)	22	12	19	22	11
C-10 (Hayden 1)	1	1	10	1	4
C-11 (Hayden 2)	2	2	16	3	9
C-12 (Hunter 1)	11	14	12	11	19
C-13 (Hunter 2)	15	15	13	14	18
C-14 (Hunter 3)	13	18	15	12	22
C-15 (Huntington 1)	18	17	17	15	17
C-16 (Huntington 2)	16	16	18	13	14
C-17 (Jim Bridger 1)	7	20	2	6	2
C-18 (Jim Bridger 2)	9	19	1	8	5
C-19 (Jim Bridger 3)	10	21	7	7	8
C-20 (Jim Bridger 4)	8	22	11	5	20
C-21 (Naughton 1)	4	5	6	4	1
C-22 (Naughton 2)	3	8	9	2	3
C-23 (Wyodak)	17	13	8	17	16

The top candidate list in both views include Naughton, Jim Bridger, Hayden and Craig units. While the Dave Johnston units were not indicated in this new analysis, Dave Johnston Unit 3 was retained in certain cases for completeness and in response to stakeholder interest.

Shortfall Mitigation

Renewable Regulation Reserves

Wind and solar resources with requisite contractual rights and controls can provide regulation reserves when forecasted output can be curtailed to free-up operating capacity on the system. Curtailment results in:

- Replacement energy cost (typically market)
- Lost renewable energy credit revenue, where applicable (only included where explicitly known)
- Lost production tax credits, where applicable

- Avoided taxes (Wyoming wind only)

To mitigate the impacts of curtailments, wind and solar resources with requisite contractual rights and controls were modeled as dispatchable resources in PaR.

Hydro Dispatch Configuration
To better account for the flexibility of dispatchable hydro resources, these resources were configured for spring months (February through May in this context) to maximize reserve capability by establishing a consistent monthly dispatch rather than shaping to load.

Non-Peak Front Office Transaction Modeling
Modeling enhancements that address the modeling of dispatchable wind, solar, and hydro resources can result in less energy to serve load, so their viability in mitigating operating-reserve shortfalls may be restricted by limits on market purchases. Recognizing that market conditions vary by season, front office transaction (FOT) limits, which were established with a focus on summer and winter peak-load periods, are increased during the spring and fall to align with firm transmission rights. The increase is from 1,425 MW to 2,277 MW in these periods.

Lewis River Hydro Project Refinement
The original and standard model configuration led PaR to use the Lewis River Hydro project to shave peak load using available energy over a sample week for a given month. Any remaining capacity was then available for use as operating reserves.

PacifiCorp tested and implemented a modeling enhancement allowing PaR to shave peak load, using available energy of a sample week for a given month, net of wind, solar, battery storage, energy efficiency, and private generation resources (i.e., net load). Any remaining capacity, but no less than 10 percent of the Lewis River Hydro project, is considered available for use as operating reserves.

Battery Storage Optimization
PacifiCorp initially attempted to mimic the model settings used to enhance PaR's use of the Lewis River Hydro project to improve its use of battery-storage resources (dispatch, charging, and reserve resources). However, unlike the Lewis River Hydro project, battery-storage resources do not have an established volume of energy to use over a sample week in a given month.

Given complexity of PacifiCorp's system, the PaR model experienced difficulty optimizing the dispatch for battery storage resources. To improve upon this shortcoming in the PaR model, PacifiCorp developed and tested a method to produce an optimized peak-shave/valley-fill profile for these resource outside of PaR that is based on load net of wind, solar, energy efficiency, and private generation resources in any given portfolio. Fixed hourly dispatch, charging, and operating reserves are entered as inputs to the PaR model. This was presented and discussed in the March 21, 2019 public-input meeting.

Model Granularity Cost-Driver Adjustment
At the January 24, 2019 public-input meeting, PacifiCorp discussed that differences between portfolios in some cases were contributing to differences in reserve deficiencies (primarily 2038). These portfolio differences were causing disproportionate impacts on present-value portfolio costs in PaR relative to the SO model. Subsequent testing confirmed that differences in the granularity

between the two models contributes to alternative resource selections and that these resource selections are influencing these seemingly incongruent results.

When cost-driver adjustments based on the differences in hourly granularity between the SO model and PaR model are applied to resource cost inputs used in the SO model, differences to resource portfolio results for seemingly similar cases are more stable and the cost disparity driven by reserve deficiencies are mitigated. Accounting for the reduced hourly granularity in the SO model yields the average solar and wind resource costs shown in Table R.17.

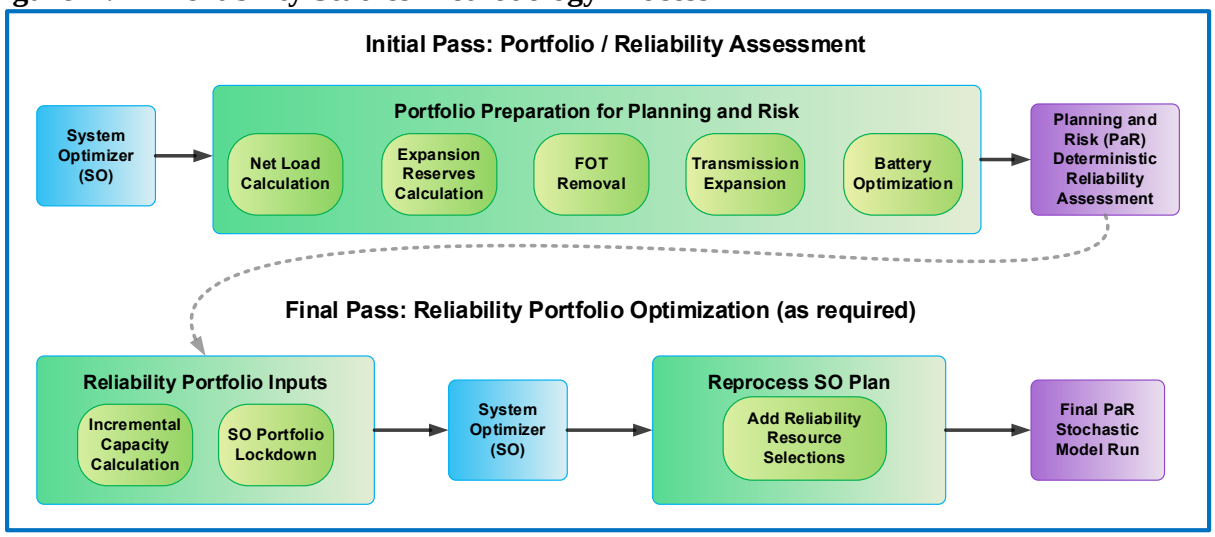
Table R.17 – Model Granularity Cost-Driver Adjustment Summary

Resource Location	Average Resource Cost (increase)/decrease ($/MWh of expected output)	
	Solar	Wind
Oregon	($7.06)	$0.95
Washington	($7.17)	$1.05
Idaho	($7.28)	($0.14)
Utah	($7.73)	($0.35)
Wyoming	($7.33)	($0.90)

Reliability Study Methodology

The modeling enhancements previously described give the SO model and PaR improved insight into the value and capabilities of various resources, and are applicable to every case. This allows the SO model to provide portfolios that are better-aligned with how PaR evaluates the performance and reliability of resources in its more granular perspective. In addition, due to the unique combination of resource types, locations and timing, and their interactions with transmission option modeling, a methodology was necessary to identify and address remaining reliability shortfalls on a case-by-case basis. This method was developed, tested and implemented, and subsequently presented to stakeholders at PacifiCorp's April 25, 2019 IRP public-input meeting. Figure R.1 outlines the development steps followed in this process.

Figure R.1 – Reliability Studies Methodology Process



The reliability methodology is an expansion of the initial reliability analysis explored at the end of 2018 and previously described in Stage Two of the coal studies and is described in more detail below.

Deterministic Reliability Assessment

In the initial reliability analysis, a single deterministic run for the year 2023 was used to assess reliability shortfalls. The methodology adopted in this reliability stage includes a deterministic reliability assessment for three years, 2023, 2030, and 2038. Years 2030 was added as an outcome of a 20-year analysis which determined that 2030 was most frequently the year with highest measured shortfall. Likewise 2038 was added as a bookend, and also because the final year was observed to have relatively high shortfalls.

In evaluating the reliability of the deterministic studies, portfolios must meet four hourly requirements: energy, non-spinning reserve, spinning reserve, and regulation reserve. Separate requirements for East and West are developed in the methodology, but transfers are allowed up to transmission limits. Using the method described in the Initial Reliability Analysis above, the hourly balance of net load and all resource contributions were compared to calculate the shortfall or unused available capacity for each hour. The maximum hourly shortfall (or minimum available) is identified by season. The resulting measures describe four reliability requirements for each proxy year: summer east, summer west, winter east and winter west.

Reliability requirements for the test year 2023 were applied to simulation years 2023 through 2027. Requirements for the test year 2030 were applied to simulation years 2028 through 2036. Requirements for the test year 2038 were applied to simulation years 2037 and 2038.

Uncertainty Requirement

Deterministic studies have the advantage of increased detail through hourly granularity appropriate to identifying potential shortfalls in an increasingly complex system. In the absence of stochastic variance, these studies also reflect “perfect foresight” for the following assumptions:

- Normal load (1-in-2 exceedance)
- Average thermal outages in all hours
- Average hydro conditions
- Fixed variable energy resource generation profiles, and
- Average market prices without electric or natural gas price volatility and physical supply risks

Additional flexible capacity is required beyond the capacity needed to “cure” hourly shortfalls to reliably serve customers considering that the above factors vary from day to day and hour to hour and are not known in advance. To account for these intrinsic uncertainties, 500 MW of additional reliability requirement was added to address significant day-ahead, hour-ahead and real-time unknowns in market supply. This 500 MW capacity requirement is in addition to capacity to sufficient to cover the maximum hourly shortfall identified in the deterministic studies.

The 500 MW incremental requirement relative to a deterministic forecast of loads, outages, market prices, and hydro generation was established upon review of operational data and with consideration of operational experience. In operations, capacity held in reserve for contingency, forecast error and intra-hour variability is approximately 16 percent of peak load. In the summer months, additional capacity is held in reserve to mitigate risks associated with high volatility in

load and resource availability. In 2018, capacity held in reserve that is incremental to the 13 percent planning margin for contingency, forecast error, and intra-hour volatility totaled 295 MW. In 2018, capacity held in reserve to mitigate risk during peak load conditions in the summer months was approximately 241 MW. Combined, these sum to 536 MW. PacifiCorp conservatively adopted the 500 MW figure for planning purposes in the 2019 IRP.

Reliability Portfolio

Once the reliability requirements are known, the SO model is run with the ability to add or accelerate the following resource types relative to the pre-reliability portfolio to meet seasonal east and west incremental requirements: batteries, energy efficiency, gas peaking resources, and pumped storage resources. Other resource types are locked-in at levels determined by the pre-reliability portfolio. The four types of reliability resources are allowed as additions because they provide the necessary flexibility to effectively meet identified shortfalls.

Stochastic Outcomes

The last step in the process is to run a 20-year, 50-iteration PaR study on the resulting reliability portfolio, providing stochastic risk analysis over the full IRP study period.

Reliability Study Results

Table R.18 summarizes the assumed retirements for the complete set of stacked coal reliability cases, including retired capacity and PaR model measured (benefit)/cost.

Table R.18 – Early Retirement Assumptions Summary for all Reliability Coal Studies

Case	Inc. Retired Capacity in 2023 (MW)	PVRR ($m)	Naughton 1	Naughton 2	Bridger 1	Bridger 2	Hayden 1	Hayden 2	Craig 1	Craig 2	Dave Johnston 3
C-34	357	$23,536	✓	✓							
C-35	711	$23,381	✓	✓	✓						
C-36	510	$23,418	✓		✓						
C-37	554	$23,405	✓		✓		✓				
C-38	755	$23,398	✓	✓	✓		✓				
C-39	834	$23,434	✓	✓	✓		✓			✓	
C-40	1,193	$23,317	✓	✓	✓	✓	✓			✓	
C-41	1,529	$23,390	✓	✓	✓	✓	✓	✓	✓	✓	✓
C-42	1,063	$23,302	✓	✓	✓	✓					
C-43	928	$23,458	✓	✓	✓						✓

Note: in all cases it is assumed that Naughton 3 (280 MW) is retired in 2019 and that Cholla 4 (387 MW) is retired at the end of 2020; these units are retired in the benchmark case and therefore not incremental to the stacked-retirement cases listed above.

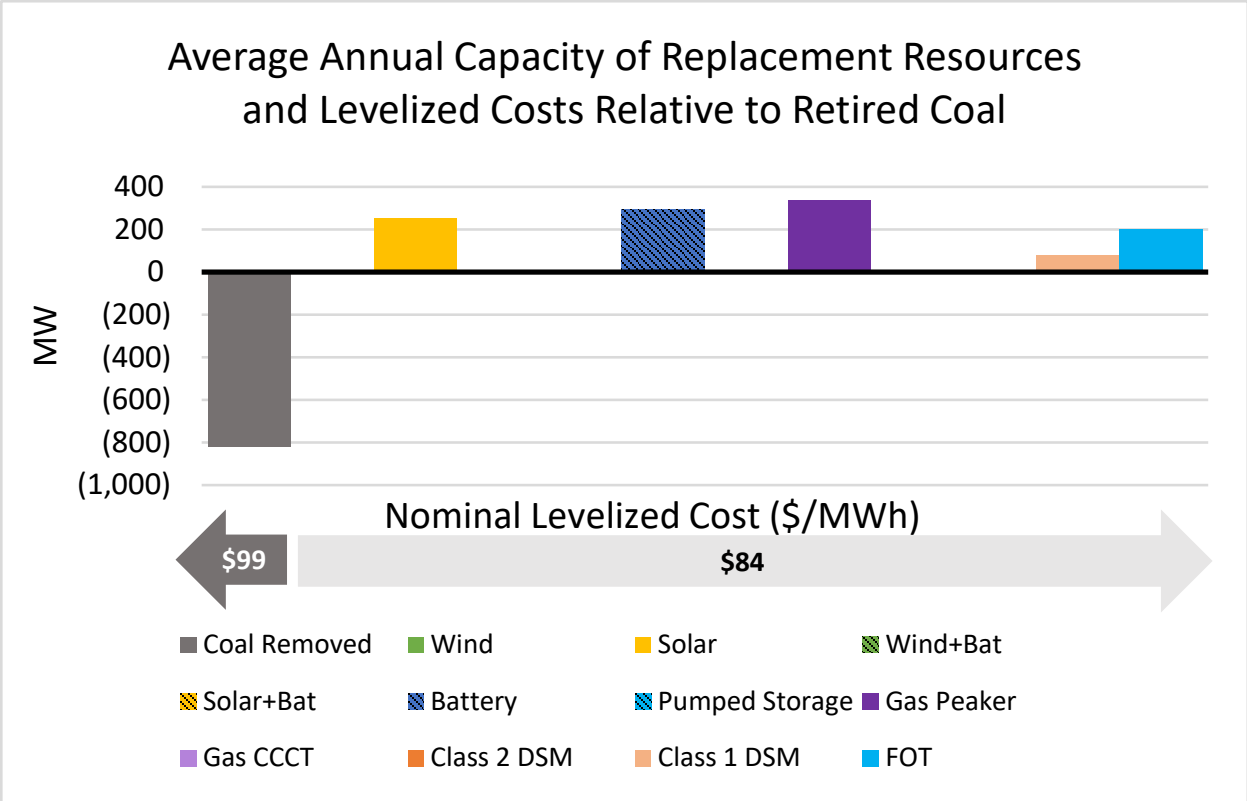
In the final coal study analysis, case C-42 produced the lowest present value revenue requirement (PVRR) total system cost, and therefore the highest potential customer benefits associated with potential early retirement. Cases retiring greater amounts of coal resource (C-40, C-41), or those emphasizing different coal units for early retirement (C-43) reported reduced benefits. This outcome is broadly supported by findings from phase one and two, and again by the real levelized cost rankings of coal unit run-rate costs across the fleet, as reported previously in Table R.16.

Stacked Coal Case C-42

At the April 25, 2019 public-input meeting, PacifiCorp reported a PVRR differential benefit of $248m against the C-01 benchmark case. As noted in the Unit-by-Unit Methodology discussion, above, the benchmark was an administratively established in phase one of the coal studies, and is not representative of PacifiCorp's plan. Also, the $248m figure did not include a correction to the granularity adjustment driver included in the reliability coal studies. Corrected, the PVRR values (given in Table R.18, above) did not alter the conclusions of the April 2019 analysis, which continue to confirm that the greatest potential benefit for early retirements resides with the potential early closure of units at the Naughton and Jim Bridger plants in Wyoming.

Aligned with the April 25, 2019 results, Figure R.2 reports the average annual cost of replacement resources and levelized costs relative to the assumed 2022 accelerated retirements of Jim Bridger Units 1 and 2, and Naughton Units 1 and 2.

Figure R.2 – C-42 Average Annual Replacement Resource Capacity and Levelized Costs



- The nominal levelized cost of retired coal resources is $14.21/MWh higher than the nominal levelized costs of the portfolio of replacement resources.
- CO_2 emission cost savings account for 77.0 percent of the overall benefit associated with accelerated retirement.
- Run-rate fixed costs would need to drop by 26.3 percent to achieve break-even economics with the replacement portfolio.

Conclusions

The updated coal-retirement cases account for incremental resource costs to address reliability issues identified and discussed at the December 3-4, 2018 public-input meeting. The updated analysis shows there are potential customer benefits from accelerating the retirement of certain coal units, where the greatest customer benefits are associated with the potential accelerated retirement of units at the Naughton and Jim Bridger plants located in Wyoming.

Aligning with the long-term study plan established during the 2019 IRP public-input process, the identification of these key units informed PacifiCorp's 2019 IRP portfolio-development process, described in detail in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). The portfolio-development process considers other planning factors not fully evaluated in the coal studies (i.e., Regional Haze compliance, alternative retirement dates for jointly owned coal plants where PacifiCorp is a minority owner and not an operator, alternative timing of potential retirements when accounting for incremental capacity to maintain reliability). Consistent with the findings from the coal study, more than half of the cases developed in the initial phase of the portfolio-development process evaluated varying combinations of retirement dates for Naughton and Jim Bridger units, including coal retirement assumptions from case C-42.